NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Project 2007-09 Generator Verification
MOD-026-1

The Project 2007-09 Generator Verification Standard Drafting Team (GVSDT) thanks all commenters who submitted comments on the proposed revisions to MOD-026-1. The standard was posted for a 30-day public comment period from September 28, 2012 through October 31, 2012. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 45 sets of comments, including comments from approximately 150 different people from approximately 97 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please 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, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration

The majority of commenters agreed with the revisions to Attachment 1 that were made in response to comments in the previous posting. No modifications were made to the draft standard as a result of industry comments for Question 1.

The majority of industry agreed with the revised language to make it clear that technically justified units were limited to units that meet the NERC Registry criteria thresholds and that "technical justification" is defined by demonstrating that the simulated unit or plant response does not match the measured unit or plant response. No modifications were made to the draft standard as a result of industry comments for Question 2.

The following clarifications were made to the standard in response to industry comments:

- Included the term "impedance compensation" to Footnote 1 in the description of what constitutes an excitation control system for synchronous machines.

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

- The SDT has clarified Section 4.2.4 in the Applicability Section as follows: "A technically justified unit that meets NERC registry criteria but is not otherwise included in the above Applicability sections 4.2.1, 4.2.2, or 4.2.3 and is requested by the Transmission Planner."
- The wording, "… or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities …" in Section 5.1 was moved to right after, "… approved by applicable regulatory authorities …" And that same wording was moved to right after, "… following applicable regulatory approval …" in Sections 5.2 to 5.4. Also, the same phrase was appended to each of the four bullets in the Effective Dates Section, "In those jurisdictions where regulatory approval is required:" of the Implementation Plan right after, "… following applicable regulatory approval ..."
- In the Effective Date section 5.3, the word "thirty" after the word "quarter" was inserted in the standard by mistake. As such, the SDT removed the word "thirty."
- Revised the first sentence in R1 to read: "Each Transmission Planner shall provide the following requested information to the Generator Owner within 90 calendar days of receiving a written request:" Stakeholders believed the previous language was not as clear as it could be, so the GVSDT made this revision.
- The SDT has refined the applicable portion of Part 2.1 to read: "Verification for individual units rated less than 20 MVA (gross nameplate rating) in a generating plant (per Section 4.2.1.2, 4.2.2.2, or 4.2.3.2) may be performed using either individual unit or aggregate unit model(s), or both." This ties the requirement to the applicability of the standard per stakeholder request.
- Refined sub part 2.1.2 to read: "Manufacturer, model number (if available), and type of the excitation control system including, but not limited to static, AC brushless, DC rotating, and/or the plant volt/var control function (if installed)."
- Clarified that the response by the Transmission Planner to the Generator Owner concerning the results of testing the model useability is required to be a written response (R6). Also, for ease of reading, moved the last sentence in the requirement to after the Requirement Parts 1-3.

Index to Questions, Comments, and Responses

1. The GVSDT has revised Attachment 1 based on stakeholder comments. Do you agree with this revision? If not, please explain in the comment area below. 12

2. The GVSDT has revised the Applicability section 4.2.4 to make it clear that it applied to technically justified units that meet the NERC Registry criteria. It is emphasized that "technical justification" is defined by demonstrating that the simulated unit or plant response does not match the measured unit or plant response. Do you agree with these revisions? If not, please explain in the comment area below. 28

3. Do you have any other comment, not expressed in questions above, for the GVSDT? 40

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

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Mike Garton	Domion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade	Dominion Resources Services, Inc.	RFC	5, 6
2.	Randi Heise	Dominion Resources Services, Inc.	NPCC	5, 6
3.	Connie Lowe	Dominion Resources Services, Inc.	MRO	5, 6
4.	Michael Crowley	Virginia Electric and Power Company	SERC	1, 3, 5, 6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Stephen J. Berger	PPL Corporation NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda L. Truhe	PPL Electric Utilities Corporation	RFC	1
2.	Brent Ingebrigtson	LG&E KU Services Company	SERC	3
3.	Annette M. Bannon	PPL Generation, LLC on behalf of its Supply NERC Registered Entities	RFC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
4.	Elizabeth A. Davis	PPL EnergyPlus, LLC	MRO	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Jonathan Hayes	Southwest Power Pool Reliability Standards Development Team	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	NA
2.	John Allen	City Utilities of Springfiel	SPP	1, 4
3.	Katie Shea	Westar Energy	SPP	1, 3, 5, 6
4.	Sean Simpson	Board of public utilities of kansas city	SPP	1, 3, 5
5.	Mark Wurm	BPUK	SPP	NA
6.	Lynn Schroeder	Westar Energy	SPP	1, 3, 5, 6
7.	Don Taylor	Westar Energy	SPP	1, 3, 5, 6
8.	Brian Taggert	Westar Energy	SPP	1, 3, 5, 6
9.	Valerie Pinamonti	American Electric Power	SPP	1, 3, 5
10.	John Mayhan	Omaha Public Power District	MRO	1, 3, 5
11.	Ron McIvor	Omaha Public Power District	MRO	5, 1, 3
12.	Mahmood Safi	OPPD	MRO	1, 3, 5
13.	Anna Wang	Burns McDonald	SPP	NA

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Michael Lombardi	Northeast Utilities	NPCC	1
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Robert Pellegrini	The United Illuminating Company	NPCC	1
15.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Michael Schiavone	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

5.	Group	Brandy Spraker	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ian Grant		SERC	3
2.	Marjorie Parsons		SERC	6
3.	David Thompson		SERC	5
4.	Dewayne Scott		SERC	1
5.	Tom Vandervort		SERC	5
6.	Annette Dudley		SERC	5
7.	Paul Palmer		SERC	5
8.	Goerge Pitts		SERC	1
9.	Robert Bottoms		SERC	
10.	David Marler		SERC	1

6.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Burns	Technical Operations	WECC	1
2.	Chuck Matthews	Transmission Planning	WECC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

3.	Erika Doot	Generation Support	WECC	3, 5, 6

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Larry Raczkowski	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	William J Smith	FirstEnergy Corp	RFC	1
2.	Steve Kern	FE Energy Delivery	RFC	3
3.	Doug Hohlbaugh	Ohio Edison	RFC	4
4.	Ken Dresner	FirstEnergy Solutions	RFC	5
5.	Kevin Querry	FirstEnergy Solutions	RFC	6

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Frank Gavvney	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1
6.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
7.	Randy Hahn	Ocala Utility Services	FRCC	3

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	E Scott Miller	MEAG Power	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Steve Jackson	MEAG Power	SERC	3
2.	Steve Grego	MEAG Power	SERC	5
3.	Danny Dees	MEAG Power	SERC	1

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Brenda Hampton	Luminant						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Laney	Luminant Generation Company LLC	ERCOT	5

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Jason Marshall	ACES Power Marketing Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10

1.	John Shaver	Arizona Electric Power Cooperative	WECC	4, 5
2.	John Shaver	Southwest Transmission Cooperative	WECC	1
3.	Tom Alban	Buckeye Power	RFC	3, 4
4.	Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6
5.	Shari Heino	Brazos Electric Power Cooperative	ERCOT	1, 5
6.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
7.	James Manning	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12. Group	Greg Rowland	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils	Duke Energy	RFC	1
2.	Lee Schuster	Duke Energy	FRCC	3
3.	Dale Goodwine	Duke Energy	SERC	5
4.	Greg Cecil	Duke Energy	RFC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13. Group	David Dockery, NERC Reliability Compliance Coordinator	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Central Electric Power Cooperative		SERC	1, 3
2.	KAMO Electric Cooperative		SERC	1, 3
3.	M & A Electric Power Cooperative		SERC	1, 3
4.	Northeast Missouri Electric Power Cooperative		SERC	1, 3
5.	N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6.	Sho-Me Power Electric Cooperative		SERC	1, 3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14. Group	Charles Long	SERC Planning Standards Subcommittee	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren Services Company	SERC	1
2.	James Manning	NCEMC	SERC	1
3.	Jim Kelley	PowerSouth Energy Coop	SERC	1
4.	Philip Kleckley	SC Electric & Gas Co	SERC	1
5.	Bob Jones	Southern Company Service	SERC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
6.	Pat Huntley	SERC Reliability Corp	SERC	10									
7.	David Greene	SERC Reliability Corp	SERC	10									
8.	Amir Najafzadeh	SERC Reliability Corp	SERC	10									
15.	Individual	Shammara Hasty	Southern Company	X		X		X	X				
16.	Individual	David Thorne	Pepco Holdings Inc and Affiliates	X		X							
17.	Individual	ryan millard	pacificorp	X		X		X	X				
18.	Individual	Brian Bejcek	Wolverine Power Supply Cooperative, Inc.	X									
19.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X					
20.	Individual	Jim Watson	Dynegy					X					
21.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
22.	Individual	Lynn Schmidt	NIPSCO	X		X		X	X				
23.	Individual	Cristina Papuc	TransAlta Centralia Generation LLC					X					
24.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
25.	Individual	Winnie Holden	PSEG	X		X		X	X				
26.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
27.	Individual	Michelle R. D'Antuono	Ingleside Cogeneration LP (Voting entity Occidental Chemical Corporation)					X					
28.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
29.	Individual	Ken Gardner	Alberta Electric System Operator (AESO)		X								
30.	Individual	Thad Ness	American Electric Power	X		X		X	X				
31.	Individual	Michael Falvo	Independent Electricity System Operator		X								
32.	Individual	Wryan Feil	Northeast Utilities	X									
33.	Individual	Brian Evans-Mongeon	Utility Services								X		
34.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
35.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X	X	X	X				
36.	Individual	Scott Berry	Indiana Municipal Power Agency										
37.	Individual	Eric Bakie	Idaho Power Company	X		X							

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
38.	Individual	John Yale	Chelan PUD					X					
39.	Individual	Maggy Powell	Exelon Corporation and its affiliates	X		X	X	X	X				
40.	Individual	Kirit Shah	Ameren	X		X		X	X				
41.	Individual	Don Jones	Texas Reliability Entity										X
42.	Individual	Martin Kaufman	ExxonMobil Research and Engineering	X				X					
43.	Individual	Tony Kroskey	Brazos Electric Power Cooperative, Inc.	X									
44.	Individual	Russell Noble	Cowlitz PUD			X	X	X					
45.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration:

Organization	Supporting Comments of “Entity Name”
MEAG Power	Southern CompanyServices, Inc. - Gen
Liberty Electric Power	NAGF
Brazos Electric Power Cooperative, Inc.	ACES Power Marketing
Nebraska Public Power District	MRO NSRF

1. **The GVSDT has revised Attachment 1 based on stakeholder comments. Do you agree with this revision? If not, please explain in the comment area below.**

Summary Consideration: The majority of commenters agreed with the revisions to Attachment 1. No modifications were made to the draft standard as a result of industry comments for Question 1.

Organization	Yes or No	Question 1 Comment
ACES Power Marketing Standards Collaborators	No	(1) While the clarity of Attachment 1 has been improved, we noticed a couple of issues. Note 2 provides guidance for early compliance and we agree that early compliance should be allowable. It establishes that 10 year period begins from the transmittal date. If a GO has data that satisfies the early compliance condition for a verified model and that data is a five years old, the Note would appear to allow the GO to transmit the data to the TP and receive credit for next 10 years effectively creating an initial 15-year re-verification cycle. Is this intended? If not, please provide more guidance for how soon the GO would have to re-verify its model. **Response: The intent of Attachment 1 Note 1 is to establish the recurring 10-year unit verification period start date assuming no consideration for early compliance. Consideration for early compliance is addressed in Note 2. This allows early compliance for a 10-year period. The 10-year period begins when model verification is specified to be "complete" per the regional policies, guidelines, or criteria that were in force. If early compliance is sought based on existing verification compliant with the requirements of this standard, as the SDT strove to write the standard such that the "how's" are specified and not the "what's", the modeling expert is expected to responsibly manage the time between the data**

Organization	Yes or No	Question 1 Comment
		used to verify the model and the subsequent verification and the transmittal of the verified model, documentation, and data to the Transmission Planner. (2) Row 3 in Attachment 1 states that it applies to initial verification for a newly applicable unit or for an existing applicable unit with a new excitation or plant volt/var control system. However, Requirement R4 also applies to changes to the controls systems. Wouldn't complete replacement be a change? We recommend modifying Attachment 1 to avoid this overlap. **Response: The SDT feels like the distinction of a complete replacement of an excitation system merits its own row in Attachment 1 as there is no doubt that this would result in the need to verify the model and is applicable to Requirement 2 and not Requirement 4. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.** (3) Per Requirement R4 and Row 5 in Attachment 1 the GO has 180 days to submit a plan to Transmission Planner to verify the model and then another 365 days to perform the model verification date. That would appear to give the GO approximately a year and half to complete the verification for changes (including replacement) to the control system. Requirement R2 and Row 3 appear to require completion of the verification in 365 days or a year. Please modify the table or requirement to clarify appropriate application. **Response: The time lines for Requirements R2 and R4 are different as the Requirements are different. Requirement R4 specifies the need for model verification due to changes to the excitation control system and plant volt/var control function that alter the equipment response characteristic, and allows 180 days to determine if the model needs to be verified or if the submission of updated data is sufficient. Attachment 1**

Organization	Yes or No	Question 1 Comment
		addresses the required periodicity and acceptable time delays to remain compliant (365 days for activities described in R4 assuming for R4 that the Generator Owner decided that they will verify the model). Conversely, R2 specifies the periodic required model verification and thus no time needs to be allotted to determine if the model needs to be verified – as it must be verified at least once every 10 years. Attachment 1 goes on to specify the required time or anniversary date for which verification per R2 is required.
Response: The GVSDT thanks you for your comments. Please see responses above.		
Tennessee Valley Authority	No	1. Attachment 1, Row Number 4, Recommend deleting “at the same physical location” from the Verification condition. The first condition is recommended to read “Existing applicable unit that is equivalent to another unit(s),” Justification is that if a GO has units that are equivalent and meet the “sister” criteria, the standard does not need to be restricted to the same physical location. The GO identical equipment at different physical locations are still equivalent.
Response: The GVSDT thanks you for your comments. The SDT notes the general agreement among industry with using the proxy unit approach. The SDT respectfully maintains that the “same physical location” requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site review). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g., requirement for PSS in-service). To ensure all GO/GOP equipment meets standard intent, the SDT maintains the “same physical location” requirement is necessary.		
Cowlitz PUD	No	Cowlitz supports the comments put together by the NAGF SRT:1. We recommend removing the first element of the logical AND statement of Attachment 1Row 4 (the same physical location element). If a GO has

Organization	Yes or No	Question 1 Comment
		identical equipment at differentphysical locations, they are equivalent. A sister is a sister independent of the physicallocation. As long as the equipment is identical, the concept should be allowed to applyregardless of location. **Response: The SDT notes the general agreement among industry with using the proxy unit approach. The SDT respectfully maintains that the “same physical location” requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site review). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g., requirement for PSS in-service). To ensure all GO/GOP equipment meets standard intent, the SDT maintains the “same physical location” requirement is necessary.** 2. The SDT should consider moving the capacity factor exemption information found inAttachment 1, row 7 into the applicability section. The applicability section should allow anentity to be able to determine if the standard applies to them and be able to determine thescope of the facilities affected. It is best for those impacted to immediately know which unitsare in the scope and not have to realize the scope from a detailed study of the table ofAttachment 1. This would allow row 7 of Attachment 1 to be deleted. **Response: The SDT decided to place all the scenarios that effectively “exempt” otherwise applicable units in Attachment 1 for clarity. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.**
Response: The GVSDT thanks you for your comments. Please see responses above.		

Organization	Yes or No	Question 1 Comment
Wisconsin Electric Power Company	No	In Row 4, the use of 350 MVA as the cutoff for “sister unit” treatment is not reasonable. We propose the limit can be increased to 500 MVA without any adverse reliability impacts. **Response: Based on industry comments in a previous posting, the SDT raised the proxy unit cutoff from 250 MVA to 350 MVA. This cutoff will enable the inclusion of many steam units at sites with multiple and identical CC plants. The SDT believes that it has achieved stakeholder consensus on the current proxy unit MVA threshold.** Also, in Row 5, the allowable time for existing units to be verified following an indication of model problems should be 2 years, rather than 1 year, since existing legacy units may require additional resources to understand and resolve the issues. **Response: The language and timing in Attachment 1 have been vetted through several comment periods. The SDT believes that we have achieved stakeholder consensus on the current language and timing in Attachment 1 of the standard.**
Response: The GVSDT thanks you for your comments. Please see responses above.		
Oncor Electric Delivery Company	No	Oncor does not support the position that the Transmission Planner (TP) is applicable for this standard. In the ERCOT Interconnection, Section 3 and Section 5 of the ERCOT Nodal Operating Guides prescribes the ERCOT ISO to request and receive generation unit performance data, not the TP.Oncor takes the position that a regional variance be granted for the ERCOT Interconnection such that the standard would prescribe that the Planning Authority (PA) only be the only requestor and receiver of unit performance data to support Section 3 and Section 5 of the ERCOT Nodal Operating Guides. **Response: Regarding the responsibilities assigned to the Transmission**

Organization	Yes or No	Question 1 Comment
		Planner in the draft standard, the SDT believes standard language lines up well with the vast majority of entity business practices in effect regarding the interactions between generation and transmission entities when collaborating on generator dynamic models. There are defined NERC processes outside the GV SDT effort where entities can request a regional variance. Alternatively, the Transmission Planner could delegate the responsibility to another such as its Planning Authority.
Response: The GVSDT thanks you for your comments. Please see responses above.		
PPL Corporation NERC Registered Affiliates	No	Since GO's typically do not have in-house expertise, they would either have to hire consultants to perform model verification or develop in-house expertise, including acquiring simulation software. Are such simulated models/software available today for this on the market? If not, has time been built into the implementation schedule for allowing such creation-it does not appear so? **Response: Generator Owners own the equipment. As such, Generator Owners have access to the equipment, along with access to the equipment's Original Equipment Manufacturer for assistance with technical issues. Historically, the Transmission Planner and Generator Owner entities used to work for the same company, but in today's functional model environment, Transmission Planners often work for a different company than the generation entity. As such, the stated access advantages for the generation entity do not transfer to the Transmission Planner.** **Simulation software is available on the market, and there are consultants available with the necessary expertise to develop the required model data. Additionally, the SDT members believe the implementation plan provides ample time to develop the necessary capability. Significant portions of the power system are already performing routine model data**

Organization	Yes or No	Question 1 Comment
		validation. Also, the first element of the logical AND statement of Attachment 1 Row 4 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. Equivalency of units should be independent of the physical location. **Response: The SDT notes the general agreement among industry with using the proxy unit approach. The SDT respectfully maintains that the "same physical location" requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site walk down). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g., requirement for PSS in-service). To ensure all GO/GOP equipment meets standard intent, the SDT maintains the "same physical location" requirement is necessary.**
Response: The GVSDT thanks you for your comments. Please see responses above.		
Independent Electricity System Operator	No	The long periods in Attachment 1 introduce too much risk: the modeling assumptions (used to derive operating security limits and to make other operating and planning decisions) do not reflect the actual performance of equipment. It would be better for the standard not only to establish the maximum period that Transmission Planners and Generators Owners to complete tasks but also to require the Transmission Planners to establish shorter periods when necessary to reduce the risk to reliability to an acceptable level. In Ontario, Generator Owners have 30 days to transmit the verified model, documentation and data to the Transmission Planner. Generator Owners are also required to indicate immediately following testing whether the installed equipment performed as expected. This

Organization	Yes or No	Question 1 Comment
		approach has worked well. New or modified equipment must first pass through a connection assessment process to establish whether expected performance will meet requirements. Emerging from this process is the Generator Owner's conditional right to connect provided he meets an obligation to demonstrate the installed equipment behaves as well as assumed in the assessment process. In this way, the risk to reliability is reduced to an acceptable level as the exposure of the decision making process to flawed modeling assumptions is minimized. Experience in Ontario has shown that units that were expected to have essentially the same performance often show much larger differences than expected when tested. What seems like small or obscure differences to a Generator Owner can be critical to a Transmission Planner. **Response: The time periods in Attachment 1 have been vetted through several comment periods. The SDT believes that we have achieved stakeholder consensus on the current language and time periods in Attachment 1 of the standard.** Row 4 in Attachment 1 should be amended to require the amount of verification on "sister" units to be accepted by the Transmission Planner. **Response: The SDT notes the general agreement among industry with using the proxy unit approach. The SDT respectfully maintains that the "same physical location" requirement provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site walk down). The SDG believes that the verification conditions listed in Row 4 Attachment 1 are sufficient to assure that the Generator owner would be aware if there were differences between the units at the same location that would affect the model data.** Attachment 1 Row 4 that allows for new or existing units that does not include an active closed loop voltage or reactive power control function

Organization	Yes or No	Question 1 Comment
		should be changed. Given the size of the "applicable unit" virtually all units should be on voltage control unless specifically permitted by the Transmission Planner as is the case in Ontario. The adverse effects to reliability of not being on voltage control are well documented (Note1). The standard should be changed to put the onus on the Generator Owner of units not operating in voltage control to demonstrate continued operation in this mode does not have a material adverse effect on reliability. The standard should requirespecify the a process available for moving an "applicable unit" to closed loop voltage control when the Transmission Planner determines this is necessary.Note1: J.D. Hurley, L.N. Bize, C.R. Mummert C.R,The Adverse Effects of Excitation System Var and Power Factor Controllers, IEEE Transactions on Energy Conversion, Vol 14, No. 4, December 1999 **Response: The SAR for this draft standard calls for the verification of the generator's excitation system model data. Performance or operational requirements are beyond the scope of this standard. Note that the SDT assumes that you meant to refer to Attachment 1 Row 6, not Row 4.**
Response: The GVSDT thanks you for your comments. Please see responses above.		
Ameren	No	There appears to be a discrepancy between the language in the requirement R4 and its VSL compared to Row 3 of the Attachment 1. In the both requirement and VSL, a 180 day period is stated, while in Row 3 of Attachment 1, a 365 day period is stated.
Response: The GVSDT thanks you for your comments. R4 requires a Generator Owner to provide revised model data or plans to perform model verification within 180 days of changes to the equipment. If the Generator Owner chooses to plan to perform model verification, then when that model verification plan is submitted to the Transmission Planner, then in accordance with Requirement 2, Row 5 of Attachment 1 would specify that the Generator Owner has an additional 365 days to actually perform		

Organization	Yes or No	Question 1 Comment
the verification – including transmitting the verified model, documentation, and data to the Transmission Planner.		
Southern Company	No	We recommend removing the first element of the logical AND statement of Attachment 1 Row 4 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. A sister is a sister independent of the physical location. As long as the equipment is identical, the concept should be allowed to apply regardless of location. **Response: The SDT notes the general agreement among industry with using the proxy unit approach. The SDT respectfully maintains that the "same physical location" requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site review). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g., requirement for PSS in-service). To ensure all GO/GOP equipment meets standard intent, the SDT maintains the "same physical location" requirement is necessary.** The SDT should consider moving the capacity factor exemption information found in Attachment 1, row 7 into the applicability section. The applicability section should allow an entity to be able to determine if the standard applies to them and be able to determine the scope of the facilities affected. It is best for those impacted to immediately know which units are in the scope and not have to realize the scope from a detailed study of the table of Attachment 1. This would allow row 7 of Attachment 1 to be deleted. **Response: The SDT decided to place all the scenarios that effectively "exempt" otherwise applicable units in Attachment 1 for clarity. The SDT**

Organization	Yes or No	Question 1 Comment
		believes that we have achieved stakeholder consensus on the current language of the standard.
Response: The GVSDT thanks you for your comments. Please see responses above.		
Cogentrix Energy	No	We recommend removing the first element of the logical AND statement of Attachment 1Row 4 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. A sister is a sister independent of the physical location. As long as the equipment is identical, the concept should be allowed to apply regardless of location. **Response: The SDT notes the general agreement among industry with using the proxy unit approach. The SDT respectfully maintains that the "same physical location" requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site review). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g., requirement for PSS in-service). To ensure all GO/GOP equipment meets standard intent, the SDT maintains the "same physical location" requirement is necessary.** The SDT should consider moving the capacity factor exemption information found in Attachment 1, row 7 into the applicability section. The applicability section should allow an entity to be able to determine if the standard applies to them and be able to determine the scope of the facilities affected. It is best for those impacted to immediately know which units are in the scope and not have to realize the scope from a detailed study of the table of Attachment 1. This would allow row 7 of Attachment 1 to be deleted.

Organization	Yes or No	Question 1 Comment
		Response: The SDT decided to place all the scenarios that effectively "exempt" otherwise applicable units in Attachment 1 for clarity. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.
Response: The GVSDT thanks you for your comments. Please see responses above.		
ISO-New England	No	Row 3 requires model transmittal "within 365 calendar days after commissioning the unit". It is not acceptable in terms of system reliability for a large unit to be operating on the system for 365 days after commissioning without a verified model. FERC approved ISO Tariff language also calls for provision of the model prior to Commercial Operation. The standard would not meet the requirements of the Tariff. Row 7 discusses capacity factor. The capacity factor reference has been removed from the requirements. If the capacity factor is still to be used this is unacceptable from a reliability standpoint. Large generators that have a low capacity factor will be required to operate under extreme conditions when the system is most stressed. A verified model should be provided regardless of capacity factor given this consideration.
Response: The GVSDT thanks you for your comments. This standard addresses model verification, not the submittal of preliminary design models. Model verification can occur only after the equipment is installed. The standard does not address development of the original model during the equipment commissioning process. As discussed in the Comment Form with the first posting of the draft MOD-026 standard, the SDT considered the extent of the facilities to be verified and how to reflect this in the "applicability" of this proposed standard. As a basis, the SDT recognized that the excitation system models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the Field Test, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the exciter models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying excitation system models, the SDT is		

Organization	Yes or No	Question 1 Comment
proposing to require verification of excitation systems associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA thresholds corresponding to 80% of connected MVA or greater for each Interconnection are proposed. It is recognized that certain boundaries within an interconnection, such as BA boundaries, may have more or less than 80% of the connected MVA. **The SDT further believes that a minimum unit interconnection of >100 kV, consistent with the Compliance Registry Guideline, is appropriate. Finally, the SDT believes that the standard should apply to units with a capacity factor such that they are on-line 400 hours or greater a year. The SDT believes that these thresholds will result in substantial accuracy improvement to the excitation models and associated Reliability based limits determined by dynamic simulations, while not unduly mandating costly and time consuming verification efforts. Footnote 4 (footnote 2 in the current draft) is intended to allow the Transmission Planner to request model information, possibly leading to model verification, for units which fall within the NERC Compliance Registry but are not of the base Applicability of this proposed standard.** **Also, the SDT does recognize that Regional variances can be considered if a Region desires to include additional unit MVA in this standard.**		
FirstEnergy	Yes	Although FirstEnergy (FE) agrees with the revision to Attachment 1, we feel that the capacity factor calculation in Row 7 should be a part of Applicability section 4.2 Facilities. The reader of the standard shouldn't have to get to the last row of an attachment to determine as to whether a unit is exempt or not.
Response: The GVSDT thanks you for your comments. The SDT decided to place all the scenarios that effectively "exempt" otherwise applicable units in Attachment 1 for clarity. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.		
Texas Reliability Entity	Yes	As TRE stated in previous comment periods to the standard, we disagree with using the 5% capacity factor (Attachment 1, Row 7) to determine which units need to comply with this Standard. The requirements should apply to all generating units meeting the MVA thresholds, regardless of capacity factor. We recognize this is somewhat alleviated by Requirement

Organization	Yes or No	Question 1 Comment
		R5, which now provides a method for the TP to request a model verification for a unit that has less than 5% net capacity factor if the unit's simulated response fails to match its measured response.
Response: The GVSDT thanks you for your comments. The SDT believes that there is negligible reliability to be gained by testing units with capacity factor of less than 5%. The added cost of testing is not justified. As you have noted, R5 does provide a method for TP to request model verification for a unit if the simulated response fails to match the measured response. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.		
Idaho Power Company	Yes	Idaho Power System Planning agrees with the revisions made to Attachment 1.Idaho Power Generator Owner- Suggest that "commissioning date" due date requirements be changed to "commercial operation date" to be consistent with other standards.
Response: The GVSDT thanks you for your comments. The language in Attachment 1 has been vetted through several comment periods. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.		
Duke Energy	Yes	We recommend removing the first element of the logical AND statement of Attachment 1 Row 4 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. Equivalency of units is independent of the physical location.
Response: The GVSDT thanks you for your comments. The SDT notes the general agreement among industry with using the proxy unit approach. The SDT respectfully maintains that the "same physical location" requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site review). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g., requirement for PSS in-		

Organization	Yes or No	Question 1 Comment
service). To ensure all GO/GOP equipment meets standard intent, the SDT maintains the "same physical location" requirement is necessary.		
Southwest Power Pool Reliability Standards Development Team	Yes	
Bonneville Power Administration	Yes	
Dominion	Yes	
Luminant	Yes	
pacificorp	Yes	
Dynegy	Yes	
TransAlta Centralia Generation LLC	Yes	
PSEG	Yes	
Xcel Energy	Yes	
Ingleside Cogeneration LP (Voting entity Occidental Chemical Corporation)	Yes	
American Transmission Company	Yes	
American Electric Power	Yes	
Northeast Utilities	Yes	
South Carolina Electric and Gas	Yes	

Organization	Yes or No	Question 1 Comment
Exelon Corporation and its affiliates	Yes	
Georgia Transmission Corporation	Yes	

2. **The GVSDT has revised the Applicability section 4.2.4 to make it clear that it applied to technically justified units that meet the NERC Registry criteria. It is emphasized that "technical justification" is defined by demonstrating that the simulated unit or plant response does not match the measured unit or plant response. Do you agree with these revisions? If not, please explain in the comment area below.**

Summary Consideration: The majority of industry agreed with the revised language to make it clear that technically justified units were limited to units that meet the NERC Registry criteria thresholds and that "technical justification" is defined by demonstrating that the simulated unit or plant response does not match the measured unit or plant response. No modifications were made to the draft standard as a result of industry comments for Question 2.

Organization	Yes or No	Question 2 Comment
Tennessee Valley Authority	No	1. The GVSDT had good intentions by having a very short requirement. However, I am not sure what the intent is. A few more descriptive words would help greatly.
Response: Thank you for your review. Please note that the modification of language was made to the Applicability section.		
Exelon Corporation and its affiliates	No	Applicability Section 4.2.4 currently states "A technically justified2 unit that meets NERC registry criteria and is requested by the Transmission Planner." With the reference footnote stating "Technical justification is achieved by the Transmission Planner demonstrating that the simulated unit or plant response does not match the measured unit or plant response."This intended applicability is confusing and implies that the Transmission Planner has the discretion to decide applicability if a previously exempted unit does not meet Transmission Planner decided criteria. Exelon suggests that this be deleted in its entirety. If the GVSDT intent is to pull in other generating units below the MVA threshold criteria based on Transmission Planner discretion, then that should be factored into Applicability Sections 4.2.1 through 4.2.3. In addition, if Section 4.2.4 is also written to negate an exemption based on Transmission Planner discretion then that provision should be factored into

Organization	Yes or No	Question 2 Comment
		Attachment 1 and not into the applicability section.
Response: The GVSDT thanks you for your comment. The associated Requirement R5 does allow the TP a means to pursue additional model information if the model's predicted response does not match the actual equipment response. The SDT believes this is a reasonable way to allow the TP to pursue model information in the rare instances where there is an issue with a model that is not part of the base applicability. Additionally, the SDT has clarified Section 4.2.4 in the Applicability Section as follows: "A technically justified unit that meets NERC registry criteria but is not otherwise included in the above Applicability sections 4.2.1, 4.2.2, or 4.2.3 and is requested by the Transmission Planner."		
ACES Power Marketing Standards Collaborators	No	Because NERC and the Regional Entities do not maintain a public list of units that meet the "NERC registry criteria," it is impossible for the Transmission Planner to know for which set of units it may submit a technical justification per R5 and applicability section 4.2.4. The NERC ROP Appendix 5B, Statement of Compliance Registry criteria III.c.1, III.c.2 and III.c.3 each represent fairly "bright lines," where the TP can deduce which units meet these criteria. However, criterion III.c.4 is amorphous and notes on the page 11 of the document give NERC flexibility to deviate from the criteria anyway. Thus, we request that the drafting team either clarify that the "NERC registry criteria" in applicability section 4.2.4 is intended to mean criteria III.c.1, III.c.2 and III.c.3 in section III(c) of Appendix 5B - Statement of Compliance Registry Criteria or that the SDT work with NERC staff to determine how the TP may get a list of units that meet criterion III.c.4 and Note 1.
Response: The GVSDT thanks you for your comment. The intent of the verbiage is that all four criteria (III.c.1, III.c.2, III.c.3, and III.c.4) apply in combination with proof that the unit actual response does not match the model predicted response. In order to find out if a unit that is not otherwise meets the thresholds of III.c.1 – III.c.3 is included (per III.c.4), the team suggests that the applicable Transmission Planner can either check with the Region or NERC.		
Cowlitz PUD	No	Cowlitz is unsure if it is possible to accurately model generation such that modeling software will be able to predict actual plant response to a disturbance. The Standard may create a never ending circle of requests from the TP for improved modeling data. Cowlitz understands that modeling software is still in its infancy, and

Organization	Yes or No	Question 2 Comment
		more research and testing is needed to explore the boundaries between achievable modeling and where unrealistic goals exist.
Response: The GVSDT thanks you for your comment. Excitation control system model verification is well established and documented. Some of those documents are referenced in Section G of the standard, including IEEE 421.2 Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems. The acceptable models referenced in Requirement 1 will predominately consist of standard library models included in software manufacturer dynamic simulation packages and are well known and understood – many are models developed by IEEE. Information on the transmission system beyond the point of interconnection is not required. EPRI has developed software which supports non invasive ambient monitoring for model verification that is successfully being used by a number of entities. Other developers have also developed similar software. While it is true that many generators do not currently have necessary expertise, this expertise can be developed or hired. Proper software can be purchased to analyze the modeled response – utility grade dynamic simulation software used by Transmission Planners for regional and inter-regional studies does not have to be purchased. This standard has already undergone a NERC field test in the Summer of 2007 – one of the conclusions was that performing the activities specified in the draft standard will improve accuracy of the exciter model used in dynamic simulation. Entities from four regions participated, and all successfully completed the field test which validated that performing the activities specified in the draft standard will improve accuracy of the exciter model used in dynamic simulation.		
PPL Corporation NERC Registered Affiliates	No	It appears that without the word "and" in 4.2.4, this criterion of using NERC registration criteria would "trump" all the other interconnection requirements above. But, with the word "and" it indicates that any of the smaller registered units or blackstart resources would only be included in this standard if the Transmission Planner requires. The term “technically justified” in para. 4.2.4 on p.3 and in R5 is too vague, in that the degree of actual-vs-predicted mismatch triggering MOD-026-1 applicability is not specified. It is also not clear how this comparison is to be made if the Facility did not have to provide a MOD-026 model in the first place. In any event the wording of the R5 Violation Severity Levels should be modified to start the clock only after agreement has been reached that a request is technically justified.
Response: The GVSDT thanks you for your comment. The associated Requirement R5 does allow the TP a means to pursue		

Organization	Yes or No	Question 2 Comment
additional model information if the model's predicted response does not match the actual equipment response. Models do exist for these units through the processes defined in MOD-012 and 013, though they may not have been verified. The SDT believes this is a reasonable way to allow the TP to pursue model information in the rare instances where there is an issue with a model that is not part of the base applicability. Regarding the desire for criteria for mismatch, the standard states "what is required" but not "how to accomplish what is required." The SDT considered ways to quantify a method for evaluating how well the equipment's measured response matches the model's predicted response for this and other requirements. However, a generally accepted technique or criteria for making this quantitative assessment does not exist. The SDT believes use of the term "match" is appropriate because the Webster's dictionary defines "match" as something that is equal or similar to another. The SDT believes the existing wording of the VSL for R5 regarding when the clock starts is fair for all stakeholders and provides a well-defined and measurable initiation point. Also, the SDT believes that the activities described in R5 will rarely occur. One reason why this will rarely occur is because the only units that could be subjected to this requirement are those which are above the thresholds in the NERC Registry Criteria but are below the thresholds specified in the Applicability (Section 4). When they do occur, if the Transmission Planner obtains the recording of an event and subsequently perform a post mortem analysis and the results show that the response of the actual equipment does not match the predicted response of the model, the SDT believes that there will be no doubt that the unit fits the requirement of being declared "technically justified." If a fundamental error occurs that is discovered in the process, then the Transmission Planner will have no choice but to promptly remove their request (i.e., as there is not sustainable evidence that the unit meets the "technically justified" criteria).		
Oncor Electric Delivery Company	No	Oncor does not support the position that the TP is applicable for this standard. In the ERCOT Interconnection, Section 3 and Section 5 of the ERCOT Nodal Operating Guides prescribes the ERCOT ISO to request and receive generation unit performance data, not the TP. For MOD-026-1 Section 4.2.4, Oncor takes the position that it is the decision of the PA not the TP who determines the basis for NERC applicability.Oncor takes the position that a regional variance be granted for the ERCOT Interconnection such that the applicability determination in Section 4.2.4, be the responsibility of the PA only be the only requestor and receiver of unit performance data to support Section 3 and Section 5 of the ERCOT Nodal Operating Guides.

Organization	Yes or No	Question 2 Comment
Response: The GVSDT thanks you for your comments. Regarding the responsibilities assigned to the Transmission Planner in the draft standard, the SDT believes standard language lines up well with the vast majority of entity business practices in effect regarding the interactions between generation and transmission entities when collaborating on generator dynamic models. There are defined NERC processes outside the GV SDT effort where entities can request a regional variance. Alternatively, the Transmission Planner could delegate the responsibility to another such as its Planning Authority.		
ReliabilityFirst	No	ReliabilityFirst believes there is a major disconnect/flaw between the Applicability Section (4.2. Facilities) and Requirement R2, part 2.1. This major flaw will create confusion on which generating units are required to be verified per the standard. ReliabilityFirst offers the following comments for consideration:1. Requirements R2, Part 2.1 - There is a clear disconnect between the Applicability section of the standard (i.e. individual units/plants greater than 100MVA - Eastern or Quebec Interconnections) and Requirements R2, Part 2.1 which requires"... Verification of an individual unit less than 20 MVA." Based on the Applicability section, units less than 20 MVA are not applicable under this standard. Furthermore, units under 20 MVA do not fall under the NERC Statement of Compliance Registry Criteria as criteria for registration purposes for GOs and GOPs. **Response: The intent of the SDT is to allow the model verification expert to use any combination of individual or aggregate models in the verification of plants. The SDT has modified the applicable portion of Part 2.1 to read: "Verification for individual units rated less than 20 MVA (gross nameplate rating) in a generating plant (per Section 4.2.1.2, 4.2.2.2, or 4.2.3.2) may be performed using either individual unit or aggregate unit model(s) or both."** 2. Applicability Section 4.2. Facilities - ReliabilityFirst thanks the SDT for their justification for the 100 MVA threshold, but still believes that the Applicability should be consistent with the NERC Statement of Compliance Registry Criteria generator thresholds (i.e. 20 MVA or 75 MVA aggregate connected to the BES). Even though the 100 MVA threshold covers 80% of the connected MVA or greater for each Interconnection (in aggregate), depending on the geographic location (within the

Organization	Yes or No	Question 2 Comment
		BES), that value may be much less. For example, if there is a certain load pocket in which the majority of the connected generation is lest that 100 MVA, the dynamic models would not be required to be verified per this standard. Thus not having verified accurate dynamic models for this specific location could hinder the reliability of the BES. ReliabilityFirst recommends changing the Applicability section to be consistent with the NERC Statement of Compliance Registry Criteria generator thresholds (i.e. 20 MVA or 75 MVA aggregate connected to the BES). **Response: As discussed in the Comment Form with the first posting of the draft MOD-026 standard, the SDT considered the extent of the facilities to be verified and how to reflect this in the "applicability" of this proposed standard. As a basis, the SDT recognized that the excitation system models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the Field Test, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the exciter models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA thresholds corresponding to 80% of connected MVA or greater for each Interconnection are proposed. It is recognized that certain boundaries within an interconnection, such as BA boundaries, may have more or less than 80% of the connected MVA.** **The SDT further believes that a minimum unit interconnection of >100 kV, consistent with the Compliance Registry Guidelines, is appropriate. Finally, the SDT believes that the standard should apply to units with a capacity factor such that they are on-line 400 hours or greater a year. The SDT believes that these three applicability thresholds will result in substantial accuracy improvement to the excitation models and associated Reliability-based limits determined by dynamic simulations, while not unduly mandating costly and time consuming verification**

Organization	Yes or No	Question 2 Comment
		efforts. Footnote 4 (footnote 2 in the current draft) is intended to allow the Transmission Planner to request model information, possibly leading to model verification, for units which fall within the NERC Compliance Registry but are not of the base Applicability of this proposed standard. Also, the SDT does recognize that Regional variances can be considered if a Region desires to include additional unit MVA in this standard.
Response: The GVSDT thanks you for your comments. Please see responses above.		
Cogentrix Energy	No	The term “technically justified” in para. 4.2.4 on p.3 and in R5 is too vague, in that thedegree of actual-vs.-predicted mismatch triggering MOD-026-1 applicability is not specified.It is also not clear how this comparison is to be made if the Facility did not have to provide aMOD-026 model in the first place. In any event the wording of the R5 Violation SeverityLevels should be modified to start the clock only after agreement has been reached that arequest is technically justified.
Response: The GVSDT thanks you for your comments. The associated Requirement R5 does allow the TP a means to pursue additional model information if the model’s predicted response does not match the actual equipment response. Models do exist for these units through the processes defined in MOD-012 and 013, though they may not have been verified. The SDT believes this is a reasonable way to allow the TP to pursue model information in the rare instances where there is an issue with a model that is not part of the base applicability. Regarding the desire for criteria for mismatch, the standard states “what is required” but not “how to accomplish what is required.” The SDT considered ways to quantify a method for evaluating how well the equipment’s measured response matches the model’s predicted response for this and other requirements. However, a generally accepted technique or criteria for making this quantitative assessment does not exist. The SDT believes use of the term “match” is appropriate because the Webster’s dictionary defines “match” as something that is equal or similar to another. **The SDT believes the existing wording of the VSL for R5 regarding when the clock starts is fair for all stakeholders and provides a well-defined and measurable initiation point. Also, the SDT believes that the activities described in R5 will rarely occur. One reason why this will rarely occur is because the only units that could be subjected to this requirement are those which are above the thresholds in the NERC Registry Criteria but are below the thresholds specified in the Applicability (Section 4). When they do occur, if the Transmission Planner obtains the recording of an event and subsequently perform a post mortem analysis and the results show that the response of the actual equipment does not match the predicted response of the model, the SDT believes**		

Organization	Yes or No	Question 2 Comment
that there will be no doubt that the unit fits the requirement of being declared "technically justified." If a fundamental error occurs that is discovered in the process, then the Transmission Planner will have no choice but to promptly withdraw its request (i.e., as there is not sustainable evidence that the unit meets the "technically justified" criteria).		
Wisconsin Electric Power Company	No	We propose that the requirements for a "technically justified unit" must also include the technical reasons why the unit under consideration is critical to the reliability of the BES.
Response: The GVSDT thanks you for your comment. Regarding provision of a reason the unit is critical to reliability, R5 has undergone several modifications around this point. The SDT believes the existing R5 language strikes the best compromise to equitably satisfy all stakeholders as it allows Transmission Planners a way to request revised model data or a model verification.		
ISO-New England	No	This means that the Transmission Planner can only call for verification following a system event. It is counter to reliability to have to wait for an event to occur to then request verification. The footnote should be revised to include wording for the Transmission Planner to demonstrate an effect on the BES. Certain generators under 100 MVA could affect the BES and with this language verification could then take place.
Response: The GVSDT thanks you for your comments. The associated Requirement R5 does allow the TP a means to pursue additional model information if the model's predicted response does not match the actual equipment response. The SDT believes this is a reasonable way to allow the TP to pursue model information in the rare instances where there is an issue with a model that is not part of the base applicability. **Regarding provision of wording for the Transmission Planner to demonstrate an effect on the BES, R5 has undergone several modifications around this point. The SDT believes the existing R5 language strikes the best compromise to equitably satisfy all stakeholders as it allows Transmission Planners a way to request revised model data or a model verification for models that meet or exceed the NERC registry criteria thresholds but is below the standard's base applicability.**		
FirstEnergy	Yes	1. Although we agree with the footnote definition for "technical justification", we would like the term "match" be replaced with "simulates or represents". We feel

Organization	Yes or No	Question 2 Comment
		that these terms give more interpretation when comparing. 2. While we agree that a threshold for unit verification is appropriate, we are not clear as to why there would be different threshold for each Interconnection. The SDT should include a Guidelines and Technical Basis section that explains the geographical differences.
Response: The GVSDT thanks you for your comments. **1: The SDT believes use of the term "match" is appropriate because the Webster's dictionary defines "match" as something that is equal or similar to another.** **2: The individual unit and aggregate plant ratings used in the applicability section were carefully derived for each Interconnection to capture validation of approximately 80% of the total installed base in that region. The selection of these applicability requirements intend to strike the most reasonable balance between managing the costs to perform tests and validation vs. ultimately assuring that the reliability of the Bulk System is not compromised due to poor models. This concept has been validated through industry comments from prior postings of the draft standard.**		
Manitoba Hydro	Yes	Although Manitoba Hydro agrees with the concept proposed, it is difficult or sometimes impossible to get an exact match between simulated and measured responses. The drafting team should allow for some engineering judgment (for example, if the responses are within 5-10% of each other, the model could be considered to be a reasonable representation).
Response: The GVSDT thanks you for your comments. Regarding the use of the term "match," there is no explicit requirement for quality of match between test and simulation in the determination of a technically justified unit. Regarding the second half of the comment beginning with a desire for acceptance criteria, the standard states "what is required" but not "how to accomplish what is required." The SDT considered ways to quantify a method for evaluating how well the equipment's measured response matches the model's predicted response for this and other requirements. However, a generally accepted technique or criteria for making this quantitative assessment does not exist. **Finally, in part, the SDT believes use of the term "match" is appropriate because the Webster's dictionary defines "match" as**		

Organization	Yes or No	Question 2 Comment
something that is equal or similar to another.		
Dominion	Yes	Dominion agrees with this change; however, is concerned with the phrase "demonstrating that the simulated unit or plant response does not match the measured unit or plant response." The use of the word "match" implies that the simulated response and measures response must be exact, when in fact this will not likely be the case. This language in section 4.2.4 (and other sections) should allow for acceptable variation so compliance can be properly achieved and demonstrated.
Response: The GVSDT thanks you for your comments. Regarding the use of the term "match" to describe the expectations of model verification by the Generator Owner, there is no explicit requirement for quality of match between test and simulation in the determination of a technically justified unit. Regarding the second half of the comment beginning with a desire for acceptance criteria, the standard states "what is required" but not "how to accomplish what is required." The SDT considered ways to quantify a method for evaluating how well the equipment's measured response matches the model's predicted response for this and other requirements. However, a generally accepted technique or criteria for making this quantitative assessment does not exist. **Finally, in part, the SDT believes use of the term "match" is appropriate because the Webster's dictionary defines "match" as something that is equal or similar to another.**		
Idaho Power Company	Yes	Idaho Power System Planning agrees with the revisions made in Section 4.2.4.Idaho Power Generator Owner- The phrase "units that meet the NERC Registry Criteria" has no meaning, since entities and not units are placed on the NERC registry. In addition, demonstrating that a simulated response does not match a measured response is not sufficient technical justification. Additional, technical justification should include demonstration that the different response materially impacts system studes. Additionally, allowing only one year for submission of test results following a technical justification is unreasonable, 5 or 10 years to match the initial implementation time period is more reasonable from the Generator Owner perspective for appropriately planning and scheduling the outage time and work.
Response: The GVSDT thanks you for your comments. The SDT believes the language regarding units that meet NERC Registry		

Organization	Yes or No	Question 2 Comment
(emphasis) "Criteria" is clear – as criteria is not referring to entities that may (or may not) be required to register in the NERC Registry as a Generator Owner. Regarding provision of a reason the different response materially impacts system studies, R5 has undergone several modifications around this point. The SDT believes the existing R5 language strikes the best compromise to equitably satisfy all stakeholders as it allows Transmission Planners a way to request revised model data or a model verification for models that meet or exceed the NERC registry criteria thresholds but is below the standard's base applicability. Also, the SDT believes one year is sufficient time to verify the model. Online step in voltage tests or ambient monitoring are techniques which do not require unit outages to implement.		
Ingleside Cogeneration LP (Voting entity Occidental Chemical Corporation)	Yes	In general, Ingleside Cogeneration LP believes that a good working relationship between the Generator Owner and Transmission Planner includes a reasonable justification for any request that requires time and expense on the part of the other.
Response: The GVSDT thanks you for your comment.		
Texas Reliability Entity	Yes	Should Blackstart units have a specific inclusion as an "applicable unit", regardless of capacity factor or "technical justification"?
Response: The GVSDT thanks you for your comments. The SDT has not included Blackstart units in the base Applicability.		
Southwest Power Pool Reliability Standards Development Team	Yes	
Bonneville Power Administration	Yes	
Duke Energy	Yes	
Luminant	Yes	
pacificorp	Yes	

Organization	Yes or No	Question 2 Comment
Southern Company	Yes	
Dynegy	Yes	
TransAlta Centralia Generation LLC	Yes	
PSEG	Yes	
Xcel Energy	Yes	
American Transmission Company	Yes	
Independent Electricity System Operator	Yes	
Northeast Utilities	Yes	
South Carolina Electric and Gas	Yes	
Ameren	Yes	
Georgia Transmission Corporation	Yes	

3. Do you have any other comment, not expressed in questions above, for the GVSDT?

Summary Consideration:

The following modifications were made to the standard in response to industry comments to Question 3:

In the Effective Date section 5.3, the word “thirty” after the word “quarter” was inserted in the standard by mistake. As such, the SDT removed the word “thirty.”

The wording, “… or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities …” in Section 5.1 was moved to right after “approved by applicable regulatory authorities …” And that same wording was moved to right after, “… following applicable regulatory approval …” in Sections 5.2 to 5.4. Also, the same phrase was appended to each of the four bullets in the Effective Dates Section, “In those jurisdictions where regulatory approval is required:” of the Implementation Plan right after, “… following applicable regulatory approval …”

The SDT has clarified Section 4.2.4 in the Applicability Section as follows: “A technically justified unit that meets NERC registry criteria but is not otherwise included in the above Applicability sections 4.2.1, 4.2.2, or 4.2.3 and is requested by the Transmission Planner.”

The SDT has refined the applicable portion of Part 2.1 to read: “Verification for individual units rated less than 20 MVA (gross nameplate rating) in a generating plant (per Section 4.2.1.2, 4.2.2.2, or 4.2.3.2) may be performed using either individual unit or aggregate unit model(s) or both.” This ties the requirement to the applicability of the standard per stakeholder request.

Refined sub part 2.1.2 to read: “Manufacturer, model number (if available), and type of the excitation control system including, but not limited to static, AC brushless, DC rotating, and/or the plant volt/var control function (if installed).”

Clarified that the response by the Transmission Planner to the Generator Owner concerning the results of testing the model useability is required to be a written response (R6). Also, for ease of reading, moved the last sentence in the requirement to after the parts.

Revised the first sentence in R1 to read: “Each Transmission Planner shall provide the following requested information to the Generator Owner within 90 calendar days of receiving a written request.”

Included the term “impedance compensation” to Footnote 1 in the description of what constitutes a excitation control system for synchronous machines.

Organization	Question 3 Comment

Organization	Question 3 Comment
ACES Power Marketing Standards Collaborators	(1) Thank you for modifying the applicability section. It is greatly improved and is much clearer than the previous version. However, we believe there are a few additional minor refinements necessary. First, generators can be and are part of the Bulk Electric System. Thus, we suggest changing "Facilities that are directly connected to the Bulk Electric System (BES)" to "generation Facilities that are part of the Bulk Electric System." Otherwise, there might be some confusion if the drafting team intends to draw in generators that are not part of the BES. Second, we find the wording "will be collectively referred as an 'applicable unit' that meet the following" confusing. We think the intent was to clarify that an applicable unit is one that is part of the BES and meets criteria established in section 4.2.1, 4.2.2, 4.2.3, and 4.2.4. However, we think the inclusion of the "will be collectively referred as an 'applicable unit'" is superfluous. Because the section is the applicability section, we think this language could be struck for clarity and the applicable units will be understood to mean those that meet the criteria in section 4.2. As an alternative, the drafting team could explain in a footnote what they mean by the term applicable unit. Third, with the two proposed changes, we think the final wording of section 4.2 after the opening clause should be "generation Facilities that are part of the Bulk Electric System (BES) that meet the following criteria:". **Response: The SDT believe that the term "directly connected to the Bulk Electric System" is appropriate as that is the verbiage used in the Statement of Compliance Registry Criteria. The reason for utilizing the term "applicable unit" is that it is used in other portions of the standard and allows a simple reference to the base Applicability for each Interconnection.** (2) In requirement R2, please change "for each applicable unit" to "for each of its applicable units." This is the previous wording and is more correct. The current wording literally says that the GO must provide a verified model for each applicable unit including those it does not own. After all any unit that meets applicability criteria including those owned by other GOs would be an applicable unit. **Response: The SDT believe that the use of the phrase "for each applicable unit" being placed in a sentence immediately after the phrase "Each Generator Owner shall provide" clearly conveys the intent that the applicable units being referenced are those which belong to each Generator Owner. Also, note that the term "applicable unit" is defined for the content of this standard in**

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	the Applicability section. (3) Please specify in M1 that a Transmission Planner may also provide an attestation that no such request was received if this is the case. Use of attestation that an event did not occur is established as an acceptable form of evidence in CAN-0030. Furthermore, precedent has been set in the use of attestations in measures in FAC-003-2 M1 and M2. **Response: As you stated, compliance recognizes that an attestation is an acceptable form of evidence. As such, including that in the Measures is repetitive.** (4) We continue to believe that the examples provided in the comment form should be included in the standard. Please create an Application Guidelines or Guidelines and Technical Basis section in the standard and add them. This has become common practice with developing standards. We do not understand why the drafting team would not want to retain such information that helps readers understand the standard and that has already been developed. Furthermore, it would make it easier for commenters to see what has changed in the examples because a red-line of the standard is required. Because the examples were contained in the comment form this time and during the previous posting, it is not easy to deduce the changes because there is no red-line. If the examples are not included in the standard, please provide more explanation than was provided during the last response to comments which was that it is not appropriate to include the examples. We do not understand why it is not appropriate. **Response: The examples provided were for clarification, and the SDT does not believe that all possible scenarios are considered. The SDT does not believe the examples are appropriate for inclusion in the standard itself. Also, the sections that you referred to as being an appropriate location to include the examples are not part of this standard's format. We believe that majority of stakeholders do not have a desire to include these examples in the standard.** (5) We disagree with the need to retain the latest model verification evidence under Requirement R2 and M2. First, this is not consistent with the Section 3.1.4.2 of Appendix 3c to the NERC Rules of Procedure section which states that the audit will cover the period from the day after the last compliance audit to the end date of the current compliance audit. Since the audit cycle for a GO is six years and the model verification period is 10 years, the GO will have to retain data past its prior

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	audit period. Furthermore, the auditor will have already had an opportunity to review the model verification data during the last audit. Presumably, if they did not find any compliance violations, there should not be a need to review this data again. Thus, the data retention should not exceed the six year audit cycle. **The SDT believes that once the recurring 10-year periodicity is established, that the Generator Owner has to maintain records regarding the last verification to be able to demonstrate that they conducted a valid verification within the last 10 years. As written, this follows the Data Retention guidelines. The alternative is to shorten the periodicity to six years. However, as confirmed by industry comments in prior postings, the SDT believe that the 10-year periodicity has overwhelming industry consensus.** (6) How will mothballed units be handled in Attachment 1? If a mothballed unit is returned to service which row in Attachment 1 applies? What if the unit was mothballed before the effective date and returned to service after all stages of the effective dates? What if it was mothballed after an initial verification? How does this affect the next verification date? **Response: If the unit was mothballed before the effective date of the standard, upon coming out of retirements, Row 3 would be applicable. In all cases, after the initial verification, at a minimum, the 10-year periodicity would apply. Thus, if a unit was mothballed for years 5 – 7, the model would still need to be verified with the documentation and data to the Transmission Planner at year 10.**
Response: The GVSDT thanks you for your comments. Please see responses above.	
Ameren	(1)We request that papers listed in the references section of the standard are made readily available on the NERC website. **Response: The papers are readily available as documented in the references. Due to copyright limitations, many of the documents cannot be made available on the NERC website.** (2)There appears to be an extra word “thirty” in both redline and clean versions of the standard under section 5.3 of the Effective Date section of the draft standard.

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	Response: The extra "thirty" has been removed in the current draft of the standard. (3)As we understand, part of R1 is for the Transmission Planner to provide instructions on how to obtain the list of acceptable model types for use in dynamic simulations. In this regard, we ask the SDT if this would preclude the use of user-written models? **Response: The standard does not preclude user written models however the model must be on the list approved by the Transmission Planner.** (4)We still have serious concerns about compliance with new MOD-026-1 while compliance with MOD-012-0 and MOD-013-1 is still in effect. We appreciate the SDT considering our comments on this issue in the last draft, but we still disagree about the potential conflicts for the following reasons:(a)The reporting requirements to comply with MOD-012 are dependent upon the data requirements and reporting procedures put in place by their Regional Entity as mandated by MOD-013. This does not provide consistency across the country. (b)We take data reporting under MOD-012 very seriously and incorporate testing in our program to ensure the data is accurate. Consequently, our reporting and compliance with MOD-012 does involve generator testing on a 5 year basis. (c)Any GO that has implemented a MOD-012 compliance program that involves testing that cannot perfectly synchronize with the 10 year testing in this draft of MOD-026 will have a significant burden in scheduling generator testing to satisfy both standards.(5)We strongly request the SDT seriously consider incorporating the current MOD-012/MOD-013 submittal requirements within MOD-026. This will synchronize the reporting and verification requirements and help minimize the resource burden of compliance with both efforts. At the same time it will create consistency across the country. **Response: MOD-012 and MOD-013 contain data submittal requirements that require submission of the latest dynamic model data for generator, excitation system, voltage regulator, power system stabilizer and turbine-governor. MOD-026 requires model verification including submittal of the verified excitation system dynamic model and data.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
Idaho Power Company	1) Technical Justification of units based solely on a simulated response not matching recorded

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	response is insufficient. Technical Justification needs to include evidence that the difference in response has a material effect on the conclusions of the relevant system studies. **Response: Regarding provision to include evidence that the difference in response has a material effect on the conclusions of the relevant system studies, R5 has undergone several modifications around this point. The SDT believes the existing R5 language strikes the best compromise to equitably satisfy all stakeholders as it allows Transmission Planners a way to request revised model data or a model verification for models that meet or exceed the NERC registry criteria thresholds but is below the standard's base applicability.** 2) Requiring each Transmission Planner to maintain a list of acceptable models, and then requiring Generator Owners to submit data according to those models is unreasonable. The list of acceptable models needs to be at least regional, if not continent-wide. In addition, some required longevity needs to be specified to allow Generator Owners to appropriately plan and perform the verification work. **Response: Since the Transmission Planner is the user of the models, the models must be acceptable to the Transmission Planner in order to be deemed useful. The list of models in the vast majority of the time will be models included in major manufacturer dynamic simulation software vendor libraries and they have a high correlation with other dynamic simulation software vendor model libraries and those developed via IEEE.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
Texas Reliability Entity	1) Considering the proposed new BES definition and the Guidance Document, there may be confusion in determining if a generator is "directly connected" to the BES. Please consider reviewing the language to see if it should instead say "included in" the BES. Note that a BES generator can be connected to the BES by non-BES elements, and arguably not "directly connected" to the BES. See, for example, figures E1-4 and E1-6 in the BES Definition Guidance Document. **Response: The SDT believe that the term "directly connected to the Bulk Electric System" is appropriate as that is the verbiage used in the Statement of Compliance Registry Criteria.** 2) TRE recommends changing to "Planning Authority or Transmission Planner" in the Functional

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	Entities in Section 4.1.2 instead of "Transmission Planner". This change should be duplicated in the requirements. The change may be needed since the Planning Authority or the Transmission Planner may have the responsibility for modeling the generation data provided by the Generator Owners. **Response: The reporting structure of the standard has been vetted through multiple comment periods and the GVSDT believes that the Transmission Planner is the appropriate entity. The GVSDT believes that we have achieved stakeholder consensus on the current language of the standard.** 3) The timelines are generally too long, which will result in stale, incorrect and generic data being utilized in modeling systems. Consider shortening timeframes. **Response: The timelines contained in the standard has been vetted through multiple comment periods and the GVSDT believes that we have achieved stakeholder consensus on the current language of the standard.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
Wisconsin Electric Power Company	1. In 4.2.1.2, the use of the term "directly connected at a common BES bus" suggests that wind farms are not applicable facilities, since wind generators are typically directly connected to a non-BES bus (e.g. 34.5 kv). We suggest that the applicability to wind farms be clarified more explicitly. **Response: The SDT believe that the term "directly connected to the Bulk Electric System" is appropriate as that is the verbiage used in the Statement of Compliance Registry Criteria.** 2. In R1, the present wording allows for the TP to provide only one of the three types of data, even if the GO requested all three. We suggest removing the wording, "one or more of". **Response: Based on your comment, the SDT revised the first sentence in R1 to read: "Each Transmission Planner shall provide the following requested information to the Generator Owner within 90 calendar days of receiving a written request:"** 3. In R1, the present requirement is for the TP to provide instructions to the GO on how to obtain the acceptable models and associated block diagrams and data. We believe that since the TP is very familiar with this data and the GO may not be, it is far simpler and efficient for the TP to provide the

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	actual data on request, not just the instructions on how to obtain it. **Response: Transmission Planners ordinarily have license agreements that do not permit them to provide the block diagrams and data sheets directly to the generator owner. However, the software manufacturers have indicated that they will make accommodations so that Generator Owners without software licenses can receive the block diagrams and data sheets.** 4. In R2.1.1, the GO is required to have documentation comparing the "model response" to the "recorded response", in this case Voltage vs. Time. First, to determine the model response requires the ability to run dynamic studies. Generally the GO does not have the simulation capability or the subject matter experts required to perform dynamic system studies. It would seem that the intent of this requirement is that the GO must expend considerable resources to gain this capability, either internally or by other means. Is this the intent of the SDT? **Response: Excitation control system model verification is well established and documented. Some of those documents are referenced in Section G of the standard, including IEEE 421.2 Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems. The acceptable models referenced in Requirement 1 will predominately consist of standard library models included in software manufacturer dynamic simulation packages and are well known and understood – many are models developed by IEEE. Information on the transmission system beyond the point of interconnection is not required. EPRI has developed software which supports non invasive ambient monitoring for model verification that is successfully being used by a number of entities. Other developers have also developed similar software. While it is true that many generators do not currently have necessary expertise, this expertise can be developed or hired - or the Generator Owner can enter into agreements with its Transmission Planner, though the Generator Owner will still be responsible from a compliance perspective. Proper software can be purchased to analyze the modeled response – utility grade dynamic simulation software used by Transmission Planners for regional and inter-regional studies does not have to be purchased.** 5. In R3, the requirements for the written response to the TP need clarification. The term "either" would suggest there are two possible responses. However, there appear to be three possible responses. We suggest there needs to be a 4th possible response option for the GO, for the GO to

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	initiate contact with the TP to schedule a meeting to discuss the technical issues with the model. The necessary collaboration between the GO and TP to understand the model deficiencies will require time, thus may require more than the 90 days to reconcile the model issues. 120 days is suggested. **Response: The SDT believes that the sentence containing the word "either" clearly lists the three written response options afforded to the Generator Owner. Merriam-Webster dictionary defines "either" when used as a conjunction as, "Used as a function word before two or more coordinate words, phrases, or clauses joined usually by or to indicate that what immediately follows is the first of two or more alternatives." The SDT believes that 90 days is sufficient time to for the Generator Owner to discuss model issues with the Transmission Planner. The SDT believes all parties will be equally motivated to work through model verification issues.** 6. In Section 5 Effective Dates: The considerable time and resources needed to get up to speed with model verification suggests there needs to be more time allowed in the earlier phases of the compliance timeline. We suggest using 20 percent in 4 years, 40 percent in 6 years, and 100 percent in 10 years. **Response: The SDT believes the effective dates have been well vetted in previous postings and that we have achieved stakeholder consensus on the current language of the standard.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
Dynegy	1. It's not clear what the difference is between R3 and R5. Suggest combining these into one Requirement. MOD-027-1 which also requires model validation does not have a Requirement similar to R5.2. Requirement 2.1.1 does not state how much of a step change is required when testing the exciter controls. A commonly used step is 2% but this is not clear.
Response: The GVSDT thanks you for your comment. The peer review type activities in R3 are for units which have been verified per the standard, or the verification process is on-going, but there are potential issues regarding that verification process. The associated Requirement R5 does allow the TP a means to pursue additional model information if the model's predicted response does not match the actual equipment response for units that are above the threshold in the current NERC Registry Criteria but	

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below the standard's base Applicability MVA thresholds. The SDT believes this is a reasonable way to allow the TP to pursue model information in the rare instances where there is an issue with a model that is not part of the base applicability. Additionally, the SDT has clarified Section 4.2.4 in the Applicability Section as follows: "A technically justified unit that meets NERC registry criteria but is not otherwise included in the above Applicability sections 4.2.1, 4.2.2, or 4.2.3 and is requested by the Transmission Planner." Regarding step change magnitude to test the exciter controls, the SDT believes that the method used to verify the model should be determined by those doing the model verification. The testing expert will determine the voltage excursion magnitude to use during testing and other details regarding how to do the test.	
Essential Power, LLC	1. The standard is based on the assumption that it is possible to tune the acceptable models cited in R1 such that their predictions will match actual voltage and reactive power responses to system Disturbances. The yet-to-be-defined acceptable models may not be capable of achieving this goal, however, because standard excitation component models are inadequate to predict with high fidelity the generation system response that is the subject of MOD-026-1. Such models do not take into account, for example, equipment thermal capability limitations and the capping of reactive power output to respect aux bus voltage limits. The SDT is therefore asking for a considerable advancement in the excitation modeling state of the art, to be undertaken in parallel by the owners of every generation unit in North America. This is a doubly daunting task in that GOs often do not have any dynamic modeling software or expertise, much less the ability to invent something new, because the present approach to the subject is that GOs just provide the values of input parameters to the TP, which owns and runs models. Independent GOs (i.e. deregulated entities that are not part of a vertically-integrated utility) moreover do not have and cannot obtain information on the system outside the plant battery limits. This circumstance renders them unable to model the plant-T&D interactions associated with Disturbances, and independent GOs may therefore forever remain unable to develop model results that closely match actual Disturbance responses. The approach being taken in MOD-026-1 is consequently viewed as being technically infeasible for the present state of the art as well as unjustified in light of FERC's March 15, 2012 FFT Order to propose specific standards or requirements that should be revised or removed [or not enacted in the first place] due to having little effect on reliability or because of compliance burdens. The SDT should instead collaborate with industry associations (EPRI, IEEE, NAGF), equipment OEMs, and modeling services vendors to develop the right tools for the job, and put the new models through trial runs at several plants. These trials should be limited to data-collection means that can be non-invasively employed

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	(e.g. online voltage step-response tests, low-load rejection during normal stop events), and should lead to definition of specific testing means for definition of specific model parameters. The SDT should then put out for voting a standard requiring TOPs to own and run these models, and requiring GOs to provide them the appropriate input data, developed via the non-invasive means stated above. **Response: Excitation control system model verification is well established and documented. Some of those documents are referenced in Section G of the standard, including IEEE 421.2 Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems. The acceptable models referenced in Requirement 1 will predominately consist of standard library models included in software manufacturer dynamic simulation packages and are well known and understood – many are models developed by IEEE. Information on the transmission system beyond the point of interconnection is not required. EPRI has developed software which supports non invasive ambient monitoring for model verification that is successfully being used by a number of entities. Other developers have also developed similar software. While it is true that many generators do not currently have necessary expertise, this expertise can be developed or hired. Proper software can be purchased to analyze the modeled response – utility grade dynamic simulation software used by Transmission Planners for regional and inter-regional studies does not have to be purchased. This standard has already undergone a NERC field test in the Summer of 2007 – one of the conclusions was that performing the activities specified in the draft standard will improve accuracy of the exciter model used in dynamic simulation. Entities from four regions participated, and all successfully completed the field test which validated that performing the activities specified in the draft standard will improve accuracy of the exciter model used in dynamic simulation.** 2. There is presently no definition of the voltage excursion magnitude and intensity or the recording instrumentation sampling rate required for a valid verification event. There are also no specifics regarding how closely the model must match the recorded response or for what period of time, just a requirement that it be deemed “usable” by the TP. The SDT is asking for a blank check, and we cannot agree to regulations for which it is impossible to say at the time of balloting whether or not compliance can be achieved, let alone in a fashion that is justified per the FERC order cited above. Perceived shortcomings in these respects would presumably trigger the Transmission Planner

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	expression of concern described in R3, but it would be better to establish the rules up-front rather than addressing the matter only after a GO has attempted to comply with MOD-026 and been found lacking. It was stated in a 7/29/11 webinar that a signal-to-noise ratio of at least 5:1 is needed for a meaningful validation, but this criterion did not make it into the standard. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard through the previous comment periods. The SDT believes specifying a voltage excursion magnitude is prescriptive. The testing expert will determine the voltage excursion magnitude to use during testing. Also the SDT consciously avoided specifying the quality of match between model and test a) to avoid risk of being over-prescriptive and too restrictive and b) because an industry accepted quantification of "match" does not exist. The focus is solely on "what" is required, not "how" it's done.** 3. The term "rotational inertia" in R2.1.3 should be replaced with "inertia constant (H)," the rotational inertia divided by MVA rating, since this is the parameter of interest for stability studies. Either way, the obligation to conduct testing in this respect should be waived for units having an OEM-developed value and no modifications to the rotating components, since rotational inertia can be identified more precisely via calculation than by clocking a post-trip over speed excursion. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard through the previous comment periods.** 4. The term "technically justified" in para. 4.2.4 on p.3 and in R5 is too vague, in that the degree of actual-vs.-predicted mismatch triggering MOD-026-1 applicability is not specified. It is also not clear how this comparison is to be made if the Facility did not have to provide a MOD-026 model in the first place. In any event the wording of the R5 Violation Severity Levels should be modified to start the clock only after agreement has been reached that a request is technically justified. **Response: The associated Requirement R5 does allow the TP a means to pursue additional model information if the model's predicted response does not match the actual equipment response. Models do exist for these units through the processes defined in MOD-012 and 013, though they may not have been verified. The SDT believes this is a reasonable way to allow the TP to pursue model information in the rare instances where there is an issue with a model that is not part of**

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	the base applicability. Regarding the desire for criteria for mismatch, the standard states "what is required" but not "how to accomplish what is required." The SDT considered ways to quantify a method for evaluating how well the equipment's measured response matches the model's predicted response for this and other requirements. However, a generally accepted technique or criteria for making this quantitative assessment does not exist. The SDT believes use of the term "match" is appropriate because the Webster's dictionary defines "match" as something that is equal or similar to another. **The SDT believes the existing wording of the VSL for R5 regarding when the clock starts is fair for all stakeholders and provides a well-defined and measurable initiation point. Also, the SDT believes that the activities described in R5 will rarely occur. One reason why this will rarely occur is because the only units that could be subjected to this requirement are those which are above the thresholds in the NERC Registry Criteria but are below the thresholds specified in the Applicability (Section 4). When they do occur, if the Transmission Planner obtains the recording of an event and subsequently perform a post mortem analysis and the results show that the response of the actual equipment does not match the predicted response of the model, the SDT believes that there will be no doubt that the unit fits the requirement of being declared "technically justified." If a fundamental error occurs that is discovered in the process, then the Transmission Planner will have no choice but to promptly remove their request (i.e., as there is not sustainable evidence that the unit meets the "technically justified" criteria).** We propose that the requirements for a "technically justified unit" must also include the technical reasons why the unit under consideration is critical to the reliability of the BES. **Response: Regarding provision of a reason the unit is critical to reliability, R5 has undergone several modifications around this point. The SDT believes the existing R5 language strikes the best compromise to equitably satisfy all stakeholders as it allows Transmission Planners a way to request revised model data or a model verification.** 5. The instruction in R4 to notify the TP, "within 180 calendar days of making changes that alter the system response is too vague, despite the attempted clarification in footnote #3, since many activities can have some degree of impact as noted above. Reportable thresholds regarding degree

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	of impact on system response and the expected duration are needed. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The SDT believes specifying reportable thresholds for an infinite number of possible permutations is not practical for a standard.** 6. Please add clarifying language to R5 to emphasize that this requirement is addressing units that meet the NERC registry criteria but are smaller than the MVA size specified in the applicability section. **Response: Thank you for pointing out the need to include further clarification. The SDT has clarified Section 4.2.4 in the Applicability Section as follows: "A technically justified unit that meets NERC registry criteria but is not otherwise included in the above Applicability sections 4.2.1, 4.2.2, or 4.2.3 and is requested by the Transmission Planner."** 7. Sub-requirement 2.1.4 is not clear - is this data the model block diagram and its parameters? If so, simply state that. **Response: The phrase "model structure" refers to a block diagram without parameter values, thus the SDT feels like the language in R2.1.4 is clear. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.** 8. We recommend removing the first element of the logical AND statement of Attachment 1 Row 4 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. A sister is a sister independent of the physical location. As long as the equipment is identical, the concept should be allowed to apply regardless of location. **Response: The SDT notes the general agreement among industry with using the proxy unit approach. The SDT respectfully maintains that the "same physical location" requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site walk down). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g., requirement for PSS in-service).**

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	9. The SDT should consider moving the capacity factor exemption information found in Attachment 1, row 7 into the applicability section. The applicability section should allow an entity to be able to determine if the standard applies to them and be able to determine the scope of the facilities affected. It is best for those impacted to immediately know which units are in the scope and not have to realize the scope from a detailed study of the table of Attachment 1. This would allow row 7 of Attachment 1 to be deleted. **Response: The SDT decided to place all the scenarios that effectively "exempt" otherwise applicable units in Attachment 1 for clarity. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
Cogentrix Energy	1. The standard is based on the assumption that it is possible to tune the acceptable models cited in R1 such that their predictions will match actual voltage and reactive power responses to system Disturbances. The yet-to-be-defined acceptable models may not be capable of achieving this goal, however, because standard excitation component modelsare inadequate to predict with high fidelity the generation system response that is the subject of MOD-026-1. Such models do not take into account, for example, equipment thermal capability limitations and the capping of reactive power output to respect aux bus voltage limits. The SDT is therefore asking for a considerable advancement in the excitation modeling state of the art, to be undertaken in parallel by the owners of every generation unit in North America. This is a doubly daunting task in that GOs often do not have any dynamic modeling software or expertise, much less the ability to invent something new, because the present approach to the subject is that GOs just provide the values of input parameters to the TP, which owns and runs models. Independent GOs (i.e. deregulated entities that are not part of a vertically-integrated utility)moreover do not have and cannot obtain information on the system outside the plant battery limits. This circumstance renders them unable to model the plant-T&D interactions associated with Disturbances, and independent GOs may therefore forever remain unable to develop model results that closely match actual Disturbance responses. The approach being taken in MOD-026-1 is consequently viewed as being technically infeasible for the present state of the art as well as unjustified in light of FERC's March 15,2012 FFT Order to propose specific

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	standards or requirements that should be revised or removed [or not enacted in the first place] due to having little effect on reliability or because of compliance burdens. The SDT should instead collaborate with industry associations (EPRI, IEEE, NAGF),equipment OEMs, and modeling services vendors to develop the right tools for the job, and put the new models through trial runs at several plants. These trials should be limited to data-collection means that can be non-invasively employed (e.g. online voltage step response tests, low-load rejection during normal stop events), and should lead to definition of specific testing means for definition of specific model parameters. The SDT should then put out for voting a standard requiring TOPs to own and run these models, and requiring GOs to provide them the appropriate input data, developed via the non-invasive means stated above. **Response: Excitation control system model verification is well established and documented. Some of those documents are referenced in Section G of the standard, including IEEE 421.2 Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems. The acceptable models referenced in Requirement 1 will predominately consist of standard library models included in software manufacturer dynamic simulation packages and are well known and understood – many are models developed by IEEE. Information on the transmission system beyond the point of interconnection is not required. EPRI has developed software which supports non invasive ambient monitoring for model verification that is successfully being used by a number of entities. Other developers have also developed similar software. While it is true that many generators do not currently have necessary expertise, this expertise can be developed or hired. Proper software can be purchased to analyze the modeled response – utility grade dynamic simulation software used by Transmission Planners for regional and inter-regional studies does not have to be purchased. This standard has already undergone a NERC field test in the Summer of 2007 – one of the conclusions was that performing the activities specified in the draft standard will improve accuracy of the exciter model used in dynamic simulation. Entities from four regions participated, and all successfully completed the field test which validated that performing the activities specified in the draft standard will improve accuracy of the exciter model used in dynamic simulation.** 2. There is presently no definition of the voltage excursion magnitude and intensity or therecording instrumentation sampling rate required for a valid verification event. There arealso no specifics

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	regarding how closely the model must match the recorded response or forwhat period of time, just a requirement that it be deemed “usable” by the TP. The SDT isasking for a blank check, and we cannot agree to regulations for which it is impossible tosay at the time of balloting whether or not compliance can be achieved, let alone in afashion that is justified per the FERC order cited above.Perceived shortcomings in these respects would presumably trigger the TransmissionPlanner expression of concern described in R3, but it would be better to establish the rulesPage 5 of 11up-front rather than addressing the matter only after a GO has attempted to comply withMOD-026 and been found lacking. It was stated in a 7/29/11 webinar that a signal-to-noiseratio of at least 5:1 is needed for a meaningful validation, but this criterion did not make itinto the standard. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The SDT believes specifying a voltage excursion magnitude is prescriptive. The testing expert will determine the voltage excursion magnitude to use during testing. Also the SDT consciously avoided specifying the quality of match between model and test a) to avoid risk of being over-prescriptive and too restrictive and b) because an industry accepted quantification of “match” does not exist. The focus is solely on “what” is required, not “how” it’s done.** 3. The term “rotational inertia” in R2.1.3 should be replaced with “inertia constant (H),” the rotational inertia divided by MVA rating, since this is the parameter of interest for stability studies. Either way, the obligation to conduct testing in this respect should be waived for units having an OEM-developed value and no modifications to the rotating components, since rotational inertia can be identified more precisely via calculation than by clocking a post-trip over speed excursion. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard.** 4. The term “technically justified” in para. 4.2.4 on p.3 and in R5 is too vague, in that the degree of actual-vs.-predicted mismatch triggering MOD-026-1 applicability is not specified. It is also not clear how this comparison is to be made if the Facility did not have to provide aMOD-026 model in the first place. In any event the wording of the R5 Violation Severity Levels should be modified to start the clock only after agreement has been reached that a request is technically justified.

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	Response: The associated Requirement R5 does allow the TP a means to pursue additional model information if the model's predicted response does not match the actual equipment response. Models do exist for these units through the processes defined in MOD-012 and 013, though they may not have been verified. The SDT believes this is a reasonable way to allow the TP to pursue model information in the rare instances where there is an issue with a model that is not part of the base applicability. Regarding the desire for criteria for mismatch, the standard states "what is required" but not "how to accomplish what is required." The SDT considered ways to quantify a method for evaluating how well the equipment's measured response matches the model's predicted response for this and other requirements. However, a generally accepted technique or criteria for making this quantitative assessment does not exist. The SDT believes use of the term "match" is appropriate because the Webster's dictionary defines "match" as something that is equal or similar to another. **The SDT believes the existing wording of the VSL for R5 regarding when the clock starts is fair for all stakeholders and provides a well-defined and measurable initiation point. Also, the SDT believes that the activities described in R5 will rarely occur. One reason why this will rarely occur is because the only units that could be subjected to this requirement are those which are above the thresholds in the NERC Registry Criteria but are below the thresholds specified in the Applicability (Section 4). When they do occur, if the Transmission Planner obtains the recording of an event and subsequently perform a post mortem analysis and the results show that the response of the actual equipment does not match the predicted response of the model, the SDT believes that there will be no doubt that the unit fits the requirement of being declared "technically justified". If a fundamental error occurs that is discovered in the process, then the Transmission Planner will have no choice but to promptly remove their request (i.e., as there is not sustainable evidence that the unit meets the "technically justified" criteria).** 5. The instruction in R4 to notify the TP, "within 180 calendar days of making changes thatalter the system response is too vague, despite the attempted clarification in footnote #3,since many activities can have some degree of impact as noted above. Reportablethresholds regarding degree of impact on system response and the expected duration areneeded. **Response: The SDT believes that we have achieved stakeholder consensus on the current**

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	language of the standard. The SDT believes specifying reportable thresholds for an infinite number of possible permutations is not practical for a standard. 6. Please add clarifying language to R5 to emphasize that this requirement is addressing unitsthat meet the NERC registry criteria but are smaller than the MVA size specified in theapplicability section. **Response: Thank you for pointing out the need to include further clarification. The SDT has clarified Section 4.2.4 in the Applicability Section as follows: "A technically justified unit that meets NERC registry criteria but is not otherwise included in the above Applicability sections 4.2.1, 4.2.2, or 4.2.3 and is requested by the Transmission Planner."** 7. Sub-requirement 2.1.4 is not clear - is this data the model block diagram and itsparameters? If so, simply state that. **Response: The phrase "model structure" refers to a block diagram without parameter values, thus the SDT feels like the language in R2.1.4 is clear. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.** 8. We recommend removing the first element of the logical AND statement of Attachment 1Row 4 (the same physical location element). If a GO has identical equipment at differentphysical locations, they are equivalent. A sister is a sister independent of the physicallocation. As long as the equipment is identical, the concept should be allowed to applyregardless of location. **Response: The SDT notes the general agreement among industry with using the proxy unit approach. The SDT respectfully maintains that the "same physical location" requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site walk down). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g., requirement for PSS in-service).** 9. The SDT should consider moving the capacity factor exemption information found inAttachment 1, row 7 into the applicability section. The applicability section should allow anentity to be able to determine if the standard applies to them and be able to determine thescope of the facilities

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	affected. It is best for those impacted to immediately know which unitsare in the scope and not have to realize the scope from a detailed study of the table ofAttachment 1. This would allow row 7 of Attachment 1 to be deleted. **Response: The SDT decided to place all the scenarios that effectively "exempt" otherwise applicable units in Attachment 1 for clarity. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
FirstEnergy	1. FE believes that Requirement 6 in an un-necessary requirement that the Transmission Planner must respond within 90 calendar days that the model is usable. The Transmission Planner should only respond if the information is not usable. We suggest that this requirement should be in a negative perspective and offer the following revision:R6. Each Transmission Planner shall notify the Generator Owner within 90 calendar days of receiving the verified excitation control system or plant volt/var control function model information in accordance with Requirement R2 that the model is not usable (see Sub-requirements 6.1 through 6.5), and shall include a technical description if the model is not usable that includes (but not limited to) the following: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning] 6.1. The excitation control system or plant volt/var control function model fails to initialize during a dynamic simulation along with suggested areas for investigation, 6.2. A listing of parameters that fail the Transmission Planner's data checks, 6.3. A no-disturbance simulation fails to result in non negligible transients ("flat line"), 6.4. For an otherwise stable simulation, a disturbance simulation results in the excitation control and plant volt/var control function model exhibiting an under-damped or critically damped response, or otherwise fails the Transmission Planner's stability criteria.6.5. The excitation control system or plant volt/var control function model submitted by the Generator Owner is either a user defined model or a model that is not acceptable for use in the Transmission Planner's Regional Reliability Organization footprint. **Response: The SDT believes that the level of specificity in R6 sub parts is adequate as drafted. Based on your and another commenters input, the SDT agreed that the sentence needed clarification. As such, the SDT decided to break the sentence up, with the first sentence ending at**

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	the next to last use of the word "usable" and we moved that last sentence to after the three criteria. The last sentence now reads: If the model is not usable, the Transmission Planner shall provide a technical description of why the model is not usable. Also, for ease of reading, the SDT moved the last sentence in the requirement to after the parts. 2. For clarity, Requirements 3 and 5 are confusing and seems to be the same. We feel the that R5 can be removed from MOD-026. This will also be consistent with the requirements of MOD-027. Response: The peer review type activities in R3 are for units which have been verified per the standard, or the verification process is on-going, but there are potential issues regarding that verification process. The associated Requirement R5 does allow the TP a means to pursue additional model information if the model's predicted response does not match the actual equipment response for units that are above the threshold in the current NERC Registry Criteria but below the standard's base Applicability MVA thresholds. The SDT believes this is a reasonable way to allow the TP to pursue model information in the rare instances where there is an issue with a model that is not part of the base applicability. Additionally, the SDT has clarified Section 4.2.4 in the Applicability Section as follows: "A technically justified unit that meets NERC registry criteria but is not otherwise included in the above Applicability sections 4.2.1, 4.2.2, or 4.2.3 and is requested by the Transmission Planner."
Response: The GVSDT thanks you for your comment. Please see responses above.	
Alberta Electric System Operator (AESO)	1. In section 4.2.2, The AESO considers the existing applicability for model validation to be more appropriate: o Connected to a transmission grid at 60 kV or higher voltage; and o single unit capacity of 10 MVA and larger; or o facilities with aggregate capacity of 20 MVA and larger. Response: As discussed in the Comment Form with the first posting of the draft MOD-026 standard, the SDT considered the extent of the facilities to be verified and how to reflect this in the "applicability" of this proposed standard. As a basis, the SDT recognized that the excitation system models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the Field Test, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the

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	exciter models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA and kV thresholds corresponding to 80% of connected MVA or greater for each Interconnection are proposed. The SDT believes that we have achieved stakeholder consensus on the current language of the standard. 2. Requirement R2, the AESO considers the existing validation period of 5 years to be more appropriate. **Response: The SDT believes that re-verification every 5 years is unnecessary. This position is supported by an overwhelming majority of comments received from the industry. As such, the SDT believes that we have achieved stakeholder consensus on the current language of the standard.** 3. Requirement R4, as written it appears owners of generating units that plan to change out the excitation control systems are not required to provided preliminary (design) data to the Transmission Planner only validated data. The AESO does not consider this to be appropriate as this preliminary (design) data should be provided to the Transmission Planner in advance of the change. **Response: This standard addresses model verification, not the submittal of preliminary design models. Model verification can occur only after the equipment is installed. The standard does not address development of the original model during the equipment commissioning process. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
ExxonMobil Research and Engineering	A stated purpose of Generator Verification is “to ensure that generator models accurately reflect the generator’s capabilities and operating characteristics.” Modeling behind-the-meter generation based on gross name-plate ratings will not accurately reflect those assets’ capabilities or operating characteristics, and, in fact, may seriously distort BES expansion plans or other modeling scenarios if name-plate ratings are used. Behind-the-meter generation is a misnomer. It is not comparable to utility or merchant generation in which the primary function is to deliver electric energy to the bulk

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	electric system. The primary function of behind-the-meter generation that employs cogeneration or combined heat and power (CHP) systems is to deliver thermal energy (usually in the form of steam) in support of the load's process technology. In the case of industrial loads, the capabilities or operating characteristics of that process are a function of the load's production schedule associated with its products (e.g., chemicals, petroleum, paper, etc.) and independent of conditions on the BES. Any electric power delivered to the BES is a residual by-product of the industrial process and generally a small fraction of the name-plate rating of the generator. Section III.c.4 of the Statement of Compliance Registry Criteria (v.5) and Exclusion E2 of the revised BES definition both recognize this fundamental characteristic of behind-the-meter generation and that is why neither document uses name-plate rating as a useful metric for behind-the-meter generation. The GVSDT is urged to do the same.
Response: The GVSDT thanks you for your comment. The GVSDT has used a subset of the registry criteria to identify applicable Facilities. If a unit meets the sub set of the registry criteria it is obligated to comply with the standard.	
Independent Electricity System Operator	a. No explicit NERC performance requirements for excitation system are a weakness. In Ontario, generating units are required to materially help regulate voltage as the Transmission Planner sets performance requirements for upper and lower ceilings, voltage response time, and stabilizer characteristics. This standard in its present form allows generators to continue to not materially help regulate voltage provided the documentation submitted to Transmission Planner is consistent with this lack of performance. **Response: The SAR for this draft standard calls for the verification of the generator's excitation system model data. Performance or operational requirements are beyond the scope of this standard.** b. In Ontario, experience has been that the models typically used by the Transmission Planner are not commonly employed by Generator Owners. The standard recognizes this in R1 by giving the obligation to the Transmission Planner to provide model block diagrams or data sheets to the Generator Owner. As the Transmission Planner may be unaware of practicable constraints on a unit and the Generator Owner may not be familiar with the reliability models; both parties must reach

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	an accommodation on the details to verify the model. R2 should be changed so the Generator Owner is required to provide a model that has been verified by a method accepted by the Transmission Planner. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The SDT believes that the method used to verify the model should be determined by those doing the model verification, and that the transmission planner should only be concerned with the result, which is a correct model for the equipment. The testing expert will determine the voltage excursion magnitude to use during testing and other details regarding how to do the test. Also the SDT consciously avoided specifying the quality of match between model and test a) to avoid risk of being over-prescriptive and too restrictive and b) because an industry accepted quantification of "match" does not exist. The focus is solely on "what" is required, not "how" it's done.** c. The measured performance of the OEL, UEL, stator current limiter or any other automatic control system that alters the behaviour of the excitation system should be part of the Generator Owner submission to the Transmission Planner as limiter performance can affect reliability decisions. No limiter that imposes more restrictive limits than the required short term field and armature current requirements in ANSI/IEEE 50.13 should be implemented without the Transmission Planner's approval. **Response: The SAR for this draft standard calls for the verification of the generator's excitation system model data. Performance or operational requirements are beyond the scope of this standard.** d. The concept of "applicable unit" should be extended to include static var generators and similar devices. All facilities with an excitation control system and more than 100 MVA of capability should fall under this standard. **Response: Static Var generators and other similar devices, such as Synchronous condensers, are not currently addressed in the NERC Registry Criteria. On an MVA capacity basis, the penetration of Synchronous condensers in North America is extremely low. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements**

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	would not make sense. Synchronous condensers do not generate real power as a source of revenue so Transmission Owners paying for synchronous condenser installation and maintenance do so for dynamic voltage support; most likely to extend a dynamic voltage security limit. As such, The Transmission Owner is highly motivated to understand and model synchronous condenser dynamic behavior. Based on this understanding the SDT has decided that with the current structure of the Compliance Registry Criteria, if there is a need to develop a Reliability Standard to model the expected behavior of dynamic voltage devices typically owned by Transmission entities, then a more appropriate strategy is to include Synchronous Condensers along with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) into a separate SAR. e. Changes to the generator (e.g. rewinds or active power output increases) will affect excitation system performance. The standard should require re-testing following other modifications that the Transmission Planner can show with simulations will require modifications to the excitation system to improve reliability. For example, turbine replacements often provide increased active power capability. At higher levels of active power, the excitation system can materially change without coordinated changes to over-excitation limiters. **Response: For the example given, increased active power would require an alteration in the Interconnection Agreement – and similar to a new unit, the transmission entity should be able to dictate terms which state activities that must be completed so that the increase in power can be reliably delivered to the transmission system – including any protection and/or limiter setting changes and any needed re-verification of models. The SDT believes that the vast majority of scenarios that could cause an alteration of excitation control system response changes that should drive a re-verification of models are captured in R4 and the corresponding footnote number 5. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.** f. R2.1 should be amended (see below) to add flexibility to include other practical combinations of units to be used for verification. For example, it can be more practicable to test wind and solar installation one feeder at a time but this is not allowable with the standard in its present form. Each applicable unit's model shall be verified by the Generator Owner using one or more models acceptable to the Transmission Planner. Verification of an individual unit rated less than 20 MVA

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	(gross nameplate rating) may be performed using either an individual unit, a combination of units, or plant aggregate model(s). **Response: The SDT thanks you for your comment. Based on your comment, the SDT has modified the applicable portion of Part 2.1 to read: "Verification for individual units rated less than 20 MVA (gross nameplate rating) in a generating plant (per Section 4.2.1.2, 4.2.2.2, or 4.2.3.2) may be performed using either individual unit or aggregate unit model(s) or both."** g. In Ontario we face resistance when our standards exceed NERC requirements. Would it be possible for the SDT in its response to offer its opinion on elements of our comments that are not incorporated into the next version of this standard? For example, if none of our comments can be adopted into the standard, we would appreciate responses such as: "In the opinion of the SDT, having more applicable units on closed loop voltage control, reducing the time to transmit verified information to the Transmission Planner, having specific excitation performance requirements, expanding verified information to include limiters and other devices that affect excitation system performance, and making the requirements in this standard applicable to wider range of equipment are all practices that will tend to improve reliability." Or "In the opinion of the SDT, the requirements in this standard are not intended to preclude continuing or implementing more stringent Transmission Planner requirements "This type of response would help us to continue to augment continent-wide standards with additional requirements to maintain reliability in our part of the interconnection. **Response: The SDT does believe that the requirements in this standard provide a floor and that individual regions or transmission entities, through venues such as interconnection agreements, can implement more stringent requirements. Unfortunately, the SDT scope is limited to drafting a national standard.** h. We appreciate the SDT's effort to implement our proposed language changes to remove a potential conflict with the Ontario regulatory practice respecting the effective date of implementing approved standards. The added language, unfortunately, was not added at the appropriate places. We suggest the SDT to move the wording " , or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities," in Section 5.1 to right after "approved by applicable regulatory approval", and move that same wording to right after "following applicable

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	regulatory approval" in Sections 5.2 to 5.4.Also, the same phrase should be appended to each of the four bullets in the Section "In those jurisdictions where regulatory approval is required:" of the Implementation Plan right after "following applicable regulatory approval." **Response: We have made the requested edits.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
South Feather Power Project	Applicability section 4.2.2.2 describes an Individual Generating Plant as consisting of multiple generating units that are directly connected at a common BES bus with a total capacity greater than 75 MVA. It would help if there was a proximity element to the definition of "Individual Generating Plant." My question/comment comes from the fact that I have three single unit powerhouses with a combined total capacity greater than 75 MVA connected to a single 115 kV radial line, with several miles of transmission line separating each unit from the other, but the radial line (which is owned by another entity) ultimately terminates at a single (common) point on a BES bus. Attached to this same radial transmission line are a distribution substation and another entity's small hydro plant, so it is not clear how this common point on a BES bus would be characterized.
Response: The GVSDT thanks you for your comment. The SDT believes that the current language is clear. Regarding your specific circumstance, if the three single unit powerhouses are interconnected to a common BES bus with an aggregate capacity greater than specified in the Applicability section for an individual generating plant, then that plant does meet the draft standard's threshold. If the three single unit powerhouses are not connected to a common bus, but are tapped at buses on various locations of the radial line, then their Applicability would be based on the individual unit thresholds in the Applicability section of the draft standard.	
Cowlitz PUD	Cowlitz supports the comments put together by the NAGF SRT:1. The standard is based on the assumption that it is possible to tune the acceptable modelscited in R1 such that their predictions will match actual voltage and reactive powerresponses to system Disturbances. The yet-to-be-defined acceptable models may not becapable of achieving this goal, however, because standard excitation component modelsare inadequate to predict with high fidelity the generation system

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	transmission system beyond the point of interconnection is not required. EPRI has developed software which supports non invasive ambient monitoring for model verification that is successfully being used by a number of entities. Other developers have also developed similar software. While it is true that many generators do not currently have necessary expertise, this expertise can be developed or hired. Proper software can be purchased to analyze the modeled response – utility grade dynamic simulation software used by Transmission Planners for regional and inter-regional studies does not have to be purchased. This standard has already undergone a NERC field test in the Summer of 2007 – one of the conclusions was that performing the activities specified in the draft standard will improve accuracy of the exciter model used in dynamic simulation. Entities from four regions participated, and all successfully completed the field test which validated that performing the activities specified in the draft standard will improve accuracy of the exciter model used in dynamic simulation. 2. There is presently no definition of the voltage excursion magnitude and intensity or therecording instrumentation sampling rate required for a valid verification event. There arealso no specifics regarding how closely the model must match the recorded response or forwhat period of time, just a requirement that it be deemed “usable” by the TP. The SDT isasking for a blank check, and we cannot agree to regulations for which it is impossible tosay at the time of balloting whether or not compliance can be achieved, let alone in afashion that is justified per the FERC order cited above.Perceived shortcomings in these respects would presumably trigger the TransmissionPlanner expression of concern described in R3, but it would be better to establish the rulesup-front rather than addressing the matter only after a GO has attempted to comply withMOD-026 and been found lacking. It was stated in a 7/29/11 webinar that a signal-to-noise ratio of at least 5:1 is needed for a meaningful validation, but this criterion did not make itinto the standard. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The SDT believes specifying a voltage excursion magnitude is prescriptive. The testing expert will determine the voltage excursion magnitude to use during testing. Also the SDT consciously avoided specifying the quality of match between model and test a) to avoid risk of being over-prescriptive and too restrictive and b) because an industry accepted quantification of “match” does not exist. The focus is solely on “what” is required, not “how” it’s**

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	done. 3. The term “rotational inertia” in R2.1.3 should be replaced with “inertia constant (H),” therotational inertia divided by MVA rating, since this is the parameter of interest for stabilitystudies. Either way, the obligation to conduct testing in this respect should be waived forunits having an OEM-developed value and no modifications to the rotating components,since rotational inertia can be identified more precisely via calculation than by clocking apost-trip over speed excursion. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard.** 4. The term “technically justified” in para. 4.2.4 on p.3 and in R5 is too vague, in that thedegree of actual-vs.-predicted mismatch triggering MOD-026-1 applicability is not specified.It is also not clear how this comparison is to be made if the Facility did not have to provide aMOD-026 model in the first place. In any event the wording of the R5 Violation SeverityLevels should be modified to start the clock only after agreement has been reached that arequest is technically justified. 6. **Response: The associated Requirement R5 does allow the TP a means to pursue additional model information if the model’s predicted response does not match the actual equipment response. Models do exist for these units through the processes defined in MOD-012 and 013, though they may not have been verified. The SDT believes this is a reasonable way to allow the TP to pursue model information in the rare instances where there is an issue with a model that is not part of the base applicability. Regarding the desire for criteria for mismatch, the standard states “what is required” but not “how to accomplish what is required.” The SDT considered ways to quantify a method for evaluating how well the equipment’s measured response matches the model’s predicted response for this and other requirements. However, a generally accepted technique or criteria for making this quantitative assessment does not exist. The SDT believes use of the term “match” is appropriate because the Webster’s dictionary defines “match” as something that is equal or similar to another.** **The SDT believes the existing wording of the VSL for R5 regarding when the clock starts is fair for all stakeholders and provides a well-defined and measurable initiation point. Also, the SDT**

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	believes that the activities described in R5 will rarely occur. One reason why this will rarely occur is because the only units that could be subjected to this requirement are those which are above the thresholds in the NERC Registry Criteria but are below the thresholds specified in the Applicability (Section 4). When they do occur, if the Transmission Planner obtains the recording of an event and subsequently perform a post mortem analysis and the results show that the response of the actual equipment does not match the predicted response of the model, the SDT believes that there will be no doubt that the unit fits the requirement of being declared "technically justified." If a fundamental error occurs that is discovered in the process, then the Transmission Planner will have no choice but to promptly remove their request (i.e., as there is not sustainable evidence that the unit meets the "technically justified" criteria). 5. The instruction in R4 to notify the TP, "within 180 calendar days of making changes thatalter the system response is too vague, despite the attempted clarification in footnote #3,since many activities can have some degree of impact as noted above. Reportable thresholds regarding degree of impact on system response and the expected duration are needed. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The SDT believes specifying reportable thresholds for an infinite number of possible permutations is not practical for a standard.** 6. Please add clarifying language to R5 to emphasize that this requirement is addressing units that meet the NERC registry criteria but are smaller than the MVA size specified in the applicability section. **Response: Thank you for pointing out the need to include further clarification. The SDT has clarified Section 4.2.4 in the Applicability Section as follows: "A technically justified unit that meets NERC registry criteria but is not otherwise included in the above Applicability sections 4.2.1, 4.2.2, or 4.2.3 and is requested by the Transmission Planner."** 7. Sub-requirement 2.1.4 is not clear - is this data the model block diagram and its parameters? If so, simply state that. **Response: The phrase "model structure" refers to a block diagram without parameter values, thus the SDT feels like the language in R2.1.4 is clear. The SDT believes that we have achieved**

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	stakeholder consensus on the current language of the standard.
Response: The GVSDT thanks you for your comments. Please see responses above.	
Exelon Corporation and its affiliates	Exelon again reiterates that the Standard should specifically define the acceptance criteria. The current draft (draft 4) of MOD-026-1 R.3 requires that a Generator Owner provide a written response to its Transmission Planner if the Transmission Planner deems the functional model is not “usable”, if there are technical concerns with the verification documentation, or if the model response did not match the recorded response to a transmission system event. This written response is to contain either the technical basis for maintaining the current model, the model changes, or a plan to perform model verification. It appears from previous comments of the GVSDT that the Generator Owner has final say on the model and the GVSDT has previously responded "that the standard is written so that the Generator Owner “owns’ the model, and as such, even with the peer review process described, the Generator Owner has final say on the voltage excursion used, including sampling rate, for model verification as well as determining if the equipment recorded response satisfactorily matches the model’s predicted response.” While Exelon agrees with this statement; Exelon again requests that this language be clearly articulated within the body of the Standard or that definitive acceptance criteria be added to the Standard.
Response: Thank you for your comment. The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The SDT believes specifying a voltage excursion magnitude is prescriptive. The testing expert will determine the voltage excursion magnitude to use during testing. Also the SDT consciously avoided specifying the quality of match between model and test a) to avoid risk of being over-prescriptive and too restrictive and b) because an industry accepted quantification of “match” does not exist. The focus is solely on “what” is required, not “how” it is done. Finally, the SDT has drafted the standard is such a manner that the Generator Owner is the “owner” of the model.	
American Transmission Company	For Requirement 6, ATC recommends the wording at the end of the requirement to read “that includes how any of the following criteria are not met:” because the existing wording does not express that the criteria are not met when the model is not usable.

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Response: Thank you for your comment. The SDT agreed that the sentence needed clarification. As such, the SDT decided to break the sentence up, with the first sentence ending at the next to last use of the word "usable." The second sentence now reads: The TP will provide a technical description of why the model is not usable.	
CenterPoint Energy	In R6, CenterPoint Energy recommends changing 90 days to 180 days for a Transmission Planner to notify the Generator Owner that a model is usable or is not usable. Such a change will allow time for model verification through the various regional processes for generator data submittals and dynamic planning case building.
Response: Thank you for your comment. The SDT believes that 90 days is sufficient time for the Transmission Planner to notify the Generator Owner, and that we have achieved stakeholder consensus on the current language and timing specification contained in the standard.	
Ingleside Cogeneration LP (Voting entity Occidental Chemical Corporation)	Ingleside Cogeneration LP agrees that the ability for Transmission Planners to effectively model and simulate actual system response to voltage transients can lead to reliability improvements. In addition, the technical veracity and implementation time frames in the latest version of MOD-026-1 are far improved over previous versions. However, we are concerned with the aggregate work load that all five standards in Project 2007-09 will place upon our engineering and operations organizations. Each has its own unique purpose, which means unique processes to support them - as well as test results that demonstrate compliance. With so much uncertainty surrounding this program, we cannot agree to proceed without the following items being addressed:1) All requirements for recurring tests (R2) must contain language that focuses on the strength of the validation process - not the execution. This could be similar to that used in the CIP version 5 standards calling for the Responsible Entity to implement an action "in a manner that identifies, assesses, and corrects deficiencies". Experience has shown that without this preface, auditors will focus on missed due dates, whether or not all check boxes are filled in, and statements showing that every sub-requirement was addressed - even those not applicable to the facility. The CEA's focus needs to be on the entity's commitment to the validation effort, not the documentation.2) The Compliance organization needs to be engaged in the development process so that industry

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	stakeholders have a sense of how adherence to the standard will be determined. The existing process is disconnected - leading to inconsistent interpretations of the drafting team's original intent. Other projects have begun to post drafts of the RSAWs concurrently with the standards for exactly this reason. The SDT should take note that these modifications are consistent with the risk-based compliance direction that both NERC and FERC support. The intent is to focus industry and regulatory resources on the reliability aspects of the initiative - not its administrative aspects.
Response: The GVSDT thanks you for your comments. Your issues relate to the "Find, Fix and Track" process that was most notably incorporated in the CIP body of standards. For example, CIP-003-5, Requirement R2 states: "Each Responsible Entity for its assets identified in CIP-002-5, Requirement R1, Part R1.3, shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented cyber security policies that collectively address the following topics, and review and obtain CIP Senior Manager approval for those policies at least once every 15 calendar months." This requirement relates to a specific program that addresses a wide range of topics, including documentation of the processes involved. The requirements of MOD-026 are to simply verify the model and provide that model to the Transmission Planner. Under this standard, the responsible entity either performed the verification and reported it or they didn't. There is no inherent program deficiency that can be identified and corrected. The GVSDT does not believe that this approach is applicable to the requirements that we have developed.	
Oncor Electric Delivery Company	Oncor does not support the position that the TP is applicable for this standard. In the ERCOT Interconnection, Section 3 and Section 5 of the ERCOT Nodal Operating Guides prescribes the ERCOT ISO to request and receive generation unit performance data, not the TP. Oncor takes the position that a regional variance be granted for the ERCOT Interconnection such that the standard would prescribe that the PA only be the only requestor and receiver of unit performance data to support Section 3 and Section 5 of the ERCOT Nodal Operating Guides.
Response: Thank you for your comment. Regarding the responsibilities assigned to the Transmission Planner in the draft standard, the SDT believes standard language lines up well with the vast majority of entity business practices in effect regarding the interactions between generation and transmission entities when collaborating on generator dynamic models. There are defined NERC processes outside the GV SDT effort where entities can request a regional variance. Alternatively, the Transmission	

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Planner could delegate the responsibility to another such as its Planning Authority	
Southern Company	Please add clarifying language to R5 to emphasize that this requirement is addressing units that meet the NERC registry criteria but are smaller than the MVA size specified in the applicability section. **Response: Thank you for pointing out the need to include further clarification. The SDT has clarified Section 4.2.4 in the Applicability Section as follows: "A technically justified unit that meets NERC registry criteria but is not otherwise included in the above Applicability sections 4.2.1, 4.2.2, or 4.2.3 and is requested by the Transmission Planner."** Sub-requirement 2.1.4 Is not clear - is this data the model block diagram and its parameters? If so, simply state that.SCS agrees with the modifications to the Periodicity Table as they both simplify and clarify the periodicity. **Response: The phrase "model structure" refers to a block diagram without parameter values, thus the SDT feels like the language in R2.1.4 is clear. The SDT believes that we have achieved stakeholder consensus on the current language of the standard. Thank you for your positive comment regarding the modifications to the Periodicity Table.**
Response: Thank you for your comment. Please see responses above.	
Florida Municipal Power Agency	Related to our comment on MOD-025, if synchronous condensers are only owned by TOs, then the excitation system of a synchronous condenser would not be verified in MOD-026 because it is only applicable to GOs. FMPA recommends that synchronous condenser excitation systems should be verified through the same process, and as a result, if a synchronous condenser is owned by a TO, then a TO should have applicability to it only for excitation systems on synchronous condensers it may own.
Response: The GVSDT thanks you for your comment. Synchronous condensers are not currently addressed in the NERC Registry Criteria. On an MVA capacity basis, the penetration of Synchronous condensers in North America is extremely low. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. The MOD-025 standard addresses steady state modeling but does not contain peer review requirements so the GVSDT	

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believes incorporating synchronous condensers into the MOD-025 standard is a better fit. Synchronous condensers do not generate real power as a source of revenue so Transmission Owners paying for synchronous condenser installation and maintenance do so for dynamic voltage support; most likely to extend a dynamic voltage security limit. As such, The Transmission Owner is highly motivated to understand and model synchronous condenser dynamic behavior. Based on this understanding the SDT has decided that with the current structure of the Compliance Registry Criteria, if there is a need to develop a Reliability Standard to model the expected behavior of dynamic voltage devices typically owned by Transmission entities, then a more appropriate strategy is to include Synchronous Condensers along with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) into a separate SAR.	
Manitoba Hydro	Section 2.1.2 - Manitoba Hydro suggests revising the text to read as follows: Manufacturer, model number (if available), and type of excitation control system and the plant volt/var control function (if installed). **Response: Based on your comment, the SDT realized that the sentence could be refined and as such refined the sentence in sub part 2.1.2 read: "Manufacturer, model number (if available), and type of the excitation control system including, but not limited to static, AC brushless, DC rotating, and/or the plant volt/var control function (if installed)."** R2.1.4. - Manitoba Hydro proposes that only the text of "Model structure and data for the excitation control system" is kept. An excitation control system consists of generator and excitation system as per IEEE 421.1 and 421.5. 4.2 – **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. Note that the SDT did add the term "impedance compensation" to Footnote 1 in the description of what constitutes a excitation control system for synchronous machines – the SDT believes that calling out "impedance compensation' is important as determined in its role in previous events.** The language immediately preceding the bullets is unclear (i.e. 'that meet the following' should possibly be reworded as 'provided they meet the following'). **Response: The SDT has modified the applicable portion of Part 2.1 to read: "Verification for individual units rated less than 20 MVA (gross nameplate rating) in a generating plant (per Section**

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	4.2.1.2, 4.2.2.2, or 4.2.3.2) may be performed using either individual unit or aggregate unit model(s) or both." R1 -This requirement would be clearer if rewritten as 'Within 90 calendar days of receiving a written request, each Transmission Owner shall provide to its requesting Generator Owner: **Response: The SDT did modify R1 so that it now reads: Each Transmission Planner shall provide the following requested information to the Generator Owner within 90 calendar days of receiving a written request:** 'General Comment - Manitoba Hydro has a concern with respect to the phased in implementation measured by percent compliance. We believe that this may lead to a potential for some uncertainty and debate. Does a phased in implementation such as this, do anything to increase reliability? **Response: The percentages in the Effective Date section refer to the entity's applicable unit gross MVA for each Interconnection. The SDT believes that the calculation of the percentages will be trivial, and will allow Generator Owners flexibility as compared to a "number " or "percentage" of units approach.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
Northeast Power Coordinating Council	Suggest the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the Standard and the associated Implementation Plans. Given recent experience with other Standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings. **Response: The percentages in the Effective Date section refer to the entity's applicable unit gross MVA for each Interconnection. The SDT believes this is a clear designation that the thresholds are determined by the percent of unit gross MVA and not by the number of devices. This does mean that the total applicable unit MVA per Interconnection, as specified in Section 4.2 (Applicability / Facilities) will have to be determined by the Generator Owner. The SDT believes that we have**

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	achieved stakeholder consensus on the current language of the standard.
Response: The GVSDT thanks you for your comment.	
American Electric Power	The SDT should consider either removing MOD-026-1 R5 or merge R3 and R5 because a) MOD-026-1 R3 and R5 appear to have the same objective with similar wording and b) MOD-027-1 does not have the equivalent of MOD-026-1 R5.MOD-026-1 R6 ends with "...that includes the following:" yet whatever the SDT intended to follow is missing. Please note that subparts 1 through 3 are referenced in parenthetical statements within the respective requirements and that it does not make sense that these subpart criteria are also what needs to follow "...that includes the following:"
Response: The GVSDT thanks you for your comment. The peer review type activities in R3 are for units which have been verified per the standard, or the verification process is on-going, but there are potential issues regarding the model. The associated Requirement R5 does allow the TP a means to pursue model information from additional units if the model's predicted response does not match the actual equipment response for units that are above the threshold in the current NERC Registry Criteria but below the standard's base Applicability MVA thresholds. The SDT believes this is a reasonable way to allow the TP to pursue model information in the rare instances where there is an issue with a model that is not part of the base applicability. Additionally, the SDT has clarified Section 4.2.4 in the Applicability Section as follows: "A technically justified unit that meets NERC registry criteria but is not otherwise included in the above Applicability sections 4.2.1, 4.2.2, or 4.2.3 and is requested by the Transmission Planner." A requirement equivalent to MOD-026 R5 is not being proposed for MOD-027-1. It is extremely unlikely that the turbine/governor and load control or active power/frequency control system will contribute to a stability limit. Also, governor response is not consistent from one frequency excursion event to the next. Therefore, the SDT did not feel that such a Requirement in MOD-027-1 was necessary. Regarding the comment for Requirement 6, the SDT agreed that the sentence needed clarification. As such, the SDT decided to break the sentence up, with the first sentence ending at the next to last use of the word "usable." The second sentence now reads: The TP will provide a technical description of why the model is not usable. The SDT believes this will clarify the confusion that you pointed out.	
PPL Corporation NERC Registered Affiliates	The standard is based on the assumption that it is possible to tune the acceptable models cited in R1 such that their predictions will match actual voltage and reactive power responses to system

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	Disturbances. The yet-to-be-defined acceptable models may not be capable of achieving this goal, however, because standard excitation component models are inadequate to predict with high fidelity the generation system response that is the subject of MOD-026-1. Such models do not take into account, for example, equipment thermal capability limitations and the capping of reactive power output to respect aux bus voltage limits. The SDT is therefore asking for a considerable advancement in the excitation modeling state of the art, to be undertaken in parallel by the owners of every generation unit in North America. This is a doubly daunting task in that GOs often do not have any dynamic modeling software or expertise, much less the ability to invent something new, because the present approach to the subject is that GOs just provide the values of input parameters to the TP, which owns and runs models. Independent GOs (i.e. entities that are not part of a vertically-integrated utility) moreover do not have and cannot obtain information on the system outside the plant battery limits. This circumstance renders them unable to model the plant-T&D interactions associated with Disturbances, and independent GOs may therefore forever remain unable to develop model results that closely match actual Disturbance responses. The approach being taken in MOD-026-1 is consequently viewed as being technically infeasible for the present state of the art as well as unjustified in light of FERC's March 15, 2012 FFT Order to propose specific standards or requirements that should be revised or removed [or not enacted in the first place] due to having little effect on reliability or because of compliance burdens. The SDT should instead collaborate with industry associations (EPRI, IEEE, NAGF), equipment OEMs, and modeling services vendors to develop the right tools for the job, and put the new models through trial runs at several plants. These trials should be limited to data-collection means that can be non-invasively employed (e.g. online voltage step-response tests, low-load rejection during normal stop events), and should lead to definition of specific testing means for definition of specific model parameters. The SDT should then put out for voting a standard requiring TOPs to own and run these models, and requiring GOs to provide them the appropriate input data, developed via the non-invasive means stated above. **Response: Excitation control system model is well established and documented. Some of those documents are referenced in Section G of the standard, including IEEE 421.2 Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems. The acceptable models referenced in Requirement 1 will predominately consist of standard library**

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	models included in software manufacturer dynamic simulation packages and are well known and understood – many are models developed by IEEE. Information on the transmission system beyond the point of interconnection is not required. EPRI has developed software which supports non invasive ambient monitoring for model verification that is successfully being used by a number of entities. Other developers have also developed similar software. While it is true that many generators do not currently have necessary expertise, this expertise can be developed or hired. Proper software can be purchased to analyze the modeled response – utility grade dynamic simulation software used by Transmission Planners for regional and inter-regional studies does not have to be purchased. This standard has already undergone a NERC field test in the Summer of 2007 – one of the conclusions was that performing the activities specified in the draft standard will improve accuracy of the exciter model used in dynamic simulation. Entities from four regions participated, and all successfully completed the field test which validated that performing the activities specified in the draft standard will improve accuracy of the exciter model used in dynamic simulation. There is presently no definition of the voltage excursion magnitude and intensity or the recording instrumentation sampling rate required for a valid verification event. There are also no specifics regarding how closely the model must match the recorded response or for what period of time, just a requirement that it be deemed "usable" by the TP. Perceived shortcomings in these respects would presumably trigger the Transmission Planner expression of concern described in R3, but it would be better to establish the rules up-front rather than addressing the matter only after a GO has attempted to comply with MOD-026 and been found lacking. It was stated in a 7/29/11 webinar that a signal-to-noise ratio of at least 5:1 is needed for a meaningful validation, but this criterion did not make it into the standard. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The SDT believes specifying a voltage excursion magnitude is prescriptive. The testing expert will determine the voltage excursion magnitude to use during testing. Also the SDT consciously avoided specifying the quality of match between model and test a) to avoid risk of being over-prescriptive and too restrictive and b) because an industry accepted quantification of "match" does not exist. The focus is solely on "what" is required, not "how" it's**

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	done. The term "rotational inertia" in R2.1.3 should be replaced with "inertia constant (H)," the rotational inertia divided by MVA rating, since this is the parameter of interest for stability studies. Either way, the obligation to conduct testing in this respect should be waived for units having an OEM-developed value and no modifications to the rotating components, since rotational inertia can be identified more precisely via calculation than by clocking a post-trip overspeed excursion. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard.** The instruction in R4 to notify the TP, "within 180 calendar days of making changes that alter the system response is too vague, despite the attempted clarification in footnote #3, since many activities can have some degree of impact as noted above. Reportable thresholds regarding degree of impact on system response and the expected duration are needed. **The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The SDT believes specifying reportable thresholds for an infinite number of possible permutations is not practical for a standard.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
Southwest Power Pool Reliability Standards Development Team	There is a problem with the threshold in the standard of 100MVA units. We would suggest that this be in line with the BES DEF and reduce this threshold to 20MVA. Why has the threshold been increased? If the data has to be provided for LGIA under the Tariff then we should be verifying the data. There is also inconsistency between the standards posted for comment I.E. PRC-019-1. We would like to see better consistency for the thresholds between all the standards under this project and with the other projects associated with generator thresholds.
Response: The GVSDT thanks you for your comment. The individual unit and aggregate plant ratings used in the applicability section were carefully derived for each Interconnection to capture validation of approximately 80% of the total installed base in that region. The selection of these applicability requirements intend to strike the most reasonable balance between managing the	

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costs to perform tests and validation vs. ultimately assuring that the reliability of the Bulk System is not compromised due to poor models. It is recognized that boundaries within an interconnection can be drawn that can result in more or less than 80% of the connected MVA. However, R5 allows the TP to request the GO to perform a model review, if the unit is not included in the base Applicability but if that unit which is equal to or greater than the thresholds in the NERC Registry Criteria. **Regarding your comment asking for better consistency for the thresholds between all the standards under the GV SDT effort, each individual standard was developed based on the reliability needs and benefits that each specific standard requires. There are fundamental differences in the types of verifications required under each standard. Therefore, the reliability needs for each standard will not necessarily be the same, nor will the applicable facilities necessarily be the same.**	
Duke Energy	Typo - In the Effective Date section 5.3, strike the word "thirty" after the word "quarter" in the fourth line in the clean version.
Response: The GVSDT thanks you for your comment. The extra "thirty" has been removed in the current draft of the standard.	
Utility Services	Utility Services suggests the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the standard and the associated Implementation Plans. Given our recent experience in other standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases, percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings.
Response: The GVSDT thanks you for your comment. The percentages in the Effective Date section refer to the entity's applicable unit gross MVA for each Interconnection. The SDT believes this is a clear designation that the thresholds are determined by the percent of unit gross MVA and not by the number of units. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.	
NIPSCO	Verification requirements would be burdensome, e.g., model response by staged testing or

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	comparison with a system disturbance may be of only limited value. Another basic problem with this standard is the unnecessary back and forth between generation owners and transmission planners in the data development and collection. This standard could be greatly simplified for all involved parties with reporting requirements similar to MOD-025 where the generation owner provides information to the transmission planner upon the installation of new equipment or the modification of existing equipment. Given the above, Transmission Planning recommends a vote against this standard in its present form.
Response: The GVSDT thanks you for your comment. The SDT believes peer review is an essential part of the model verification process irrespective of criteria or guidelines available from industry since peer review provides the Transmission Planner an opportunity to review the data and identify problems or errors with information provided. This peer review process is not necessary for the validation of unit steady state parameters, but is necessary for dynamic model verification to ensure accurate models that are compatible with dynamic simulation programs. Also, the SDT believes that the recording of the unit's response to a staged open or closed step in voltage test and/or an ambient voltage event is of great value and can be used to verify the model. Note that utilizing ambient monitoring inherently removes the need for any staged testing.	
ReliabilityFirst	VSL Requirement R6 - ReliabilityFirst still believes the VSL for Requirement R6 is not meeting the intent of FERC VSL Guideline #3 "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement." Requirement R6 clearly requires the Transmission Planners to "...notify the Generator Owner... ", while the corresponding VSL states "The Transmission Planner provided a written response to the Generator Owner indicating..." The VSL is adding additional requirements on the TP (i.e. provide written response) which are not required within the actual requirement (nowhere in R6 is the TP required to provide a written response). If it is the intent of the SDT to have the TP provide a written response, ReliabilityFirst recommends adding that language to the requirement.
Response: The GVSDT thanks you for your comment. The GVSDT has made the requested edit in R6 indicating that the response by the Transmission Planner to the Generator Owner is required to be a written response.	

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PSEG	We voted “Negative” on this standard the reasons shown below.This FIRST COMMENT was provided for MOD-025-1, MOD-026-1, MOD-027-1, and PRC-019-1.1.SYNCHRONOUS CONDENSERS: The GVSDT is not working as a “team” with regards to synchronous condensers owned by TOs. The team working on this standard and PRC-019-1 INSIST that they be included as “applicable facilities,” while the team working on MOD-026-1 has stated otherwise. We provided this comment to the MOD-026-1 team in the last set of comments:”The exclusion of synchronous condensers (and other reactive devices) in MOD-026-1 per the rationale provided in the Background (with which we agree) states “Synchronous condensers are not currently addressed in the NERC Registry Criteria” However, companion standards under Project 2007-09 (MOD-025-2 and PRC-019-1) are applicable to synchronous condensers. The GVSDT should address this inconsistency.”The SDT responded as follows:”The SDT believes that MOD-026 is different from the other standards with respect to synchronous condensers due to the complex interaction required between the Transmission Planner and the Generator Owner, and thus believes it better to wait for efforts by others to define where synchronous condensers fit in the functional model.”In response to a similar comment on MOD-025-2 and PRC-019-1, we received these responses:MOD-025-1: “The GVSDT thanks you for your comment. There was overwhelming industry support (approximately 96%) for inclusion of synchronous condensers at the first posting of MOD-025-2. The Definition of Bulk Electric System (BOT Adoption Jan 2012) includes in “I5 - Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I2.”PRC-019-1: “The SDT feels that it is appropriate to include synchronous condensers because of their similarity to generators in terms of dynamic reactive power supply, voltage control, disturbance response, control functions, and protection systems. For this reason the SDT proposes to apply to the standard to similar size generators and synchronous condensers.”We need to see “one” statement from the SDT on the inclusion or exclusion of synchronous condensers that makes sense technically, and soon.This **Response: The GVSDT is indeed working as a “team” with these standards. Each individual standard was developed based on the reliability needs and benefits that each specific standard requires. There are fundamental differences in the types of verifications required under each standard. Therefore, the reliability needs for each standard will not necessarily be the same, nor**

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	will the applicable facilities necessarily be the same. Given the response by industry in a prior posting, the GVSDT concludes that stakeholder consensus has been achieved with respect to not including synchronous condensers in the current draft of MOD-026, given the qualifications that follow: **Synchronous condensers are not currently addressed in the NERC Registry Criteria. On an MVA capacity basis, the penetration of Synchronous condensers in North America is extremely low. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. The MOD-025 standard addresses steady state modeling but does not contain peer review requirements so the GVSDT believes incorporating synchronous condensers into the MOD-025 standard is a better fit. Synchronous condensers do not generate real power as a source of revenue so Transmission Owners paying for synchronous condenser installation and maintenance do so for dynamic voltage support; most likely to extend a dynamic voltage security limit. As such, The Transmission Owner is highly motivated to understand and model synchronous condenser dynamic behavior. Based on this understanding the SDT has decided that with the current structure of the Compliance Registry Criteria, if there is a need to develop a Reliability Standard to model the expected behavior of dynamic voltage devices typically owned by Transmission entities, then a more appropriate strategy is to include Synchronous Condensers along with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) into a separate SAR.** SECOND COMMENT was provided for MOD-025-1, MOD-026-1, MOD-027-1, and PRC-024-1.2.DATA SHARING POLICY: For all of the MOD standards in this, only Transmission Planners are the recipient of the data developed. We asked that the standard require that the TP be required to share the data with others. The response we received is that the Functional Model requires the TP to share data with the TOP. Unfortunately, the Functional Model is unenforceable. We note that in PRC-024-1, R6 requires the GO to share its data with the RC, PC, TOP, and TO, upon request. Unless the same data is shared across all “modelers,” the result will be outdated data in someone’s model, which can have a bad result. The team should have one broad “data sharing” policy in the three MOD standards and PRC-024-1. Since the TP receives data in three of the standards, we suggest this language or similar language: The GO shall provide data to its TP within 60 days of its development [describe the data]. The TP shall provide the same data to any RC, PC, TP, or TOP within 60 days of

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	receiving a request for **Response: The GVSDT has written the requirements of this body of standards based on the NERC Reliability Functional Model. The requirements of Reliability Standards MOD-010-0. MOD-011-0, MOD-012-0 and MOD-013-1 address the requirement for steady state and dynamic models (which are planning models) and the dissemination of these models to appropriate entities. The data to build Real-time models that are necessary for reliability and used by Reliability Coordinators and Transmission Operators are addressed in standards IRO-010-1a and TOP-003-2 respectively. The GVSDT does not see any reason to include duplicative requirements in this standard.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
ISO-New England	Requirement R1 may bring out some concern over the copyrighted models supplied by the simulation software vendors. Hopefully this can be worked out with the vendors. **Response: The software manufacturers have indicated that they will make accommodations so that generator owners without software licenses can receive the block diagrams and data sheets.** Requirement R2.1.3 should indicate the requirement for the total combined *turbine*/generator inertia constant. Simulations need to study the combined inertia of the turbine and generator not just the generator. **Response: The SDT believes that the term used in the draft standard, total rotational inertia, clearly conveys that it is the entire inertia that is connected to the shaft driving both the turbine and the generator and any other mass.** A requirement R2.1.7 should be added to require verification of generator excitation limiter settings. **Response: The SDT believes that the specificity in Part 2.1.3 includes any model data that is relevant to the verification of the excitation control system.** A requirement R2.1.8 should be added to require verification of supplementary voltage control inputs. **Response: The SDT believes that the specificity in Part 2.1.3 includes any model data that is**

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	relevant to the verification of the excitation control system Requirement R3 only requires a “written response” from a Generator Owner to the Transmission Planners notification that a model is not useable. Wording must be included so that ultimately the Generator Owner shall provide a “usable model” to the Transmission Planner. **Response: Requirement R3 is a “peer review” type requirement to ensure cooperation between the Generator Owner and the Transmission Planner. The SDT believes peer review is an essential part of the model verification process since the peer review provides the Transmission Planner an opportunity to request the Generator Owner to review the data and assist in identifying problems or errors with information provided. The SDT believes that all entities will be equally motivated to resolve model issues. This process was over whelming supported by Industry based on their responses in prior postings.** Requirement R4 must be modified so that models are provided prior to making changes in the excitation control system or plant volt/var control function. It is counter to system reliability to allow generators to modify and subsequently operate equipment without notifying the Transmission Planner. **Response: This standard addresses model verification, not the submittal of preliminary design models. Model verification can occur only after the equipment changes are implemented. The standard does not address development of the original model during the equipment commissioning process. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.** Footnote 6 should be modified to include ability for the Transmission Planner to require a verified model from a generator under the size threshold if the generator impacts the BES. **Response: Regarding provision of a reason the unit impacts the BES, R5 and Footnote 6 have undergone several modifications around this point. The SDT believes the existing R5 and Footnote 6 language strikes the best compromise to equitably satisfy all stakeholders as it allows Transmission Planners a way to request revised model data or a model verification for models that meet or exceed the NERC registry criteria thresholds but is below the standard’s base applicability.**

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	Requirement R6 sub-requirement wording should be changed to indicate the Transmission Planner shall notify the Generator Owner if the excitation model *does not* initialize, a no-disturbance simulation results in transients or a disturbance simulation results in a model exhibiting negative damping. **Response: The SDT has modified the language in R6 and we believe that the new language will address your concerns.**
Response: The GVSDT thanks you for your comment. Please see responses above.	

END OF REPORT