NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project 2007-09 Generator Verification
MOD-027-1

The Project 2007-09 Generator Verification Standard Drafting Team (GVSDT) thanks all commenters who submitted comments on the proposed revisions to MOD-027-1. 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 46 sets of comments, including comments from approximately 152 different people from approximately 98 companies representing 9 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 vast majority of commenters agreed with the revisions to Attachment 1 clarifying that for units that do not respond to frequency excursions, Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner, and that units which respond to over-frequency would need to have verification performed. No modifications were made to the draft standard as a result of industry comments for Question 1.

The vast majority of industry agreed that the revised Attachment 1 is clearer. There were a few minority comments about some of the specific rows in the Attachment, including proposals to refine the proxy sister unit philosophy and to move capacity factor philosophy back to the Applicability Section. However, the vast majority of industry agreed with the modified Attachment 1 and no further revisions were made to Attachment 1.

Based on stakeholder comments, the GVSDT made the following clarifications to the standard:

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

- 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." Also, in 5.1, the GV SDT changed the beginning of the first sentence from: "For Requirements R1, and R3 through R6 …" to "For Requirements R1, and R3 through R5 …" to reflect that there are five, not six requirements in the standard.

- 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 Date Section, "… in those jurisdictions where regulatory approval is required …" of the Implementation Plan right after, "… following applicable regulatory approval." This was done to address regulatory approvals in Canada.

- In the Applicability section 4.2.3, added the word "in" so that the phrase now reads, "Generation in the ERCOT Interconnection…" to be consistent with the language associated with the other interconnections (sections 4.2.1 and 4.2.2).

- 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 …"

- 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." Stakeholders believed that this added clarity to the Requirement.

- In the previous posting, there was a problem with footnote 4 where the language, "Error! Bookmark not defined," was included in the language of the Requirement R4. This has been corrected.

- Several commenters provided suggestions for improvements to Requirement R5. The GVSDT 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. Also, for ease of reading, the GVSDT moved the last sentence in the requirement to after the Requirement Parts 1-3.

Index to Questions, Comments, and Responses

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

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

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
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	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	Registered Ballot Body Segment									
				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					
46.	Individual	John Martinsen	Snohomish County PUD No.1	X		X	X	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 Company Services, Inc. - Gen
Snohomish County PUD No.1	Snohomish County PUD No.1 (SNPD) supports New York Power Authority (NYPA) comments.
Liberty Electric Power LLC	NAGF
Brazos Electric Power Cooperative, Inc.	ACES Power Marketing
Nebraska Public Power District	MRO NSRF

1. **The GVSDT has revised Attachment 1 to attempt to clarify that, for units that do not respond to frequency excursions, Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed. Do you agree with this revision? If not, please explain in the comment area below.**

Summary Consideration: The vast majority of commenters agreed with the revisions to Attachment 1 clarifying that for units that do not respond to frequency excursions, Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner, and that units which respond to over-frequency would need to have verification performed. No modifications were made to the draft standard as a result of industry comments for Question 1.

Organization	Yes or No	Question 1 Comment
Independent Electricity System Operator	No	Attachment 1 Row 7 leaves the impression responding to frequency excursion is merely a choice and this impression is harmful to reliability. Few "applicable units" should be unresponsive to over and under frequency excursions. If Generator Owners can choose to not help regulate frequency by simply notifying the Transmission Planner, why would any Generator Owner continue to regulate frequency? The attachment should be changed so units are unresponsive to frequency excursions only under conditions accepted by the Transmission Planner.
Response: The GVSDT thanks you for your comment. The SAR for this draft standard calls for the verification of the generator's Turbine/Governor and Load Control or Active Power/Frequency Control Function model data. Performance or operational requirements are beyond the scope of this standard. It is important that the correct response be modeled so that the simulation represents reality. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.		
Cowlitz PUD	No	Cowlitz supports the comments of the NAGF SRT:1. The SDT should consider moving the capacity factor exemption information found

Organization	Yes or No	Question 1 Comment
		inAttachment 1, row 8 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 8 of Attachment 1 to be deleted.
Response: The GVSDT thanks you for your comment. 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.		
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: The GVSDT thanks 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 both the functional model and 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.		

Organization	Yes or No	Question 1 Comment
Ameren	No	We believe that there is a discrepancy between the language in the requirement and VSL for R4 and Row 4 of the Attachment 1. In the requirement, a 180 day period is stated, while in Row 4 of Attachment 1, a 365 day period is stated.
Response: The GVSDT thanks you for your comment. 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 verification plan is submitted to the Transmission Planner, then in accordance with Requirement 2, Row 6 of Attachment 1 would specify that the Generator Owner has an additional 365 days to actually perform the verification – including transmitting the verified model, documentation, and data to the Transmission Planner.		
PPL Corporation NERC Registered Affiliates	No	Why wouldn't the GVSDT just identify (i.e. show reference note on Attachment 1 table) that "Applicable units does not include units that don't respond to frequency excursions (e.g., base-loaded units)"?
Response: The GVSDT thanks you for your comment. 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.		
ExxonMobil Research and Engineering	No	No comments on the question.
Idaho Power Company	Yes	Idaho Power System Planning agrees with the revisions made to Attachment 1.
Response: The GVSDT thanks you for your comment.		
Manitoba Hydro	Yes	None.
Southwest Power Pool Reliability	Yes	

Organization	Yes or No	Question 1 Comment
Standards Development Team		
Tennessee Valley Authority	Yes	
pacificorp	Yes	
Bonneville Power Administration	Yes	
Southern Company	Yes	
FirstEnergy	Yes	
Dominion	Yes	
Duke Energy	Yes	
Luminant	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Dynegy	Yes	
TransAlta Centralia Generation LLC	Yes	
PSEG	Yes	
Xcel Energy	Yes	
Ingleside Cogeneration LP (Voting entity Occidental Chemical Corporation)	Yes	

Organization	Yes or No	Question 1 Comment
American Transmission Company	Yes	
Wisconsin Electric Power Company	Yes	
American Electric Power	Yes	
Northeast Utilities	Yes	
South Carolina Electric and Gas	Yes	
Chelan PUD	Yes	
Exelon Corporation and its affiliates	Yes	
Georgia Transmission Corp.	Yes	
ISO-New England	Yes	

2. The GVSDT has revised Attachment 1 to make the periodicity requirements more clear. Do you agree with these revisions? If not, please explain in the comment area below.

Summary Consideration: The vast majority of industry agreed that the revised Attachment 1 is clearer. There were a few minority comments about some of the specific rows in the Attachment, including proposals to refine the proxy sister unit philosophy and to move capacity factor philosophy back to the Applicability Section. However, the vast majority of industry agreed with the modified Attachment 1.

Organization	Yes or No	Question 2 Comment
ACES Power Marketing Standards Collaborators	No	(1) While the clarity of Attachment 1 has been improved, we noticed a couple of issues. Note 3 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 2 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 3. 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 used to verify the model and the subsequent verification and the transmittal of the**

Organization	Yes or No	Question 2 Comment
		verified model, documentation, and data to the Transmission Planner. (2) Row 4 in Attachment 1 states that it applies to initial verification for a newly applicable unit or for an existing applicable unit with a new turbine/governor and load control or active power/frequency control equipment control system. However, Requirement R4 also applies to changes to the same control system. Wouldn't complete replacement be a change? We recommend modifying Attachment 1 to avoid this overlap. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The SDT feels like the distinction of a complete replacement of an governor 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.** (3) Per Requirement R4 and Row 6 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 4 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 turbine / governor 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 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.**

Organization	Yes or No	Question 2 Comment
		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 comment. Please see responses above.		
Tennessee Valley Authority	No	Attachment 1, Row Number 5, 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 comment. 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 governor droop response vs. constant load set point) or equipment with identical design ratings, but different control system settings which would result in different models and performance).		
Consumers Energy	No	Consumers' previous comments - The generator model with the excitation system and the load rejection testing or frequency step response testing is difficult to perform and has possibilities of damaging equipment and causing reliability issues on the system in order to perform. Previous SDT reply - The GVSDT thanks you for your comment. MOD-027 is written to allow for the use of ambient monitoring, recorded data associated with the normal operation of your equipment. A GO with your concerns can alleviate the issues you mention using ambient monitoring. While we agree with the reply by the SDT when ambient monitoring is available, it is not available on all of our equipment. Therefore, we stand by our previous comments.

Organization	Yes or No	Question 2 Comment
Response: The GVSDT thanks you for your comment. Ambient monitoring can be accomplished by recording the unit's MW response, when it is in a mode in which it is expected to govern. The recordings could come from a variety of source such as from plant DCS systems, recorders, SCADA data, etc. Note that for units that need to acquire recorders, slow resolution data, approximately 1 sample per second, is adequate for turbine/governor and load control or active power/frequency control function model verification.		
Wisconsin Electric Power Company	No	In Row 5, 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 we have achieved stakeholder consensus on the current proxy unit MVA threshold.** Also, in Row 6, 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 of the standard.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
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.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

Organization	Yes or No	Question 2 Comment
		Section 3 and Section 5 of the ERCOT Nodal Operating Guides.
Response: The GVSDT thanks 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 functional model and 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.		
Independent Electricity System Operator	No	The long periods in Attachment 1 introduce too much risk to modeling assumptions used to assess transmission system reliability and to make other operating and planning decisions which do not reflect or address the actual performance of the system and equipment. This standard should not only establish the maximum period that Transmission Planners and Generator Owners to complete tasks but also to require the Transmission Planners to establish more stringent requirements when necessary to reduce the risk to reliability to an acceptable level. In some jurisdictions, e.g., 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 approach has worked well. New or modified equipment must first pass through a connection assessment process to establish whether expected performance will meet connection 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 during 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
Response: The GVSDT thanks you for your comment. The time periods in Attachment 1 have been vetted through several comment		

Organization	Yes or No	Question 2 Comment
periods. Also, performance or operational requirements and the submittal of preliminary models (typically per interconnection agreements) are beyond the scope of this standard. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.		
Luminant	No	While Luminant agrees with the concepts in the periodicity requirements in Attachment 1, it would be beneficial for the drafting team to clearly identify that units that are base load (row 7) are excluded from model verification.
Response: The GVSDT thanks you for your comment. 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. The way the non-responsive unit exemption is structured will provide for base loaded units to meet the requirement with a statement regarding the unit not responding to frequency.		
ISO-New England	No	Attachment 1, Row 4 allows for transmission of a verified model 365 days after commissioning of a new generator. This is an unacceptable length of time for a generator to be on-line from both a reliability standpoint and this length of time is in conflict with ISO/RTO Standard Generator Interconnection Agreement language. The ISO/RTO Standard Generator Interconnection language requires Generator Owners to provide verified models ***prior to*** Commercial Operation.
Response: The GVSDT thanks you for your comment. This standard does not address collection of preliminary model data from the equipment manufacturer. New equipment models cannot be verified until after the equipment is available. Generator Owner development of the original model during the equipment commissioning process – including iterations with transmission entities such as the submittal of preliminary models by the Generator Owner and modifications to preliminary model data and any requirements to verify the models prior to Commercial Operations should be governed by individual interconnection agreements.		
ExxonMobil Research and Engineering	No	No comments on this question.
FirstEnergy	Yes	Although FirstEnergy (FE) agrees with the revision to Attachment 1, we feel that the capacity factor calculation in Row 8 should be a part of Applicability section 4.2

Organization	Yes or No	Question 2 Comment
		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 comment. 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. The way the capacity factor exemption is structured will provide for the requirement to be met with a statement regarding the capacity factor. It provides for an alternative way to meet the requirement, rather than a change in applicability. This will provide for more clarity in tracking the status for a given unit. 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.
Response: The GVSDT thanks you for your comment.		
Ingleside Cogeneration LP (Voting entity Occidental Chemical Corporation)	Yes	Ingleside Cogeneration LP agrees that the explanation of the periodicity requirements are an improvement over previous versions.
Response: The GVSDT thanks you for your comment.		
Southern Company	Yes	Southern Company agrees with the modifications to Attachment 1 (the Periodicity Table) as they both simplify and clarify the periodicity.
Response: The GVSDT thanks you for your comment.		
Southwest Power Pool Reliability Standards Development Team	Yes	We would suggest that there be something added to give those GO's who have not modified their plants to be able to opt out of the re-verification. There is a concern that the updated data would be at least a year out of step with the development of

Organization	Yes or No	Question 2 Comment
		the ERAG model in the eastern interconnect.
Response: The GVSDT thanks you for your comment. The processes incorporating new model data are existing processes that have proven to work well.		
Manitoba Hydro	Yes	None.
pacificorp	Yes	
Bonneville Power Administration	Yes	
Dominion	Yes	
Duke Energy	Yes	
Dynegy	Yes	
TransAlta Centralia Generation LLC	Yes	
PSEG	Yes	
Xcel Energy	Yes	
American Transmission Company	Yes	
American Electric Power	Yes	
Northeast Utilities	Yes	

Organization	Yes or No	Question 2 Comment
South Carolina Electric and Gas	Yes	
Ameren	Yes	
Chelan PUD	Yes	
Exelon Corporation and its affiliates	Yes	
Georgia Transmission Corp.	Yes	
Cowlitz PUD	Yes	

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

Summary Consideration:

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.” Also, in 5.1, the GV SDT changed the beginning of the first sentence from: “For Requirements R1, and R3 through R6 …“ to “For Requirements R1, and R3 through R5 …“ to reflect that there are five, not six requirements in the standard.

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 Date Section, “… in those jurisdictions where regulatory approval is required …” of the Implementation Plan right after, “… following applicable regulatory approval.” This was done to address regulatory approvals in Canada.

In the Applicability section 4.2.3, added the word “in” so that the phrase now reads, “Generation in the ERCOT Interconnection…” to be consistent with the language associated with the other interconnections (sections 4.2.1 and 4.2.2).

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.” Stakeholders believed that this added clarity to the Requirement.

The footnote formatting error in R4 has been corrected.

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 (R5). 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 …”

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

Organization	Question 3 Comment
	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, and 4.2.3. 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 believes 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 believes 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 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 an attestation that an event did not occur is established as an acceptable form of evidence in CAN-0030. Furthermore, precedent has been set

Organization	Question 3 Comment
	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 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.

Organization	Question 3 Comment
	Response: 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 believes 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 4 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 comment. Please see responses above.	
Ameren	(1)As a general comment, NERC should make all the papers listed in the references section of the standard readily available on their 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. **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?

Organization	Question 3 Comment
	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-027-1 while compliance with MOD-012-0 and MOD-013-1 is still in effect as explained in our response to draft MOD-026-1. We strongly request the SDT seriously consider incorporating the current MOD-012/MOD-013 submittal requirements within MOD-026 and MOD-027. 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. **MOD-012 and MOD-013 contain data submittal requirements that requires submission of the latest dynamic model data for generator, excitation system, voltage regulator, power system stabilizer and turbine-governor. MOD-027 requires model verification including submittal of the verified turbine/governor model and data.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
American Electric Power	1) In Section 4.2.3, the first line should read “Generation *in* the...”. **Response: The SDT has made the correction to the typo.** 2) In Section 5.3, the word “thirty” should be removed from the end of the fourth line. **Response: The SDT has made the correction to the typo.** 3) In Section B, Requirement R2 contains bold faced text stating “Error! Bookmark not defined.”, is this a mistake? **Response: The SDT has made the correction to the typo (should have been a footnote).** 4) MOD-027-1 R5 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:"

Organization	Question 3 Comment
	Response: Based on your and another commenter's 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 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.
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 believes 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) Requirement R4: Suggest removing the phrase "or plans . . ." and rewording as "Each Generator Owner shall provide revised model data for each applicable unit . . .." There appears to be a footnote error here - delete "6"? **Response: Regarding your first comment, the SDT purposely structured the requirement so that the Generator Owner has a choice of providing revised model data or plans to perform model verification – and the SDT allowed 180 days for the Generator Owner to make that determination. Regarding the second comment, the SDT has made the correction to the typo (should have been a footnote reference).** 3) TRE recommends changing to "Planning Authority or Transmission Planner" in the Functional 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**

Organization	Question 3 Comment
	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 believes 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 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 MW vs. frequency. 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?

Organization	Question 3 Comment
	Response: Turbine/governor and load control system model verification is well established and documented. Some of those documents are referenced in Section G of the standard. 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 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. There is a document problem with the first sentence in R4. **Response: The SDT has made the correction to the typo (should have been a footnote reference).** 7. 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

Organization	Question 3 Comment
	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.	
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 power output responses to system Disturbances. The yet-to-be-defined acceptable models may not be capable of achieving this goal, however, because standard governor component models are inadequate to predict with high fidelity the generation system response that is the subject of MOD-027-1.Take for example a combined cycle plant with the CTs at base load output and the steam turbine in the sliding pressure mode (HPT control valves wide-open). Governor-only models will show a demand for increased output if a system frequency dip is postulated; yet absolutely nothing will happen in real life, because the fuel input to the CTs is already maxed-out and the STG has no throttle reserve. The situation for a fossil unit is analogous, with non-governor-model factors such as throttle reserve, boiler thermal inertia, mill ramp rates, control valve slew rate and hysteresis, the output cap associated with going VWO, furnace and duct pressure limits, fan stall run-back routines and the like all having an impact on the outcome, depending on the time-scale involved. Sustained Disturbances with fluctuations of system frequency above and below 60 Hz pose even greater challenges, as the response characteristics of controls systems for fuel, air, drum level etc. may become temporarily destabilized. A key clarification is needed in this respect. The references in R2.1.5 to "real power response" and in R3 (3rd bull-dot) to "the recorded response" indicate that models complying with MOD-027-1 must cover the factors cited above, but R2.1.5 also speaks of elements that" override the governor response." Including in models only load control function blocks that impose a max-MW set point or otherwise modify the governor output signal may not pose a problem; but the effects of all factors that cause the actual MW response to lag or otherwise vary from the governor output demand signal can be captured only by dynamic simulators, not governor models. Simulators involve enormous cost and demand on engineering resources, and can be justified for only a handful of the

Organization	Question 3 Comment
	largest generation plants. 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-027-1 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 Page 7 of 11removed [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. short-term on-line monitoring, and controlled perturbations 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: Turbine/governor and load control system model verification is well established and documented. Some of those documents are referenced in Section G of the standard. As stated in previous postings, the SDT recognizes that governors can react differently for events that are essentially the same depending on pre-event operating conditions – the SDT believes that the Generator Owner should strive to verify a model in such a way that it represents an approximate typical response. 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**

Organization	Question 3 Comment
	transmission system beyond the point of interconnection is not required for any of the verification techniques referenced in the standard. 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 turbine / governor model used in dynamic simulation. Entities from 4 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 turbine / governor model used in dynamic simulation. 2. The complexity of the task at hand is compounded by the circumstance that generation unit response may vary widely depending on the output level at the time a BES upset occurs (as in the combined cycle example above). There are no specifics in MOD-27-1 regarding this aspect of reliability standard scope, however, just a requirement that the model shall match the actual response. The implication appears to be that a close correlation is needed for all upset magnitudes and all possible initial conditions, which brings us back to the dynamic simulator objections in comment #1 above. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. As stated in previous postings, the SDT recognizes that governors can react differently for events that are essentially the same depending on pre-event operating conditions – the SDT believes that the Generator Owner should strive to verify a model in such a way that it represents an approximate typical response. 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.** 3. There is presently no definition of how closely the model must match the recorded responseor for

Organization	Question 3 Comment
	what period of time, just a requirement that it be deemed “usable” by the TP. The SDTis asking 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. . **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The SDT believes that the term “usable” is well defined in R5. 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. Note that the SDT assumed the reference cited “to comply with MOD-026…” was meant to state “to comply with MOD-027….”** 4. R2.1.1 and the verification table in the standard allow the alternative of an on-line speedgovernor reference change test, but such testing is not always possible. Where it can beattempted there is risk of creating a larger-than-desired Disturbance, possibly threateninggrid stability or tripping the generation unit. Making GOs create Disturbances if they do notnaturally occur is not a good idea. NERC should consider directing TOPs to construct loadbanks, which they can tie-in and cut-out to jar the system for response test purposes. **Response: The SDT understands and agrees that an on-line reference change test is not available on all units as an option due to the lack of an input “port” to insert a step reference change. That is one of the reasons why this test is optional – in fact, no positive tests are required period. All Generator Owners can choose to use the ambient monitoring technique which allows the Generator Owner to wait for a frequency excursion (per Attachment 1 Note 1) – even it takes longer than the time durations stated to wait for this frequency excursion to occur with the applicable unit operating in a frequency responsive mode.** 5. R2.1.1 and the verification table also allow partial load-rejection tests. The SDT may haveenvisioned rejection to house load, followed by rapid re-synchronization, but such anoutcome

Organization	Question 3 Comment
	cannot be expected. House load is often below the minimum stable output (alwaysbelow for coal-fired and nuclear plants), and it is always far below the minimumenvironmentally-acceptable load for fuel-burning units. The need to avoid over speedfollowing load rejections meanwhile generally requires that the main steam stop valves becommanded closed at the same moment that a breaker-open signal is given.Trip testing may additionally be extremely disruptive and costly. Power Technologies, intheir paper “Testing Methods, An Overview,” states that five episodes may be required,which would be enormously expensive for combined cycle plants with a fixed dollars per tripfigure written into the long-term service agreement.Page 8 of 11Such expenditures might nonetheless be justified, if the information obtained is of sufficientvalue; but, as explained in comment #1 above, trip tests will yield data only for standardgovernor models and not for the on-line extra functions for which information is evidentlybeing sought.Footnote 2 of MOD-027-1 indicates recognition of this shortcoming. The solutions offeredhowever, “Differences between the control mode tested and the final simulation model mustbe identified,” and “some method of accounting for these differences must be presented,”are too vague and constitute no solution at all. It would be better to just admit that triptesting can’t get the job done. **Response: The SDT understands that many units are not good candidates for partial load rejection tests for the purposes of governor model verification. That is one of the reasons why this test is optional – in fact, no positive tests are required period. All Generator Owners can choose to use the ambient monitoring technique which allows the Generator Owner to wait for a frequency excursion (per Attachment 1 Note 1) – even it takes longer than the time durations stated to wait for this frequency excursion to occur with the applicable unit operating in a frequency responsive mode (Reference Row 3 of the Periodicity Table [Attachment 1]).** 6. The instruction in R4 to notify the TP, “within 180 calendar days of making changes to theturbine/governor and load control or active power/frequency control,” is too vague, despitethe attempted clarification in footnote #5, since many activities can have some degree ofimpact as noted above. Reportable thresholds regarding degree of impact on systemresponse and the expected duration are needed. Would an output power restriction due toa broken coal feeder belt be reportable, for example? **Response: The SDT believes that we have achieved stakeholder consensus on the current**

Organization	Question 3 Comment
	language of the standard. The SDT believes specifying reportable thresholds for an infinite number of possible permutations are not practical for a standard. 7. The SDT should consider moving the capacity factor exemption information found inAttachment 1, row 8 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 8 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.** 8. We recommend removing the first element of the logical AND statement of Attachment 1Row 5 (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 governor droop response vs. constant load set point) or equipment with identical design ratings, but different control system settings which would result in different models and performance).**
Response: The GVSDT thanks you for your comment. Please see responses above.	
Exelon Corporation and its affiliates	1. Exelon previously commented that MOD-027-1 R5 implies that it is the Generator Owner's responsibility to ensure that the model is "useable" based on the criteria specified in Parts 5.1

Organization	Question 3 Comment
	through 5.3; however, it is at the discretion of the Transmission Planner. As written, the requirement gives the Transmission Planner the discretion to reject the model based on governor response to a frequency deviation (positive damping) which appears to be outside of the original purpose of Project 2007-09. Exelon again reiterates that the usability of the model should not be confused with a model that accurately represents the generating unit governor and provides projected results. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. Also, the SDT believes that the Generator Owner should be positively informed from the Transmission Planner if the model is useable or not based on the criteria listed in parts 5.1 – 5.3. Also note that the Generator Owner is responsible for the model and, in accordance to the first bullet point in R3, only has to reply to the Transmission Planner if they are informed that the model is not useable. Finally, the SDT points out that the "usability" of a model does not indicate if the model accurately predicts the actual response of the equipment.** 2. Please confirm that the number of generating units combined into the percentage for implementation of unit verification includes those generating units that may have a documented exclusion such as an existing unit that does not have an installed control system. **Response: Given that this scenario is associated with Row 7 of the Periodicity Table (Attachment 1), and the Required Action column states that "Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner" then yes, it the number of generating units combined into the percentage for implementation of unit verification includes those generating units that may have a documented exclusion such as an existing unit that does not have an installed control system.** 3. MOD-027-1 R4 appears to have a formatting issue - the statement "Error! Bookmark not defined" is in bold letters within the requirement. **The SDT has made the correction to the typo (should have been a footnote reference).**
Response: The GVSDT thanks you for your comment. Please see responses above.	
Alberta Electric System	1. In section 4.2.2, The AESO considers the existing applicability for model validation to be more

Organization	Question 3 Comment
Operator	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-027 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 turbine / governor 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 turbine / governor models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying turbine / governor models, the SDT is proposing to require verification of turbine / governor 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. The AESO does not consider a partial load rejection test to be an appropriate method of model validation for base loaded units. **Response: The SDT understands that many units are not candidates for partial load rejection tests for the purposes of governor model verification. That is one of the reasons why this test is optional – in fact, no positive tests are required period. All Generator Owners can choose to use the ambient monitoring technique which allows the Generator Owner to wait for a frequency excursion (per Attachment 1 Note 1) – even it takes longer than the time durations stated to wait**

Organization	Question 3 Comment
	for this frequency excursion to occur with the applicable unit operating in a frequency responsive mode (Reference Row 3 of the Periodicity Table [Attachment 1]). 4. Requirement R4, as written it appears owners of generating units that plan to change out the governor 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.	
FirstEnergy	1.FE believes that Requirement 5 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: R5. Each Transmission Planner shall notify the Generator Owner within 90 calendar days of receiving the turbine/governor and load control or active power/frequency control system verified model information in accordance with Requirement R2 that the model is not usable (see Sub-requirements 5.1 through 5.5), 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] 5.1. The turbine/governor and load control or active power frequency control function model fails to to compute modeling data without error along with suggested areas for investigation, 5. 2. A listing of parameters that fail the Transmission Planner's data checks, 5.3. A no-disturbance simulation fails to result in non negligible transients ("flat line"), 5.4. For an otherwise stable simulation, a disturbance simulation results in the turbine/governor and load control or active power/frequency control model exhibiting an under-damped or critically damped response, or otherwise fails the Transmission Planner's stability criteria.5.5. The turbine/governor and load

Organization	Question 3 Comment
	control or active power/frequency control 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 GVSDT thanks you for your comment. The SDT believes that the level of specificity in R5 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 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. Also, the SDT feels that the Generator Owner should be positively informed from the Transmission Planner if the model is useable or not.	
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 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	

Organization	Question 3 Comment
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. All references to "real" power should be changed to "active" power to follow SI standard practice. **Response: Though the term "active power' is a SI practice, the SDT used the term "real power" to be consistent with terminology utilized in most other NERC Reliability standards.** b. One serious weakness is no there are explicit NERC performance requirements for frequency regulation. In some jurisdiction, e.g.,, Ontario, generating units are required to materially help regulate the frequency as the Transmission Planner sets performance requirements for droop, deadband and speed of response. All forms of generation are required to help regulate frequency to the extent practicable. For example, solar installations are required to reduce output during over frequency excursions. This standard in its present form allows "applicable units" to continue to not help regulate frequency could expose the BES to reliability risks. **Response: The SAR for this draft standard calls for the verification of the generator's Turbine/Governor and Load Control or Active Power/Frequency Control Function model data. Performance or operational requirements are beyond the scope of this standard.** c. In Ontario, experience has been 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 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. If the Transmission Planner requires verification only with ambient measurements, then the Generator owner should be required to do verification in this way. This concept that the Transmission Planner should decide whether submissions it receives are suitable should permeate this standard. **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**

Organization	Question 3 Comment
	be concerned with the result, which is a correct model for the equipment. The testing expert will determine the method 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. d. 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 (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** e. In Ontario, we face resistance to our standards that exceed NERC requirements. It will be very helpful if the SDT in its response offers its opinion on elements of our comments that are not incorporated into the next version of this standard? For example, 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 the continent-wide standard with additional requirements to maintain reliability in our part of the interconnection.

Organization	Question 3 Comment
	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. f. 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 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 to the Implementation Plan and Standard**
Response: The GVSDT thanks you for your comment. Please see responses above.	
American Transmission Company	ATC recommends the following changes:1. For Requirement 5, ATC recommends replacing the wording at the end of the requirement "that includes the following;" with "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. **Response: 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 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.** 2. Attachment 1, Row 7, Verification Condition column - ATC agrees with the STD intention that base load units should be exempt because they are "not responsive to frequency excursion events". However, this insinuation of base load units is too vague. Therefore, ATC recommends additional

Organization	Question 3 Comment
	wording to read "New or existing base loaded units are normally not responsive to a frequency excursion event". This makes it abundantly clear that this condition normally applies to base loaded units. **Response: The SDT believes the existing verbiage, especially the clarification in parenthesis, is very specific and unambiguous. To re-state, in order for an applicable unit to be relevant to this Row 7, the controls must be set up so that it does not operate in a frequency control mode that would result in a turbine/governor and load control or active power frequency control mode response – the exception being only during normal start up and shut down.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
Idaho Power Company	Attachment 1 - Note 1Idaho Power System Planning comments Attachment 1 discusses unit model verification to a frequency excursion using a recorded response from the generating unit. Attachment 1, Note 1 defines the frequency deviation criteria. Idaho Power System Planning asks the GVSDT to include the minimum acceptable data sampling criteria of the recording equipment as part of the Note 1 criteria. **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 required data sampling rate and other details regarding how to do the test. The focus is solely on "what" is required, not "how" it's done.** 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**

Organization	Question 3 Comment
	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.	
Cowlitz PUD	Cowlitz supports the comments from 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 power output responses to systemDisturbances. The yet-to-be-defined acceptable models may not be capable of achievingthis goal, however, because standard governor component models are inadequate to predictwith high fidelity the generation system response that is the subject of MOD-027-1.Take for example a combined cycle plant with the CTs at base load output and the steamturbine in the sliding pressure mode (HPT control valves wide-open). Governor-only modelswill show a demand for increased output if a system frequency dip is postulated; yetabsolutely nothing will happen in real life, because the fuel input to the CTs is alreadymaxed-out and the STG has no throttle reserve. The situation for a fossil unit is analogous,with non-governor-model factors such as throttle reserve, boiler thermal inertia, mill ramprates, control valve slew rate and hysteresis, the output cap associated with going VWO,furnace and duct pressure limits, fan stall run-back routines and the like all having an impacton the outcome, depending on the time-scale involved. Sustained Disturbances withfluctuations of system frequency above and below 60 Hz pose even greater challenges, asthe response characteristics of controls systems for fuel, air, drum level etc. may becometemporarily destabilized.A key clarification is needed in this respect. The references in R2.1.5 to “real powerresponse” and in R3 (3rd bull-dot) to “the recorded response” indicate that models complyingwith MOD-027-1 must cover the factors cited above, but R2.1.5 also speaks of elements that”override the governor response.” Including in models only load control function blocks thatimpose a max-MW set point or otherwise modify the governor output signal may not pose aproblem; but the effects of all factors that cause the actual MW response to lag or otherwisevary from the governor output demand signal can be captured only by dynamic simulators,not governor models. Simulators involve enormous cost and demand on engineeringresources, and can be justified for only a handful of the largest generation plants.The SDT is therefore asking for a considerable advancement in the excitation modelingstate of the art, to

Organization	Question 3 Comment
	be undertaken in parallel by the owners of every generation unit in NorthAmerica. This is a doubly daunting task in that GOs often do not have any dynamicmodeling software or expertise, much less the ability to invent something new, because thepresent approach to the subject is that GOs just provide the values of input parameters tothe 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 batterylimits. This circumstance renders them unable to model the plant-T&D interactionsassociated with Disturbances, and independent GOs may therefore forever remain unable todevelop model results that closely match actual Disturbance responses.The approach being taken in MOD-027-1 is consequently viewed as being technicallyinfeasible 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 orremoved [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, andput the new models through trial runs at several plants. These trials should be limited todata-collection means that can be non-invasively employed (e.g., short-term on-linemonitoring, and controlled perturbations during normal-stop events), and should lead todefinition of specific testing means for definition of specific model parameters. The SDTshould then put out for voting a standard requiring TOPs to own and run these models andrequiring GOs to provide them the appropriate input data, developed via the non-invasivemeans stated above. **Response: Turbine/governor and load control system model verification is well established and documented. Some of those documents are referenced in Section G of the standard. As stated in previous postings, the SDT recognizes that governors can react differently for events that are essentially the same depending on pre-event operating conditions – the SDT believes that the Generator Owner should strive to verify a model in such a way that it represents an approximate typical response. 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 for any of the verification techniques referenced in the standard. EPRI has developed software which supports**

Organization	Question 3 Comment
	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 turbine / governor model used in dynamic simulation. Entities from 4 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 turbine / governor model used in dynamic simulation. 2. The complexity of the task at hand is compounded by the circumstance that generation unitresponse may vary widely depending on the output level at the time a BES upset occurs (asin the combined cycle example above). There are no specifics in MOD-27-1 regarding thisaspect of reliability standard scope, however, just a requirement that the model shall matchthe actual response. The implication appears to be that a close correlation is needed for allupset magnitudes and all possible initial conditions, which brings us back to the dynamicsimulator objections in comment #1 above. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. 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.** 3. There is presently no definition of how closely the model must match the recorded responseor for what period of time, just a requirement that it be deemed "usable" by the TP. The SDTis asking 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

Organization	Question 3 Comment
	rulesup-front rather than addressing the matter only after a GO has attempted to comply withMOD-026 and been found lacking. . **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The SDT believes that the term "usable" is well defined in R5. 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.** 4. R2.1.1 and the verification table in the standard allow the alternative of an on-line speedgovernor reference change test, but such testing is not always possible. Where it can beattempted there is risk of creating a larger-than-desired Disturbance, possibly threateninggrid stability or tripping the generation unit. Making GOs create Disturbances if they do notnaturally occur is not a good idea. NERC should consider directing TOPs to construct loadbanks, which they can tie-in and cut-out to jar the system for response test purposes. **Response: The SDT understands and agrees that an on-line reference change test is not available on all units as an option due to the lack of an input "port" to insert a step reference change. That is one of the reasons why this test is optional – in fact, no positive tests are required period. All Generator Owners can choose to use the ambient monitoring technique which allows the Generator Owner to wait for a frequency excursion (per Attachment 1 Note 1) – even it takes longer than the time durations stated to wait for this frequency excursion to occur with the applicable unit operating in a frequency responsive mode.** 5. R2.1.1 and the verification table also allow partial load-rejection tests. The SDT may haveenvisioned rejection to house load, followed by rapid re-synchronization, but such anoutcome cannot be expected. House load is often below the minimum stable output (alwaysbelow for coal-fired and nuclear plants), and it is always far below the minimumenvironmentally-acceptable load for fuel-burning units. The need to avoid over speedfollowing load rejections meanwhile generally requires that the main steam stop valves becommanded closed at the same moment that a breaker-open signal is given.Trip testing may additionally be extremely disruptive and costly. Power Technologies, intheir paper "Testing Methods, An Overview," states that five episodes may be required,which would be enormously expensive for combined cycle plants with a fixed dollars per

Organization	Question 3 Comment
	tripfigure written into the long-term service agreement.Such expenditures might nonetheless be justified, if the information obtained is of sufficientvalue; but, as explained in comment #1 above, trip tests will yield data only for standardgovernor models and not for the on-line extra functions for which information is evidentlybeing sought.Footnote 2 of MOD-027-1 indicates recognition of this shortcoming. The solutions offeredhowever, “Differences between the control mode tested and the final simulation model mustbe identified,” and “some method of accounting for these differences must be presented,”are too vague and constitute no solution at all. It would be better to just admit that triptesting can’t get the job done. **Response: The SDT understands that many units are not candidates for partial load rejection tests for the purposes of governor model verification. That is one of the reasons why this test is optional – in fact, no positive tests are required period. All Generator Owners can choose to use the ambient monitoring technique which allows the Generator Owner to wait for a frequency excursion (per Attachment 1 Note 1) – even it takes longer than the time durations stated to wait for this frequency excursion to occur with the applicable unit operating in a frequency responsive mode (Reference Row 3 of the Periodicity Table [Attachment 1]).** 6. The instruction in R4 to notify the TP, “within 180 calendar days of making changes to theturbine/governor and load control or active power/frequency control,” is too vague, despitethe attempted clarification in footnote #5, since many activities can have some degree ofimpact as noted above. Reportable thresholds regarding degree of impact on systemresponse and the expected duration are needed. Would an output power restriction due toa broken coal feeder belt be reportable, for example? **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 are not practical for a standard.** 7. We recommend removing the first element of the logical AND statement of Attachment 1Row 5 (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.

Organization	Question 3 Comment
	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 governor droop response vs constant load set point) or equipment with identical design ratings, but different control system settings which would result in different models and performance).
Response: The GVSDT thanks you for your comment. Please see responses above.	
PPL Corporation NERC Registered Affiliates	In trying to follow the flow of this standard, it is obvious that R1 precedes R2 logically. But then it also appears that possibly R5 actually takes place before R3. **Response: It is true that R5 could take place before R3. The orders of the requirements are not meant to always reflect the chronological order of events. R3 and R4 are requirements that for the vast majority of applicable units, will never be needed.** There does not seem to be any requirement for the Transmission Planner to provide Written Comments to the GO that address the second and third bullet points of R3. It seems that a requirement should be added for the TP to provide written comments for any of the 3 bullets shown in R3; however, only the first bullet of R3 has been required of the TP (in R5) as the standard is currently written in Draft 3. **Response: In the first bullet, the interaction between Transmission Planner and Generator Owner is required to ensure that the verified model is a useable model. The last two bullets are more "peer review" in nature and as such there is not a requirement for the Transmission Planner to provide a written comment. The vast majority of the time, there will be no issue with the verified model and as such there will be no need for the Transmission Planner to develop a written comment as discussed in the second and third bullet.** The first element of the logical AND statement of Attachment 1 Row 5 (the same physical location

Organization	Question 3 Comment
	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 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.** Other minor edits: o In A.5.1 for the Effective Date, it should say R3 through R5 (not R6, as there is no R6). o Also, by footnote 4 on R4, there appears to be some sort of "Error! Bookmark" from when the footnotes were changed. **Response: The SDT agrees and have made these edits to the standard.** 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 power output responses to system Disturbances. The yet-to-be-defined acceptable models may not be capable of achieving this goal, however, because standard governor component models are inadequate to predict with high fidelity the generation system response that is the subject of MOD-027-1.Take for example a combined cycle plant with the CTs at baseload output and the steam turbine in the sliding pressure mode (HPT control valves wide-open). Governor-only models will show a demand for increased output if a system frequency dip is postulated; yet absolutely nothing will happen in real life, because the fuel input to the CTs is already maxed-out and the STG has no throttle reserve. The situation for a fossil unit is analogous, with non-governor-model factors such as throttle reserve, boiler thermal inertia, mill ramp rates, control valve slew rate and hysteresis, the output cap associated with going VWO, furnace and duct pressure limits, fan stall run-back routines and the like all having an impact on the outcome, depending on the time-scale involved. Sustained Disturbances with fluctuations of system frequency above and below 60 Hz pose even greater challenges, as the response characteristics of

Organization	Question 3 Comment
	controls systems for fuel, air, drum level etc may become temporarily destabilized. A key clarification is needed in this respect. The references in R2.1.5 to "real power response" and in R3 (3rd bull-dot) to "the recorded response" indicate that models complying with MOD-027-1 must cover the factors cited above, but R2.1.5 also speaks of elements that "override the governor response." Including in models only load control function blocks that impose a max-MW setpoint or otherwise modify the governor output signal may not pose a problem; but the effects of all factors that cause the actual MW response to lag or otherwise vary from the governor output demand signal can be captured only by dynamic simulators, not governor models. Simulators involve enormous cost and demand on engineering resources, and can be justified for only a handful of the largest generation plants. The SDT is therefore asking for a considerable advancement in the generator 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-027-1 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. short-term on-line monitoring, and controlled perturbations 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

Organization	Question 3 Comment
	above. **Response: Turbine/governor and load control system model verification is well established and documented. Some of those documents are referenced in Section G of the standard. As stated in previous postings, the SDT recognizes that governors can react differently for events that are essentially the same depending on pre-event operating conditions – the SDT believes that the Generator Owner should strive to verify a model in such a way that it represents an approximate typical response. 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 for any of the verification techniques referenced in the standard. 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 turbine / governor model used in dynamic simulation. Entities from 4 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 turbine / governor model used in dynamic simulation.** The complexity of the task at hand is compounded by the circumstance that generation unit response may vary widely depending on the output level at the time a BES upset occurs (as in the combined cycle example above). There are no specifics in MOD-27-1 regarding this aspect of reliability standard scope, however, just a requirement that the model shall match the actual response. The implication appears to be that a close correlation is needed for all upset magnitudes and all possible initial conditions, which brings us back to the dynamic simulator objections in our comments above.

Organization	Question 3 Comment
	Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. 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. There is presently no definition of 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 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. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The SDT believes that the term "usable" is well defined in R5. The SDT is not requiring an on-line speed governor reference change test – it is simply an alternative. If that technique is used, experience has proven that it does not cause a disturbance that threatens grid stability. 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.** R2.1.1 and the verification table in the standard allow the alternative of an on-line speed governor reference change test, but such testing is not always possible. Where it can be attempted there is risk of creating a larger-than-desired Disturbance, possibly threatening grid stability or tripping the generation unit. Making GOs create Disturbances if they do not naturally occur is not a good idea. NERC should consider directing TOPs to construct load banks, which they can tie-in and cut-out to jar the system for response test purposes. **Response: The SDT understands and agrees that an on-line reference change test is not available on all units as an option due to the lack of an input "port" to insert a step reference change. That**

Organization	Question 3 Comment
	is one of the reasons why this test is optional – in fact, no positive tests are required period. All Generator Owners can choose to use the ambient monitoring technique which allows the Generator Owner to wait for a frequency excursion (per Attachment 1 Note 1) – even it takes longer than the time durations stated to wait for this frequency excursion to occur with the applicable unit operating in a frequency responsive mode. R2.1.1 and the verification table also allow partial load-rejection tests. The SDT may have envisioned rejection to house load, followed by rapid re-synchronization, but such an outcome cannot be expected. House load is often below the minimum stable output (always below for coal-fired and nuclear plants), and it is always far below the minimum environmentally-acceptable load for fuel-burning units. The need to avoid overspeed following load rejections meanwhile generally requires that the main steam stop valves be commanded closed at the same moment that a breaker-open signal is given. Trip testing may additionally be extremely disruptive and costly. Power Technologies, in their paper "Testing Methods, An Overview," states that five episodes may be required, which would be enormously expensive for combined cycle plants with a fixed dollars per trip figure written into the long-term service agreement. Such expenditures might nonetheless be justified, if the information obtained is of sufficient value; but, as explained in our comments above, trip tests will yield data only for standard governor models and not for the on-line extra functions for which information is evidently being sought. Footnote 2 of MOD-027-1 indicates recognition of this shortcoming. The solutions offered however, "Differences between the control mode tested and the final simulation model must be identified," and "some method of accounting for these differences must be presented," are too vague and constitute no solution at all. It would be better to just admit that trip testing can't get the job done. **Response: The SDT understands that many units are not good candidates for partial load rejection tests for the purposes of governor model verification. That is one of the reasons why this test is optional – in fact, no positive tests are required period. All Generator Owners can choose to use the ambient monitoring technique which allows the Generator Owner to wait for a frequency excursion (per Attachment 1 Note 1) – even it takes longer than the time durations stated to wait for this frequency excursion to occur with the applicable unit operating in a frequency responsive mode (Reference Row 3 of the Periodicity Table [Attachment 1]).**

Organization	Question 3 Comment
	The instruction in R4 to notify the TP, "within 180 calendar days of making changes to the turbine/governor and load control or active power/frequency control," is too vague, despite the attempted clarification in footnote #5, 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. Would an output power restriction due to a broken coal feeder belt be reportable, for example? **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 are not practical for a standard.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
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 frequency transients can lead to reliability improvements. In addition, the technical language used in the latest version of MOD-027-1 has been refined to an acceptable point in our view. 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 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

Organization	Question 3 Comment
	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 comment. 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-027 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.	
JEA	JEA supports the comments of the NAGF and believes that the SDT team should accept a request by the NAGF to have a joint meeting to discuss and resolve the many differences since these differences are so substantial that the usual iterative process will be excessively long. We also support NAGF's suggestion to evaluate these standards using the Cost Effective Analysis Process.
Response: The GVSDT thanks you for your comment. The GVSDT did not receive any comments from the NAGF, however others have mirrored the intent to concur with their comments (see specifically Cowlitz). We have responded to those comments above. All reliability standards undergo an economic analysis by the FERC during the NOPR process.	
Chelan PUD	Note 2, Page 4: It is unclear what would constitute and acceptable accounting - "Some method of accounting for these differences must be presented..." Unless any accounting would be acceptable, suggest some guidance.
Response: The GVSDT thanks you for your comment. Based on a review of the Field Test results and experience of the SDT members, the SDT recognized that it was not desirable to develop a dynamic model verification Standard like a technical	

Organization	Question 3 Comment
procedure manual. Such a strategy would fail as there is a wide range of equipment that will need to be verified. Thus, the SDT drafted a Standard that concentrates on "stating what is required" but without "stating how to accomplish what is required" so that the details can be managed by the modeling verification expert.	
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: The GVSDT thanks 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 Planner could delegate the responsibility to another such as its Planning Authority.	
Manitoba Hydro	R1 - The text would be more clear if rewritten to read 'Within 90 calendar days of receiving a written request, each Transmission Owner shall provide to its requesting Generator Owner:' **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."** 4.2 - The language immediately preceding the bullets is unclear: 'that meet the following' should perhaps be rewritten as 'provided they meet the following'. **If one removes the other parts of the sentence (stand alone phrases), the current language coveys "facilities that meet the following." The SDT believes that terminology conveys the intent. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.** Effective Date Section 5.1 - Manitoba Hydro recommends changing the "R6" to "R5" because there

Organization	Question 3 Comment
	is no "R6" in the standard. **The SDT thanks you for catching this typo. The SDT has corrected the type.** 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? **The SDT is proposed Implementation Plan allows the Generator Owner time to develop in-house expertise to perform model verification if they do not desire to hire consultants. 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.	
ReliabilityFirst	ReliabilityFirst votes in the Negative for the draft MOD-027-1 standard since 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."**

Organization	Question 3 Comment
	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 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 previous postings of the draft MOD-027 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**

Organization	Question 3 Comment
	dynamic simulations, while not unduly mandating costly and time consuming verification efforts. **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 comment. Please see responses above.	
Seattle City Light	Requirement 2.1.1 states three separate ways to verify MW response for a synchronous generator, but uses the term "either of" when referring to the choice of tests, which implies two tests. Please clarify with either two tests or change the reference to "any of." In addition, one of the tests of 2.1.1 includes a partial load rejection. Such a test is already part of the Kestrel test procedures currently performed by Seattle City Light. It is not clear from the requirement and footnote if our existing test would be sufficient for validation or if the other two tests would also be required. Please clarify the language of R2.1.1.
Response: The GVSDT thanks you for your comment. The use of a bullet lists in R2.1.1 conforms to standard development protocol. Specifically, a bullet list indicates the entity selects which of the listed actions is appropriate to perform. Additionally the use of the phrases "either" at the end of the root requirement, followed by a comma at the end of the first bullet, the word "or" at the end of the second bullet emphasizes that one of the three test results can be utilized. Only one of the three bulleted activities has to occur for compliance – as such, if an entity has utilized a partial load rejection test and satisfied the corresponding footnote, then that would satisfy what is required from R2.1.1. For the above stated reasons, the SDT believes that it has achieved stakeholder consensus on the current language of the standard.	
Dynegy	Some smaller Generator Owners have little experience in this type of testing. If possible, it is suggested more detail be placed in Attachment 1 regarding what constitutes an acceptable test, i.e., template.
Response: The GVSDT thanks you for your comment. Based on a review of the Field Test results and experience of the SDT members, the SDT recognized that it was not desirable to develop a dynamic model verification Standard like a technical procedure manual. Such a strategy would fail as there is a wide range of equipment that will need to be verified. Thus, the SDT	

Organization	Question 3 Comment
drafted a Standard that concentrates on "stating what is required" but without "stating how to accomplish what is required" so that the details can be managed by the modeling verification expert.	
Tennessee Valley Authority	Step 4.2.3, Recommend adding "in" to the requirement to read "Generation in the ERCOT Interconnection ..." Justification is to be consistent with similar steps 4.2.1 and 4.2.2.
Response: The GVSDT thanks you for your comment. The SDT has corrected the typo.	
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. **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 achieved stakeholder consensus on the current language of the standard.**
Response: The GVSDT thanks you for your comment.	
Southern Company	The SDT should consider moving the capacity factor exemption information found in Attachment 1, row 8 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 8 of Attachment 1 to be deleted.

Organization	Question 3 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. The way the capacity factor exemption is structured will provide for the requirement to be met with a statement regarding the capacity factor. It provides for an alternative way to meet the requirement, rather than a change in applicability. This will provide for more clarity in tracking the status for a given unit. The SDT believes that we have achieved stakeholder consensus on the current language of the standard. Requirement R4 has a problem with the bookmark "Error! Bookmark not defined". **Response: Thank you for pointing out this error. The footnote designation has been corrected.** We recommend removing the first element of the logical AND statement of Attachment 1 Row 5 (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).**
Response: The GVSDT thanks you for your comment. Please see responses above.	
Dominion	There appears to be a mismatch between Requirement R2 and the Effective Date statements. Specifically, R2 is applied on an "applicable unit" bases where the Effective Date statements are applied on an "applicable unit gross MVA" basis.R4; **Response: The language in R2 refers back to the Applicability / Facilities definition of "applicable unit." The effective dates determine the quantity of units to be verified for each Effective Date –**

Organization	Question 3 Comment
	and that quantity is based on an "applicable unit gross MVA" basis. bookmark #4 in the clean version needs to be corrected, shows 'Error! Bookmark not defined. **Response: Thank you for pointing out this error. The footnote designation has been corrected.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
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 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 achieved stakeholder consensus on the current language of the standard.	
NIPSCO	Verification requirements would be burdensome, e.g., model response by a load rejection test or comparison with a system frequency excursion 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.

Organization	Question 3 Comment
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. Note that the use of load rejection test is only an option that does not have to be utilized by the Generator Owner. Also, the SDT believes that the recording of units real power output while they are in operating in a frequency responsive mode during a system frequency excursion that meets or exceeds the criteria in Attachment 1 Note 1 is of great value and can be used to verify the model. Finally, The SDT understands that many units are not good candidates for partial load rejection tests for the purposes of governor model verification. That is one of the reasons why this test is optional.	
Duke Energy	We recommend removing the first element of the logical AND statement of Attachment 1 Row 5 (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 comment. 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).	
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)

Organization	Question 3 Comment
	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. **Response: Note that modeling of synchronous condensers is not applicable to MOD-027. Synchronous condensers are implemented for dynamic voltage control and are not part of any turbine/governor equipment.** 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

Organization	Question 3 Comment
	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 receiving a request for it. **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. There are already processes in place which facilitate the sharing of the most current dynamic models through MOD-012 and 013. In the eastern interconnection, dynamic models are shared in part through the MMWG.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
ISO-New England	Attachment 1, Row 8 has a reference to capacity factor. The capacity factor section has been removed from the body of the standard. If the capacity factor is still part of the standard by it's existence in the Attachment then this is unacceptable. Older large units with low capacity factors will be called upon to operate during extreme weather events when the system is most stressed. System reliability will be compromised if the modeled characteristics of the units differ from what is actually installed in the field. **Response: The SDT believes that there is little reliability to be gained by testing units with capacity factor of less than 5%. The added cost of testing is not justified. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.** 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**

Organization	Question 3 Comment
	that generator owners without software licenses can receive the block diagrams and data sheets. Requirement R3 might only require a "written response" from a Generator Owner to the Transmission Planners notification that a model is not useable with some technical basis for keeping the current model that is not usable. 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 R5 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 believes that we have achieved stakeholder consensus on the current language of the standard. Also, the SDT feels that the Generator Owner should be positively informed from the Transmission Planner if the model is useable or not.**
Response: The GVSDT thanks you for your comment. Please see responses above.	

END OF REPORT