NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Generator Verification (MOD-027-1) — Project 2007-09

The Generator Verification Drafting Team thanks all commenters who submitted comments on the First Posting of MOD-027-1, Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions (Project 2007-09). These standards were posted for a 30-day public comment period from June 15, 2011 through July 15, 2011. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 65 sets of comments, including comments from approximately 182 different people from approximately 95 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html

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 of Standards and Training, Herb Schrayshuen, at 404-446-2563 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration:

The GVSDT expanded the applicability of MOD-027-1 to include plants/facilities comprised of multiple small units such as variable energy resource plants/facilities. Stakeholders were asked whether they were aware of other generation configurations or types that should be covered in the Applicability. The vast majority of industry agrees that all of generation configurations or types that should be included in the Applicability section are specified in the current draft of the standard. A few minority comments were received suggesting that the Applicability section proposed should either be expanded or reduced. The SDT believes industry supports the current draft of the proposed applicability.

The GVSDT did not propose a Requirement in MOD-027-1 where the Planning Coordinator can request a review of a turbine/governor and load control or active power/frequency control system model for a unit not specified in the standard Applicability section. This was discussed in relation to the proposed MOD-026-1 where a Planning Coordinator may request information on an excitation control system model for a technically justified unit. The GVSDT does not believe that it is likely that the turbine/governor and load control or active power/frequency control system will contribute to a stability limit, and governor response is not consistent from one frequency excursion event to the next. Stakeholders were asked if they agreed with this approach. The majority of industry comments support the GVSDT proposal not to include a Requirement allowing the Planning Coordinator to request a model review for a unit not specified in the standard Applicability section. There is minority opinion suggesting that such a Requirement should be developed; with some commenters also questioning the basis for the Applicability section and the capacity factor philosophy. Most of the minority comments were received from one Reliability Region and as such the GVSDT suggests that region should consider developing a

[1] The appeals process is in the Standard Processes Manual:
http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_Rev%201_20110825.pdf

Regional Standard containing a more stringent Applicability. The Planning Coordinator can still request a model review however, the review is not mandatory under the standard requirements.

Based on industry comments received, the following modifications to the proposed standard have been made by the GVSDT:

1) Corrections of various typos in the body of the standard, the VSLs, and in Attachment 1

2) Extended the time to comply with Requirement 1 from 30 to 90 days

3) Modified Attachment 1 (Periodicity Table) to address units which are always base loaded (by definition a base loaded unit is considered verified).

4) Modified Attachment 1 (Periodicity Table) to clarify establishing the Initial Ten Year Unit Verification Period Start Date

5) Reduced the maximum time allowed between capture of an event and completing model verification from two years to one year.

6) Referenced the NERC GADS document for references to capacity factor in the draft standard.

7) Included partial load rejection as a potential test to obtain a recording of the equipment response to be used in model verification.

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	Brent Ingebrigtson	LG&E and KU Energy	X		X		X	X				
No additional members listed.													
2.	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.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity 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.	Brian Evans-Mongeon	Utility Services	NPCC	8
8.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
9.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
10.	Kathleen Goodman	ISO - New England	NPCC	2

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
11.	Chantel Haswell	FPL Group, Inc.	NPCC	5
12.	David Kiguel	Hydro One Networks Inc.	NPCC	1
13.	Michael R. Lombardi	Northeast Utilities	NPCC	1
14.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
19.	Saurabh Saksena	National Grid	NPCC	1
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
3.	Group	Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tino Zaragoza	IID	WECC	1
2.	Sammy Alcaraz	IID	WECC	3
3.	Diana Torres	IID	WECC	4
4.	Marcela Caballero	IID	WECC	5
5.	Cathy Bretz	IID	WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Albert DiCaprio	IRC Standards Review Committee (joint comments)		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Terry Bilke	MISO	RFC	2
2.	Patrick Brown	PJM	RFC	2
3.	Ben Li	IESO	NPCC	2

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

4.	Mark Thompson	AESO	WECC	2
5.	Steve Myers	ERCOT	ERCOT	2

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	David Thorne	Pepco Holdings Inc Affiliates	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carl Kinsley	Pepco Holdings Inc	RFC	1, 3
2.	Alivan Depew	Pepco Holdings Inc	RFC	1, 3

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Jonathan Sykes, Chair	NERC System Protection and Control Subcommittee	X			X	X					X

No additional members listed.

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Carol Gerou	Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	Omaha Public Power Dist	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6
4.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
5.	Ken Goldsmith	Alliant Energy	MRO	4
6.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
7.	Dave Rudolph	Basin Electric Power Copperative	MRO	1, 3, 5, 6
8.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
9.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
10.	Joseph DePoorter	Madison Gas and Electric Company	MRO	3, 4, 5, 6
11.	Scott Nichols	Rochester Public Utilities	MRO	4
12.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6
13.	Richard Burt	Minnkota Power Cooperative	MRO	1, 3, 5, 6

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

14. Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5
15. Scott Bos	Muscatine Power and Water	MRO	3, 4, 5, 6
16. Lee Kittleson	Otter Tail Power Company	MRO	5, 1, 3, 6
17. Marie Knox	Midwest ISO	MRO	2

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

Additional Member	Additional Organization	Region	Segment Selection
1. Paul Reynolds	Sunflower Electric Power Corporation	SPP	1
2. Valerie Pinamonti	AEP	SPP	1, 3, 5
3. Bud Averill	Grand River Dam Authority	SPP	1, 3, 5
4. Clem Cassmeyer	Western Farmers Electric Cooperative	SPP	1, 3, 5
5. Louis Guidry	CLECO	SPP	1, 3, 5
6. Sean Simpson	McPhearson Board of Public Utilities	SPP	1, 3, 5
7. Robert Rhodes	SPP	SPP	2

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

Additional Member	Additional Organization	Region	Segment Selection
1. John Sullivan	Ameren Services Co.	SERC	1
2. James Manning	NC Electric Membership Corp.	SERC	1
3. Philip Kleckley	SC Electric & Gas Co.	SERC	1
4. Pat Huntley	SERC Reliability Corp.	SERC	10
5. Bob Jones	Southern Company Services	SERC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Tim Brown	Idaho Power-Power Production					X					

Additional Member	Additional Organization	Region	Segment Selection
1. Guy Colpron	Idaho Power	WECC	5
2. Mark Pfeifer	Idaho Power	WECC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
11.	Group	Terry L. Blackwell	Santee Cooper	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	S. T. Abrams	Santee Cooper	SERC	1
2.	Phil Pierce	Santee Cooper	SERC	5
3.	Paul Camilletti	Santee Cooper	SERC	5
4.	Rene Free	Santee Cooper		1
5.	Tom Curtis	Santee Cooper	SERC	5

				1	2	3	4	5	6	7	8	9	10
12.	Group	Annette Bannon	PPL Generation					X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Leland McMillan	PPL Montana, LLC	WECC	5
2.	Don Lock	Lower Mount Bethel Energy, LLC	RFC	5
3.		PPL Brunner Island, LLC	RFC	5
4.		PPL Holtwood, LLC	RFC	5
5.		PPL Martins Creek, LLC	RFC	5
6.		PPL Montour, LLC	RFC	5

				1	2	3	4	5	6	7	8	9	10
13.	Group	Louis Slade	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Garton		MRO	5, 6
2.	Connie Lowe		SERC	5, 6
3.	Michael Gildea		RFC	5, 6
4.	Larry Whanger		SERC	5
5.	Mike Crowley		SERC	1, 3
6.	Jeff Bailey		MRO	5

				1	2	3	4	5	6	7	8	9	10
14.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	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.	Ed Baznik	FE	RFC	1
2.	Bill Duge	FE	RFC	5
3.	Brian Orians	FE	RFC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	Joe Spencer - SERC Bob Jones - DRS chair	SERC Dynamics Review Sub-committee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Robin Wells - vice chair	LG&E/KU	SERC	
2.	Kumar Mani	Progress Energy	SERC	
3.	Bill Shultz	Southern Co.	SERC	
4.	Tom Higgins	Southern Co.	SERC	
5.	Brad Haralson	AECI	SERC	
6.	Terry Crawley	Southern Co.	SERC	
7.	Chris Georgeson - chair	Progress Energy	SERC	
8.	Tracey Stubbs	Entergy	SERC	
9.	Paul Palmer	TVA	SERC	
10.	David Thompson	TVA	SERC	
11.	Jules Guillot	Entergy	SERC	
12.	Matt Wallace	Ameren	SERC	
13.	Joe Spencer	SERC Reliability Corp.	SERC	

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Group	Mallory Huggins	NERC Staff										

No additional members listed.

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17.	Group	John Seelke	Public Service Enterprise Group	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ken Brown	PSE&G	RFC	1, 3
2.	Clint Bogan	PSEG Fossil	RFC	5

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

3. Peter Dolan	PSEG ER&T	RFC	6
4. Scott Slickers	PSEG Fossil	NPCC	5
5. Eric Schmidt	PSEG ER&T	NPCC	6
6. Mikhail Falkovich	PSEG Fossil	ERCOT	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18. Group	Joe Spencer - SERC staff	SERC Generation sub-committee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Robin Wells - vice chair	LG&E/KU	SERC	
2.	Kumar Mani	Progress Energy	SERC	
3.	Bill Shultz	Southern Co.	SERC	
4.	Tom Higgins	Southern Co.	SERC	
5.	Brad Haralson	AECI	SERC	
6.	Terry Crawley	Southern Co.	SERC	
7.	Chris Georgeson - chair	Progress Energy	SERC	
8.	Tracey Stubbs	Entergy	SERC	
9.	Paul Palmer	TVA	SERC	
10.	David Thompson	TVA	SERC	
11.	Jules Guillot	Entergy	SERC	
12.	Matt Wallace	Ameren	SERC	
13.	Joe Spencer	SERC Reliability Corp.	SERC	

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
19. Group	Jason Marshall	ACES Power Members						X				

Additional Member	Additional Organization	Region	Segment Selection
1. James Jones	AEPCO/SWTC	WECC	1, 3, 5
2. Mohan Sachdeva	Buckeye Power	RFC	4, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
20. Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
21.	Individual	Bo Jones	Westar Energy	X		X		X	X				
22.	Individual	Antonio Grayson	Southern Company					X					
23.	Individual	David Thompson	Tennessee Valley Authority GO					X					
24.	Individual	David Youngblood	Luminant Power					X					
25.	Individual	David Miller	Lakeland Electric	X									
26.	Individual	Cynthia Oder	Salt River Project	X		X		X	X				
27.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
28.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
29.	Individual	Edward Cambridge	APS	X		X		X					
30.	Individual	Brad Haralson	Associated Electric Cooperative, Inc.	X		X		X	X				
31.	Individual	Dan Roethemeyer	Dynegy Inc.					X					
32.	Individual	Greg Campoli	New York Independent System Operator		X								
33.	Individual	Samuel Reed	Tri-State Generation and Transmission, In.	X				X					
34.	Individual	Russell A. Noble	Cowlitz County PUD			X	X	X					
35.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
36.	Individual	Mace Hunter	Lakeland Electric	X		X		X					
37.	Individual	John Bee	Exelon	X		X		X					
38.	Individual	Michael Goggin	American Wind Energy Association								X		
39.	Individual	Keith Morisette	Tacoma Power	X		X	X	X	X				
40.	Individual	Bob Casey	Georgia Transmission Corporation	X									
41.	Individual	Jeanie Doty	Austin Energy					X					
42.	Individual	Dale Fredrickson	Wisconsin Electric			X	X	X					
43.	Individual	Michael Brytowski	Great River Energy	X		X		X					
44.	Individual	Vladimir Stanisic	BC Hydro	X	X	X		X					
45.	Individual	Michael Lombardi	Northeast Utilities	X		X		X					
46.	Individual	Amir Hammad	Constellation Power Generation					X					
47.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
48.	Individual	Thad Ness	American Electric Power	X		X		X	X				
49.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP					X					
50.	Individual	Hamish Wong	Wisconsin Public Service Corp			X	X	X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
51.	Individual	Gary Chmiel	GE Energy										
52.	Individual	Kathleen Goodman	ISO New England		X								
53.	Individual	Dan Hansen	GenOn Energy					X					
54.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
55.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
56.	Individual	Eric Ruskamp	Lincoln Electric System	X		X		X	X				
57.	Individual	Jose H Escamilla	CPS Energy			X							
58.	Individual	Michael Falvo	Independent Electricity System Operator		X								
59.	Individual	Karen Alford	Gainesville Regional Utilities	X		X		X					
60.	Individual	Kirit Shah	Ameren	X		X		X	X				
61.	Individual	Rex Roehl	Indeck Energy Services					X					
62.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X									
63.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
64.	Individual	Oscar Herrera	Los Angeles Department of Water and Power	X		X		X	X				
65.	Individual	John Yale	Chelan County PUD	X				X	X				

1. The Applicability section of MOD-027 standard is expanded to include plants/facilities comprised of multiple small units such as variable energy resource plants/facilities. Are you aware of other generation configurations/types that should be covered in the Applicability?

Summary Consideration: The vast majority of industry agrees that all generation configurations/types that should be included in the Applicability section are specified in the current draft of the standard. There was some confusion regarding the treatment of small units at plants. The SDT in response revised the Applicability to include plants greater than X MVA that have units with ratings less than 20 MVA (X is 100 for Eastern and Qubec, 75 for WECC, and 75 for ERCOT). The SDT believes that this revised applicability Section language is clearer while at the same time it still captures the appropriate units and plants for model verification (i.e., greater than 80% of interconnected VER plants for each Interconnection). A few minority comments were received suggesting that the Applicability section proposed should either be expanded or reduced. The SDT believes industry supports the current draft of the Applicability section proposed.

Organization	Yes or No	Question 1 Comment
LG&E and KU Energy		
Northeast Power Coordinating Council	No	
Imperial Irrigation District (IID)	No	
IRC Standards Review Committee (joint comments)		
Pepco Holdings Inc Affiliates		
NERC System Protection and Control Subcommittee		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	No	

Organization	Yes or No	Question 1 Comment
SPP Reliability Standards Development Team	No	By setting the MVA rating at 100MVA in section 4.2.1 for single units aren't you excluding units? It is then mentioned in the bullet below that units below 20MVA are included but as an aggregate if the site is over 100MVA. We aren't clear how this is expanding the standard. The other standards in this group refer to the limits used in the Compliance Registry. Should this be consistent with those?
Response: Thank you for your comment. The SDT believes it is unnecessary to require all units in the compliance registry to have verified models. However, it is useful to have verified models for at least 80% of the connected MVA in the interconnection and as such the SDT has specified in the Applicability section gross nameplate rating size requirements for each interconnection for achieving this threshold. Given the increasing importance of renewable generation plants comprised of several small units, the SDT also proposes requiring verification of these plants and has added language to the Applicability section to capture this intent. Also, the SDT revised the Applicability to include plants greater than X MVA that have units with ratings less than 20 MVA (X is 100 for Eastern and Quebec, 75 for WECC, and 75 for ERCOT). Note that "X" is 100 for the Eastern and Quebec Interconnections, 75 for WECC and ERCOT. The SDT believes that this revised applicability Section language is clearer while at the same time capturing the appropriate units and plants for model verification (i.e., greater than 80% of interconnected VER plants for each Interconnection).		
SERC Planning Standards Subcommittee		
Idaho Power-Power Production	Yes	We believe Black Start units, regardless of size, should be considered in this standard.
Response: Thank you for your comment. Turbine/Governor and Load Control or Active Power/Frequency Control models are less important for a black start unit emergency power source because these units are not typically modeled in planning studies. When needed, these units are started in asynchronous mode to power black start unit auxiliaries and are not configured to control grid frequency.		
Santee Cooper		
PPL Generation	No	
Dominion	No	
FirstEnergy	No	

Organization	Yes or No	Question 1 Comment
SERC Dynamics Review Sub-committee	No	The DRS agrees that the intended generating units would be covered by reasonable interpretation of the applicability section 4.2. However, the DRS recommends that footnote 3 be changed to read "The common transmission voltage level bus (i.e. 100 kV or greater) to which the step up transformer(s) is connected." This more clearly includes "step up" transformers for some types of variable energy plants which may not be "generator step up" transformers.
Response: Thank you for your comment. The SDT agrees and has removed the footnote and revised the applicability for clarity.		
NERC Staff	No	We are not aware of other units types at this time, but the applicability should be written broadly enough to not preclude applicability to other types of resources that may be connected in the future.
Response: Thank you for your comment. The SDT believes that the Applicability section is technology neutral.		
Public Service Enterprise Group	No	
SERC Generation sub-committee		
ACES Power Members	No	
Arizona Public Service Company	Yes	
Westar Energy	No	We suggest for consistency with the other standards in this project that this standard also reference the limits used in the Compliance Registry.
Response: Thank you for your comment. The SDT believes it is unnecessary to require all units in the compliance registry to have verified models. However, it is useful to have verified models for at least 80% of the connected MVA in the interconnection and as such the SDT has specified in the Applicability section gross nameplate rating size requirements for each interconnection for achieving this threshold.		
Southern Company	No	1) We are not convinced that wind plants need to be included at all due to a) the uncertainty of the wind availability during a frequency excursion and b) the transient nature of any contribution that the a wind turbine may be able to provide to correct or affect the frequency excursion. It is believed that the time

Organization	Yes or No	Question 1 Comment
		frame of the frequency excursion will far exceed the wind turbine's ability to sustain a correcting action. 2) It is our opinion that a 20MVA machine is too small to be able to significantly impact a frequency perturbation. A technical basis for including units as small as 20MVA in all regions needs to be provided. NERC is focusing on standard requirements that have significant impacts on system reliability, and including units this small seems to be inconsistent with this philosophy.
Response: Thank you for your comment. The SDT has added another row to Attachment 1 (the Periodicity Table) defining requirement exceptions for units that cannot control frequency such as a significant number of wind plants. For the Eastern Interconnection, 20 MVA rated units only have to be verified if they are part of a plant that is 100 MVA or greater. The SDT believes that 100 MVA plants in the Eastern Interconnection are significant. Also, the unit Applicability for this standard is already a subset of the Compliance Registry.		
Tennessee Valley Authority GO	No	
Luminant Power	No	
Lakeland Electric		
Salt River Project	Yes	
PacifiCorp	No	
South Carolina Electric and Gas	No	
APS		being intentionally left blank (no answer to be provided)
Associated Electric Cooperative, Inc.	No	
Dynegy Inc.	No	
New York Independent System		

Organization	Yes or No	Question 1 Comment
Operator		
Tri-State Generation and Transmission, In.	No	
Cowlitz County PUD	No	
Xcel Energy	No	
Lakeland Electric		
Exelon		
American Wind Energy Association	No	
Tacoma Power	No	None
Georgia Transmission Corporation	No	
Austin Energy	No	
Wisconsin Electric	No	
Great River Energy		
BC Hydro	No	
Northeast Utilities	No	

Organization	Yes or No	Question 1 Comment
Constellation Power Generation	No	No. CPG believes that the use of capacity factor, a variable data point, in the applicability of a standard is too problematic. Capacity factor is a market a function that is dependent on many variables outside of reliability and therefore does not belong in a reliability standard. CPG is also unsure as to how the SDT arrived at the MVA thresholds in each of the Interconnections, and is requesting that a technical justification of those thresholds be submitted along with the response of comments.
Response: Thank you for your comment. The 5% capacity factor exemption was selected to achieve a balance between the cost and benefits. The SDT believes that there are a limited number of units greater than 100 MVA with a capacity factor of less than 5%. Also, units with a capacity factor of less than 5% are excluded from model verification however other standards still require that the data be supplied. The SDT believes it is not necessary to require all units in the compliance registry to have models verified. The SDT also believes that the applicability section thresholds specified will result in substantial accuracy improvement to the governor models and associated Reliability based limits determined by dynamic simulations, while not unduly mandating costly and time consuming verification efforts. As a basis, the SDT recognized that the governor 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 initiated by the Phase III-IV SDT, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the governor models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying governor models, the SDT is proposing to require verification of governor models associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA thresholds which the SDT believes corresponds to 80% of connected MVA or greater for each Interconnection are proposed. Given the increasing importance of renewable generation plants comprised of several small units, the SDT also proposes requiring verification of these plants and has added language to the Applicability section to capture this intent. Please note the calculation of capacity factor is specified in Appendix F of the GADS Data Reporting Instructions on the NERC website.		
Consolidated Edison Co. of NY, Inc.	No	
American Electric Power	No	
Ingleside Cogeneration LP	No	
Wisconsin Public Service Corp	No	
GE Energy		

Organization	Yes or No	Question 1 Comment
ISO New England	Yes	Generators sized well over 100 MVA with a capacity factor under 5% are numerous in our area of the Eastern Interconnection. These older large generators with a capacity factor below 5% will have a significant impact on electric system performance during stressed conditions with high loads. These generators must not be excluded from the verification requirement. Generators sized under 100 MVA may also be important, what is the justification for the cutoff from the verification requirement at 100 MVA? This applicability criteria in this standard should be the same as the Compliance Registry requirements.
Response: Thank you for your comment. The 5% capacity factor exemption was selected to achieve a balance between the cost and benefits. The SDT believes that there are a limited number of units greater than 100 MVA with a capacity factor of less than 5%. Also, units with a capacity factor of less than 5% are excluded from model verification however other standards still require that the data be supplied. The SDT believes it is not necessary to require all units in the compliance registry to have models verified. The SDT also believes that the applicability section thresholds specified will result in substantial accuracy improvement to the governor models and associated Reliability based limits determined by dynamic simulations, while not unduly mandating costly and time consuming verification efforts. As a basis, the SDT recognized that the governor 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 initiated by the Phase III-IV SDT, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the governor models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying governor models, the SDT is proposing to require verification of governor models associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA thresholds which the SDT believes corresponds to 80% of connected MVA or greater for each Interconnection are proposed. Given the increasing importance of renewable generation plants comprised of several small units, the SDT also proposes requiring verification of these plants and has added language to the Applicability section to capture this intent.		
GenOn Energy	No	
Manitoba Hydro	No	
Duke Energy	No	We are not convinced that wind plants need to be included at all due to a) the uncertainty of the wind availability during a frequency excursion and b) the transient nature of any contribution that the a wind turbine may be able to provide to correct or affect the frequency excursion. It is believed that the time frame of the frequency excursion will far exceed the wind turbine's ability to sustain a correcting action.
Response: Thank you for your comment. The SDT has added another row to Attachment 1 (the Periodicity Table) defining requirement exceptions for units		

Organization	Yes or No	Question 1 Comment
that cannot control frequency, which includes a significant number of wind plants.		
Lincoln Electric System		
CPS Energy		
Independent Electricity System Operator	No	No, we are not aware of any, but the Applicability Section of the draft standard does not contain specific references to variable energy resource plants/facilities. It only covers generating units and plants of certain sizes for the three (and Quebec) Interconnections without any specificity on generator types. Was it an oversight or did the SDT suggest that the "generating units" suffice to generally include all types of energy resources?
Response: Thank you for your comment. The SDT is developing a technology neutral standard that covers all current and future technologies.		
Gainesville Regional Utilities	No	
Ameren	No	
Indeck Energy Services		
Oncor Electric Delivery Company LLC	No	
Indiana Municipal Power Agency		
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Chelan County PUD	No	

2. Because it is not likely that the turbine/governor and load control or active power/frequency control system will contribute to a stability limit, and because governor response is not consistent from one frequency excursion event to the next, the SDT is not proposing a Requirement in MOD-027-1 where the Planning Coordinator can request a review of a turbine/governor and load control or active power/frequency control system model for a unit not specified in the standard Applicability section.

Do you agree with the proposal to not include a Requirement in MOD-027-1 where the Planning Coordinator can request a review of a turbine/governor and load control or active power/frequency control system model for a unit not specified in the standard Applicability section?

Summary Consideration: The majority of industry comments support the SDT proposal not to include a Requirement allowing the Planning Coordinator to request a model review for a unit not specified in the standard Applicability section. There is minority opinion suggesting that such a Requirement should be developed; with some commenters also questioning the basis for the Applicability section and the capacity factor philosophy. Most of the minority comments were received from one Reliability Region and as such that region should consider developing a Regional standard containing a more stringent Applicability. The Planning Coordinator can still request a model review however the review is not mandatory by standard requirements.

Organization	Yes or No	Question 2 Comment
LG&E and KU Energy		
Northeast Power Coordinating Council	No	A Planning Coordinator should be able to request a review of turbine/governor and load control or active power/frequency control system model even though response is not consistent from one frequency excursion event to the next from any unit connected to the power system. If not being listed in the Applicability section is an issue, then the wording should be changed in the Applicability section so as not to preclude the Planning Coordinator from collecting necessary data.
Response: Thank you for your comment. The majority of industry comments support the SDT proposal not to include a Requirement allowing the Planning Coordinator to request a model review for a unit not specified in the standard Applicability section. Governor response is not consistent from one frequency excursion event to the next for several reasons, such as the operating condition of the plant, ambient temperature, the number of coal pulverizes on line, the pre-contingency MW output of the unit, etc. Therefore, the SDT does not believe it is appropriate to include such a Requirement in MOD-027-1. The Planning Coordinator can still request a model review however the review is not mandatory by standard requirements.		

Organization	Yes or No	Question 2 Comment
Imperial Irrigation District (IID)	Yes	
IRC Standards Review Committee (joint comments)		
Pepco Holdings Inc Affiliates		
NERC System Protection and Control Subcommittee		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	We agree with this proposal as being in line with our overall concern that model verification requirements should be based on cost efficiency and practicality. Facilities outside of the Applicability Section are already judged to be of minimal significance in dynamic impact, and are also typically of vintages and origins whose modeling data and parameters are difficult or impossible to obtain. For facilities of minor dynamic impact in a locality, typical or surrogate model data would serve the simulation purposes the vast majority of times.
Response: Thank you for your comment. The SDT agrees and believes that it has implemented this philosophy in the draft of the standard.		
SPP Reliability Standards Development Team		
SERC Planning Standards Subcommittee		
Idaho Power-Power Production		
Santee Cooper		
PPL Generation	Yes	
Dominion	Yes	

Organization	Yes or No	Question 2 Comment
FirstEnergy	Yes	
SERC Dynamics Review Sub-committee	Yes	
NERC Staff	No	The standard should include a requirement that provides the Planning Coordinator the ability to request a review of any turbine/governor and load control or active power/frequency control system model for a unit not specified in the standard Applicability section. Accurate turbine-governor models can be critical to valid underfrequency load shedding assessments and other studies requiring accurate frequency response. This is particularly important for large units that operate infrequently, but are committed for critical operating conditions such as peak load or other times of capacity deficiency.
Response: Thank you for your comment. The majority of industry comments support the SDT proposal not to include a Requirement allowing the Planning Coordinator to request a model review for a unit not specified in the standard Applicability section. Governor response is not consistent from one frequency excursion event to the next for several reasons, such as the operating condition of the plant, ambient temperature, the number of coal pulverizes on line, the pre-contingency MW output of the unit, etc. Therefore, the SDT does not believe it is appropriate to include such a Requirement in MOD-027-1. The Planning Coordinator can still request a model review however the review is not mandatory by standard requirements. Also, studies in support of the FR SDT effort show that governor response to a frequency excursion is a more critical concern during off peak operations when low capacity factor units are not expected to be committed. The reason for this is that during peak periods, there is inherently more inertia that helps mitigate the severity and duration of the generation – load mismatch.		
Public Service Enterprise Group	Yes	
SERC Generation sub-committee		
ACES Power Members		
Arizona Public Service Company	Yes	
Westar Energy	Yes	

Organization	Yes or No	Question 2 Comment
Southern Company	Yes	
Tennessee Valley Authority GO	Yes	
Luminant Power	Yes	
Lakeland Electric	Yes	
Salt River Project	Yes	
PacifiCorp	Yes	
South Carolina Electric and Gas	Yes	
APS		being intentionally left blank (no answer to be provided)
Associated Electric Cooperative, Inc.	Yes	
Dynegy Inc.	Yes	
New York Independent System Operator		
Tri-State Generation and Transmission, In.	Yes	
Cowlitz County PUD	Yes	
Xcel Energy	Yes	

Organization	Yes or No	Question 2 Comment
Lakeland Electric		
Exelon	Yes	
American Wind Energy Association	Yes	
Tacoma Power	Yes	None
Georgia Transmission Corporation	Yes	
Austin Energy	Yes	
Wisconsin Electric	Yes	
Great River Energy		
BC Hydro	Yes	
Northeast Utilities	No	A Planning Coordinator should be able to request a review of turbine/governor and load control or active power/frequency control system model even though response is not consistent from one frequency excursion event to the next from any unit connected to the power system. If not being listed in the Applicability section is an issue, then the wording should be changed in the Applicability section so as not to preclude the Planning Coordinator from collecting necessary data.
Response: Thank you for your comment. The majority of industry comments support the SDT proposal not to include a Requirement allowing the Planning Coordinator to request a model review for a unit not specified in the standard Applicability section. Governor response is not consistent from one frequency excursion event to the next for several reasons, such as the operating condition of the plant, ambient temperature, the number of coal pulverizes on line, the pre-contingency MW output of the unit, etc. Therefore, the SDT does not believe it is appropriate to include such a Requirement in MOD-027-1. The Planning Coordinator can still request a model review however the review is not mandatory by standard requirements.		

Organization	Yes or No	Question 2 Comment
Constellation Power Generation	Yes	
Consolidated Edison Co. of NY, Inc.	No	A Planning Coordinator should be able to request a review of turbine/governor and load control or active power/frequency control system model even though response is not consistent from one frequency excursion event to the next from any unit connected to the power system. If not being listed in the Applicability section is an issue, then the wording should be changed in the Applicability section so as not to preclude the Planning Coordinator from collecting necessary data.
Response: Thank you for your comment. The majority of industry comments support the SDT proposal not to include a Requirement allowing the Planning Coordinator to request a model review for a unit not specified in the standard Applicability section. Governor response is not consistent from one frequency excursion event to the next for several reasons, such as the operating condition of the plant, ambient temperature, the number of coal pulverizes on line, the pre-contingency MW output of the unit, etc. Therefore, the SDT does not believe it is appropriate to include such a Requirement in MOD-027-1. The Planning Coordinator can still request a model review however the review is not mandatory by standard requirements.		
American Electric Power	Yes	
Ingleside Cogeneration LP	Yes	MOD-027-1 already takes Ingleside Cogeneration LP out of its comfort zone by requiring the ownership and validation of interconnected system performance simulations. This is normally a Transmission Planner or Transmission Operator function, not a Generator Owner. Although we understand the benefit of modeling validations, it is appropriate to begin with only the most critical facilities. If anything, we believe the applicability criteria should be consistent with those generation facilities which have DME installed as required by their Regional Entity. This is a reasonable, in-place means to identify those generators which are important to BES frequency response - and have already the recording equipment needed to validate performance.
Response: Thank you for your comment. It is undesirable to link this standard with the DME standard development. Also, the DME standard applies to fault recorders and PMU equipment. Lower resolution data is adequate for this verification. We agree that if DME is already in place, then it should be simpler to capture the required data for verification. The applicability section requires verification of units larger than the threshold gross nameplate rating size specified for each interconnection and is intended to emphasize the importance of modeling critical units.		
Wisconsin Public Service Corp	Yes	We agree with this proposal as being in line with our overall concern that model verification requirements

Organization	Yes or No	Question 2 Comment
		should be based on cost efficiency and practicality. Facilities outside of the Applicability Section are already judged to be of minimal significance in dynamic impact, and are also typically of vintages and origins whose modeling data and parameters are difficult or impossible to obtain. For facilities of minor dynamic impact in a locality, typical or surrogate model data would serve the simulation purposes the vast majority of times.
Response: Thank you for your comment.		
GE Energy		
ISO New England	No	NERC is largely concerned with the declining frequency response of the Eastern Interconnection and this proposal seems completely at odds with that concern. The Planning Coordinator (or Transmission Planner) should definitely be allowed to request verification of selected governors. In addition to generators that have governor effect overridden by outer control loops (Distributed Control System, DCS) there may be a dead band within the governor. The Transmission Planner must be able to request verification of selected governor models that may fall outside of the standard. The question mentions Planning Coordinator but the standard itself is applicable to the Transmission Planner.
Response: Thank you for your comment. The majority of industry comments support the SDT proposal not to include a Requirement allowing the Planning Coordinator to request a model review for a unit not specified in the standard Applicability section. Governor response is not consistent from one frequency excursion event to the next for several reasons, such as the operating condition of the plant, ambient temperature, the number of coal pulverizes on line, the pre-contingency MW output of the unit, etc. Therefore, the SDT does not believe it is appropriate to include such a Requirement in MOD-027-1. Both the Planning Coordinator and the Transmission Planner can still request a model review however the review is not mandatory by standard requirements. **It is true that the Planning Coordinator is not an applicable FME in the standard since the Planning Coordinator is not assigned responsibility for any of the Requirements.** **The SDT recognizes that modeling improvements are needed in the Eastern Interconnection to correctly represent the frequency response. This standard will require verification of the frequency response model for at least 80% of the interconnection MVA, which will result in improved modeling. The purpose of the standard is to improve the modeling of the frequency response. Other standards are responsible for improving the frequency response.**		

Organization	Yes or No	Question 2 Comment
GenOn Energy	Yes	
Manitoba Hydro	Yes	
Duke Energy	Yes	
Lincoln Electric System		
CPS Energy		
Independent Electricity System Operator	No	We do not agree with this approach. Currently, the applicability threshold of nameplate rating greater that 100MVA is too high. The combined performance of many units smaller than the threshold identified in the applicability section will have a material effect on the system frequency response. Even if the standard leads to the provision of useable model to the Transmission Planner for the applicable generating units, without sufficient good models, it might not be possible to meet the goals of accurately represent generating unit active power response to system frequency variations and predicting system frequency response to contingencies.We repeat the concern we expressed in our comments to MOD-025-2 related to the applicability criteria “connected at the point of interconnection at greater than 100 kV.” This condition will lead to the exclusion of units that are material in dynamic simulations and to which the applicability should extend.Also, we wonder whether the inclusion of Planning Coordinator in the question is a typo or the standard is missing the Planning Coordinator as an applicable entity. Please clarify.

Response: Thank you for your comment. The majority of industry comments support the SDT proposal not to include a Requirement allowing the Planning Coordinator to request a model review for a unit not specified in the standard Applicability section. Governor response is not consistent from one frequency excursion event to the next for several reasons, such as the operating condition of the plant, ambient temperature, the number of coal pulverizes on line, the pre-contingency MW output of the unit, etc. Therefore, the SDT does not believe it is appropriate to include such a Requirement in MOD-027-1. Both the Planning Coordinator and the Transmission Planner can still request a model review however the review is not mandatory by standard requirements.

The SDT recognizes that modeling improvements are needed in the Eastern Interconnection to correctly represent the frequency response. This standard will require verification of the frequency response model for at least 80% of the interconnection MVA, which will result in improved modeling. The purpose

Organization	Yes or No	Question 2 Comment
of the standard is to improve the modeling of the frequency response. Other standards are responsible for improving the frequency response. **It is true that the Planning Coordinator is not an applicable FME in the standard since the Planning Coordinator is not assigned responsibility for any of the Requirements.**		
Gainesville Regional Utilities	Yes	
Ameren	Yes	
Indeck Energy Services	Yes	
Oncor Electric Delivery Company LLC	Yes	
Indiana Municipal Power Agency		
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Chelan County PUD	Yes	

3. The SDT discussed if MOD-027-1 should also include verification of excitation control systems of synchronous condensers. Synchronous condensers are not currently addressed in the NERC Registry Criteria. Synchronous condensers are not mentioned in the Generation Verification SAR. On an MVA capacity basis, the penetration of synchronous condensers in North America is extremely low. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. Therefore, the team decided that a more appropriate strategy would be to include synchronous condensers with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) in a separate SAR.

Do you agree with the proposal to not include the verification of synchronous condensers in MOD-027-1?

Summary Consideration: This question was not intended to be on the Comment Form. The SDT recognizes that synchronous condensers do not contain frequency control elements and regrets the administrative error.

Organization	Yes or No	Question 3 Comment
LG&E and KU Energy		
Northeast Power Coordinating Council	No	Can't generators be operated as synchronous condensers if needed?
Imperial Irrigation District (IID)	Yes	
IRC Standards Review Committee (joint comments)		
Pepco Holdings Inc Affiliates		
NERC System Protection and Control Subcommittee		
Midwest Reliability Organization's NERC Standards	No	It is our opinion that synchronous condensers, when in operation, are intended to regulate local voltages but not for regional frequency control.

Organization	Yes or No	Question 3 Comment
Review Forum (NSRF)		
Response: This question was not intended to be on the Comment Form. The SDT recognizes that synchronous condensers do not contain frequency control elements and regrets the administrative error.		
SPP Reliability Standards Development Team	Yes	We agree as long as the SDT creates the new SAR to address such devices including Synchronous condensers.
Response: This question was not intended to be on the Comment Form. The SDT recognizes that synchronous condensers do not contain frequency control elements and regrets the administrative error.		
SERC Planning Standards Subcommittee		
Idaho Power-Power Production		
Santee Cooper		
PPL Generation	Yes	
Dominion	Yes	
FirstEnergy	Yes	
SERC Dynamics Review Sub-committee	Yes	We agree that it shouldn't be included. However, it appears that there is an error in the question. Synchronous condensers cannot be used to control frequency. Was this a "cut and paste" error from MOD-026?
Response: This question was not intended to be on the Comment Form. The SDT recognizes that synchronous condensers do not contain frequency control elements and regrets the administrative error.		
NERC Staff	Yes	We agree that it is not necessary to validate synchronous condenser models in MOD-027 since synchronous

Organization	Yes or No	Question 3 Comment
		condensers do not provide frequency response. However, the discussion supporting this question refers to verification of excitation control systems. Validation of synchronous condenser excitation control systems should be required in MOD-026.
Response: This question was not intended to be on the Comment Form. The SDT recognizes that synchronous condensers do not contain frequency control elements and regrets the administrative error. The topic of synchronous condensers being included, or not, in the Applicability section of MOD-026 will be addressed in the standards process for MOD-026.		
Public Service Enterprise Group	Yes	
SERC Generation sub-committee		
ACES Power Members	Yes	
Arizona Public Service Company	No	
Westar Energy	Yes	
Southern Company	Yes	
Tennessee Valley Authority GO	Yes	
Luminant Power	Yes	
Lakeland Electric		
Salt River Project	Yes	
PacifiCorp	Yes	
South Carolina Electric and Gas	Yes	

Organization	Yes or No	Question 3 Comment
APS		being intentionally left blank (no answer to be provided)
Associated Electric Cooperative, Inc.	Yes	
Dynegy Inc.	Yes	
New York Independent System Operator		
Tri-State Generation and Transmission, In.	Yes	
Cowlitz County PUD	Yes	
Xcel Energy	Yes	condensers have no effect on system frequency, they are there for voltage support. We agree they should not be in MOD-027-1.
Response: This question was not intended to be on the Comment Form. The SDT recognizes that synchronous condensers do not contain frequency control elements and regrets the administrative error.		
Lakeland Electric		
Exelon		
American Wind Energy Association	Yes	
Tacoma Power		
Georgia Transmission	Yes	

Organization	Yes or No	Question 3 Comment
Corporation		
Austin Energy	Yes	
Wisconsin Electric	Yes	
Great River Energy		
BC Hydro		This standard would not apply to SCs in any case
Response: This question was not intended to be on the Comment Form. The SDT recognizes that synchronous condensers do not contain frequency control elements and regrets the administrative error.		
Northeast Utilities	No	Can't generators be operated as synchronous condensers if needed?
Response: This question was not intended to be on the Comment Form. The SDT recognizes that synchronous condensers do not contain frequency control elements and regrets the administrative error.		
Constellation Power Generation	Yes	
Consolidated Edison Co. of NY, Inc.	No	Can't generators be operated as synchronous condensers if needed?
Response: This question was not intended to be on the Comment Form. The SDT recognizes that synchronous condensers do not contain frequency control elements and regrets the administrative error.		
American Electric Power	Yes	Synchronous condensers respond to changes in voltage and not frequency, and as a result, have no place within the scope of this standard.
Response: This question was not intended to be on the Comment Form. The SDT recognizes that synchronous condensers do not contain frequency control elements and regrets the administrative error.		

Organization	Yes or No	Question 3 Comment
Ingleside Cogeneration LP	Yes	There is already a significant body of work underway defining the extent of the Bulk Electric System. This determination should rest with the project team responsible for that effort.
Wisconsin Public Service Corp	Yes	It is our opinion that synchronous condensers, when in operation, are intended to regulate local voltages but not for regional frequency control.
Response: This question was not intended to be on the Comment Form. The SDT recognizes that synchronous condensers do not contain frequency control elements and regrets the administrative error.		
GE Energy		
ISO New England	Yes	
GenOn Energy		
Manitoba Hydro	Yes	-MOD-027-1 cannot be applicable to units dedicated as synchronous condensers since such units do not have turbine/governor and load control or active power/frequency control functionality installed. For generator units which can be operated as synchronou
Response: This question was not intended to be on the Comment Form. The SDT recognizes that synchronous condensers do not contain frequency control elements and regrets the administrative error.		
Duke Energy	Yes	Not sure why this question is in the CF, other than it was accidently copied from the MOD-26 CF? Synchronous condendors are MVAR devices not MW devices and thus should be covered by MOD-26, not 27, if their dynamic response is signficant to grid reliability. Since they are typically applied in weak spots of the transmission system, it's difficult to believe they would not be critical by their presence.
Response: This question was not intended to be on the Comment Form. The SDT recognizes that synchronous condensers do not contain frequency control elements and regrets the administrative error.		
Lincoln Electric System		

Organization	Yes or No	Question 3 Comment
CPS Energy		
Independent Electricity System Operator	Yes	
Gainesville Regional Utilities	Yes	
Ameren	Yes	The question does not appear to be worded correctly. Draft Standard MOD-027-1 deals with turbine/governor and load control, rather than excitation control systems.
Response: This question was not intended to be on the Comment Form. The SDT recognizes that synchronous condensers do not contain frequency control elements and regrets the administrative error.		
Indeck Energy Services	Yes	
Oncor Electric Delivery Company LLC	No	Oncor does not believe that the inclusion of dynamic reactive devices such as SVC's should be included in MOD-027-1
Response: This question was not intended to be on the Comment Form. The SDT recognizes that synchronous condensers do not contain frequency control elements and regrets the administrative error.		
Indiana Municipal Power Agency		
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Chelan County PUD	Yes	

4. Are you aware of any regional variances that would be required as a result of MOD-027-1? If yes, please identify the regional variance.

Summary Consideration: The vast majority of industry comments did not identify any regional variances. There are minority comments concerned with development of Regional standards. The SDT believes that a Regional standard will have to align with the requirements of a national standard. The SDT also believes that the current Applicability section threshold, which corresponds to greater than 80% of the connected unit MVA per Interconnection, does not constitute a regional variance.

Organization	Yes or No	Question 4 Comment
LG&E and KU Energy		
Northeast Power Coordinating Council	No	
Imperial Irrigation District (IID)	No	
IRC Standards Review Committee (joint comments)		
Pepco Holdings Inc Affiliates		
NERC System Protection and Control Subcommittee		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	No	
SPP Reliability Standards Development Team	No	

Organization	Yes or No	Question 4 Comment
SERC Planning Standards Subcommittee		
Idaho Power-Power Production		
Santee Cooper		
PPL Generation	No	
Dominion	No	
FirstEnergy	No	
SERC Dynamics Review Sub-committee	No	
NERC Staff	No	
Public Service Enterprise Group	No	
SERC Generation sub-committee		
ACES Power Members		
Arizona Public Service Company	No	Verification on units less than 50 MVA is an unnecessary burden and does not add significantly to reliability of BES. Many of these units are not even modeled because of the availability of other units for a given schedule.
Response: Thank you for your comment. The SDT suspects this comment was intended for another standard. However, for the Western Interconnection, Units that are rated 20 MVA only have to be verified if they are part of a plant that is 75 MVA or greater. The SDT believes that 75 MVA plants in the Western Interconnection are significant.		

Organization	Yes or No	Question 4 Comment
Westar Energy	No	
Southern Company	No	
Tennessee Valley Authority GO	Yes	We think it is possible that the unit rating which is critical to the BES may vary from region to region.
Response: Thank you for your comment. The SDT believes that it has accounted for units that are critical to the control of frequency by establishing interconnection specific MVA thresholds corresponding to 80% or greater of the installed MVA generation capacity.		
Luminant Power	No	
Lakeland Electric		
Salt River Project	No	
PacifiCorp	No	
South Carolina Electric and Gas	No	
APS		being intentionally left blank (no answer to be provided)
Associated Electric Cooperative, Inc.	No	
Dynegy Inc.	No	
New York Independent System Operator		
Tri-State Generation and Transmission, In.	No	

Organization	Yes or No	Question 4 Comment
Cowlitz County PUD	No	
Xcel Energy	No	
Lakeland Electric		
Exelon	No	
American Wind Energy Association	No	
Tacoma Power	No	None
Georgia Transmission Corporation	No	
Austin Energy	No	
Wisconsin Electric	No	
Great River Energy		
BC Hydro	No	
Northeast Utilities	No	
Constellation Power Generation	No	
Consolidated Edison Co. of NY, Inc.	No	

Organization	Yes or No	Question 4 Comment
American Electric Power	No	AEP is not aware of the need for any regional variances that might be required as a result of MOD-027-1.
Response: Thank you for your comment.		
Ingleside Cogeneration LP	Yes	In the TRE region, there is already a generator governor/frequency response standard under development. It is not obvious to us that the TRE standard aligns with MOD-027-1.
Response: Thank you for your comment. It should be recognized that a Regional standard also has to comply with the requirements of a National standard.		
Wisconsin Public Service Corp	No	
GE Energy		
ISO New England	No	
GenOn Energy		
Manitoba Hydro	No	
Duke Energy	No	
Lincoln Electric System		
CPS Energy		
Independent Electricity System Operator	No	
Gainesville Regional Utilities	No	
Ameren		

Organization	Yes or No	Question 4 Comment
Indeck Energy Services	Yes	The standard as drafted contains regional standards (ERCOT vs WECC). The ROP doesn't permit members of one region to vote on regional requirements for other regions. Regional standards will be required to implement regional differences.
Response: Thank you for your comment. The SDT believes that it has accounted for units that are critical to the control of frequency by establishing interconnection specific MVA thresholds corresponding to 80% or greater of the installed MVA generation capacity. Even though the MVA threshold is different for each Interconnection, the penetration of connected MVA is essentially the same. It should be recognized that a Regional standard also have to comply with the requirements of a National standard.		
Oncor Electric Delivery Company LLC	Yes	Oncor is in general agreement of the standards however, Oncor believes that the Transmission Planner in the ERCOT Region is not the appropriate receiving entity of test verification data from the Generator Owner. Oncor believes that a regional variance should be given strong consideration such that the Planning Authority would be the receiving entity of all testing data from the Generator Owner. This would align with current ERCOT protocols, operating guide and planning guide at it relates to resource testing and verification.
Response: Thank you for your comment. The SDT believes that it is appropriate to make the Transmission Planner responsible. The Transmission Planner can delegate work as appropriate.		
Indiana Municipal Power Agency		
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Chelan County PUD	No	

5. Are you aware of any conflicts between the proposed MOD-027-1 and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement?

Summary Consideration: The vast majority of industry comments did not identify any conflict between the proposed MOD-027-1 standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement. There are minority comments concerned with the development of Regional standards and also the compatibility of the standard with rules of procedure, LGIAs, etc. The SDT believes that a Regional standard and rules of procedure will have to align with the requirements of a national standard.

Organization	Yes or No	Question 5 Comment
LG&E and KU Energy		
Northeast Power Coordinating Council	No	
Imperial Irrigation District (IID)	No	
IRC Standards Review Committee (joint comments)		
Pepco Holdings Inc Affiliates		
NERC System Protection and Control Subcommittee		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	No	
SPP Reliability Standards Development Team	No	

Organization	Yes or No	Question 5 Comment
SERC Planning Standards Subcommittee		
Idaho Power-Power Production	No	
Santee Cooper		
PPL Generation	No	
Dominion	No	
FirstEnergy	No	
SERC Dynamics Review Sub-committee	No	
NERC Staff	No	
Public Service Enterprise Group	No	
SERC Generation sub-committee		
ACES Power Members		
Arizona Public Service Company	Yes	
Westar Energy	No	
Southern Company	No	
Tennessee Valley Authority GO	No	

Organization	Yes or No	Question 5 Comment
Luminant Power	No	
Lakeland Electric		
Salt River Project	No	
PacifiCorp	No	
South Carolina Electric and Gas	No	
APS		being intentionally left blank (no answer to be provided)
Associated Electric Cooperative, Inc.	No	
Dynegy Inc.	No	
New York Independent System Operator		
Tri-State Generation and Transmission, In.	No	
Cowlitz County PUD	No	
Xcel Energy	No	
Lakeland Electric		
Exelon	Yes	The proposed NERC Standard MOD-027-1 should have a specific exclusion for nuclear generating units which have governors that operate to control steam pressure and which do not respond to grid frequency

Organization	Yes or No	Question 5 Comment
		deviations. This is consistent with the Eastern Interconnection Reliability Assessment Group (ERAG) Multi-Regional Modeling Working Group Procedure Manual version 5, May 6, 2010 which states in Appendix II, Section B Dynamic Modeling Requirements, Paragraph 2b) that "Turbine-governor representation shall be omitted for units that do not regulate frequency such as base load nuclear units, pumped storage units…".
Response: Thank you for your comment. The SDT has added an additional row to Attachment 1 (the Periodicity Table) which specifies units that do not operate in a control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response (such as valves wide open or base loaded) are not required to be verified. The SDT believes this modification will preclude nuclear units from having to perform model verification; and instead show compliance with the Requirement by maintaining documentation explaining the unit's operating mode.		
American Wind Energy Association	No	
Tacoma Power	No	None
Georgia Transmission Corporation	No	
Austin Energy	No	ERCOT has been performing computer modeling based on RARF data provided by GO's.
Response: Thank you for your comment.		
Wisconsin Electric	No	
Great River Energy		
BC Hydro	No	
Northeast Utilities	No	

Organization	Yes or No	Question 5 Comment
Constellation Power Generation	No	
Consolidated Edison Co. of NY, Inc.	No	
American Electric Power	No	AEP is not aware of any conflicts between the proposed MOD-027-1 and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement.
Response: Thank you for your comment.		
Ingleside Cogeneration LP	No	
Wisconsin Public Service Corp	No	
GE Energy	No	
ISO New England	Yes	Requirement R4 is a direct violation of the Large Generator Interconnection portion of the ISO Tariff that requires generators to request permission and provide models prior to making changes to the equipment characteristics. As currently written, this appears to allow generators to submit models after making the changes. Such changes may have been detrimental to system performance and therefore need to be reviewed prior to implementation.
Response: Thank you for your comment. This standard does not preclude the Transmission entity from requiring a model specified by an Interconnection Agreement or other local grid codes. Requirement R4 is a verification requirement therefore verification cannot occur until after frequency control equipment changes are implemented.		
GenOn Energy	No	
Manitoba Hydro	Yes	A number of Canadian Entities have the BES defined within their provincial legislation. This may introduce differences between the elements that are included in the BES (and elements that are therefore applicable to this standard) according to provincial legislation and the NERC definition. As well, since Canadian Entities

Organization	Yes or No	Question 5 Comment
		are not under FERC jurisdiction, the effective date of this standard may differ for Canadian entities and entities under FERC jurisdiction.
Response: Thank you for your comment. The definition of BES and the Applicability in the standard do not have to align. The proposed Effective Date in both the Implementation Plan and in Section 5 of the standard takes into account the differences between US and Canadian entities.		
Duke Energy	No	
Lincoln Electric System		
CPS Energy		
Independent Electricity System Operator	No	
Gainesville Regional Utilities	No	
Ameren		
Indeck Energy Services	Yes	Regional differences violate the ROP.
Response: Thank you for your comment.		
Oncor Electric Delivery Company LLC	Yes	Sections 3.2.1 and 3.2.2 of the ERCOT Operating Guides direct resource entities to communicate operating capabilities directly to the ERCOT ISO. The ERCOT ISO is registered as the Planning Authority. Section 3.3 of the ERCOT Operating Guides direct resource entities to communicate changes to operating capabilities to the ERCOT ISO. Various resource test requirements as listed in Section 8 of the ERCOT Operating Guides indicate data submissions to the ERCOT ISO.
Response: Thank you for your comment. The SDT believes that it is appropriate to make the Transmission Planner responsible. The Transmission Planner can delegate work as appropriate.		

Organization	Yes or No	Question 5 Comment
Indiana Municipal Power Agency		
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Chelan County PUD	No	

6. Do you have any other questions or concerns with the proposed standards that have not been addressed? If yes, please explain.

Summary Consideration: Based in part on industry comments received to this question, the following modifications to the proposed standard have been made by the SDT. (note: some of these issues and listed modifications are addressed by other consideration of comments questions):

1) Corrections of various typos in the body of the standard, the VSLs, and in Attachment 1
2) Extended the time to comply with Requirement 1 from 30 to 90 days
3) Modified Attachment 1 (Periodicity Table) to address units which are always base loaded (by definition a base loaded unit is considered verified).
4) Modified Attachment 1 (Periodicity Table) to clarify establishing the Initial Ten Year Unit Verification Period Start Date
5) Reduced the maximum time allowed between capture of an event and completing model verification from two years to one year.
6) Referenced the NERC GADS document for references to capacity factor in the draft standard.
7) Included partial load rejection as a potential test to obtain a recording of the equipment response to be used in model verification.

Organization	Yes or No	Question 6 Comment
LG&E and KU Energy		
Northeast Power Coordinating Council	Yes	In the Applicability Section, why the differences between the Eastern Interconnection/Quebec and WECC in generating unit and plant sizes specified?

Response: Thank you for your comment. The SDT believes that the proposed applicability thresholds will result in substantial accuracy improvement to the governor models and associated Reliability based limits determined by dynamic simulations, while not unduly mandating costly and time consuming verification efforts. As a basis, the SDT recognized that the governor 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

Organization	Yes or No	Question 6 Comment
Field Test initiated by the Phase III-IV SDT, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the governor models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying governor models, the SDT is proposing to require verification of governor models associated with 80% or greater of the connected MVA per Interconnection. Given the increasing importance of renewable generation plants comprised of several small units, the SDT also proposes requiring verification of these plants and has added language to the Applicability section to capture this intent.		
Imperial Irrigation District (IID)	Yes	IT WOULD BE EFFECTIVE IF SDT WOULD CONSIDER PROVIDING A DETAILED EXAMPLE OF DYNAMIC MODELS, GRAPHS, AND INFORMATION REQUIRED AS PART OF THIS STANDARD.
Response: Thank you for your comment. This standard is not a guideline for developing model parameters. The standard describes what should be done and specifically is not perscriptive. The SDT recognizes expertise is needed to perform model verification for specific types of equipment.		
IRC Standards Review Committee (joint comments)		
Pepco Holdings Inc Affiliates		
NERC System Protection and Control Subcommittee		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	Please consider the following comments:Footnote 2 - Include the explanation that “average capacity factor is the average of all the unit or plant output values compared to the gross nameplate rating value”, since historically some have asked how this factor is defined and calculated”.Requirement R3, bullet 2 - Append wording like, “such as a model is unusable by the Transmission Planner, dubious model type, abnormal model parameter values, and unusual simulation results” to the text, “technical concerns with the verification documentation”. Attachment 1, Row 6 (New or Existing Generator Unit) -Replace “Excitation control system model” with “Turbine/governor and load control or active/frequency control system model”. Comments: We have a number of questions and concerns as follows: o While the Standard uses the word “verified” and “verification” loosely, it is not precisely clear what a GO would have to do to satisfy the verification requirements in R2. Would each of the Time Constants, Forward and/or Feedback Gains, Dead-

Organization	Yes or No	Question 6 Comment
		band Excitation Limits, Saturation Characteristics, etc. to be determined separately each on its own? Or are these parameters taken as a whole so long as their combined effect produces a response characteristic in a simulation that matches the recorded test response during an off-line step-input test? o The response of a unit is dependent on the instantaneous conditions of the external system to which it is connected at the time of the disturbance, in addition to the inherent response characteristics as built. This may result in the modeling parameters derived based on on-line frequency/Load excursion test not being unique. o If a simulation study results in response characteristics that does not match an on-line step input test response, can the GO arbitrarily adjust one or more of the model parametric values to produce a matching response, and send the Transmission Planner these adjusted values as the model data? We have concern about whether this Standard is cost efficient to the industry. The transient stability dynamic modeling for turbine/governor was developed under the assumption of limited bandwidth validity and approximations. The other equipment models in the simulation, e.g. generators, excitation controls, SVCs, HVDC Converters, boiler/burner controls, etc. are all approximations without any correlated degree of accuracies in comparison to each other. On the other hand, the verification efforts are expected to cost quite a bit to GOs, especially for older units whose vendors/manufacturers may not even be in existence any more.

Response: Thank you for your comment. In response to this and other industry comments, the SDT has referenced the capacity factor calculation specified in Appendix F of the GADS Data Reporting Instructions on the NERC website.

Regarding the rest of your comments, the SDT offers the following response:

The SDT constructed text language to ensure the Transmission Planner can address any technical concern with the Generator Owner. Since the Generator Owner is responsible for the model, the Generator Owner can respond that the technical concern raised is unfounded.

The SDT regrets the Attachment 1 typographical error and will correct.

The turbine/governor and load control or active power/frequency control response is a characteristic of the generator equipment, not the external system. The intent is that the Generator Owner should strive to match the predicted response of the complete model with the actual response recorded. Verification of individual parameters should not be the emphasis of the model verification effort.

Organization	Yes or No	Question 6 Comment
It is true that modifying a parameter will alter the predicted response of the model however, an individual parameter should not be assigned an incorrect value for the sake of verifying the model. Ideally, model parameters should be altered to more accurately reflect the physical characteristic represented. However, based on actual experience in the WECC region, the ultimate goal of the verification process is to sufficiently refine model parameters to consistently approximate equipment response to a frequency excursion. The SDT recognizes expertise is required to perform model verification and this is the reason why the model verification periodicity proposed is a 10 year cycle. **Especially considering that the units contained in the Applicability is a subset of the NERC Compliance Registry, the SDT believes that the drafted standard is cost efficient to the industry. As a basis, the SDT recognized that the governor 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 initiated by the Phase III-IV SDT, performing the activities specified in the draft standard is expected to result in improved accuracy of the governor model used in dynamic simulation. Utilizing engineering judgment, based in part on recent entity experience with verifying governor models, the SDT is proposing to require verification of governor models associated with 80% or greater of the connected MVA in each Interconnection. Given the increasing importance of renewable generation plants comprised of several small units, the SDT also proposes requiring verification of these plants and has added language to the Applicability section to capture this intent.**		
SPP Reliability Standards Development Team	Yes	In the VSLS for R2 there is a “no” that needs to be deleted. In VSLS for R2 and R4 there is a footnote referenced on page 2 of the draft standard so it shouldn’t be included here as well.
Response: Thank you for your comment. The SDT believes that it has made the corrections you noted. Please review the current draft of the standard to make sure your concern was addressed.		
SERC Planning Standards Subcommittee		
Idaho Power-Power Production		WECC has an existing model validation policy that is well defined and established. This project documentation does not specifically state that MOD-012 and MOD-013 would be retired. If not, this policy would be redundant with the existing WECC policy.
Response: Thank you for your comment. MOD-027 is a verification requirement. MOD-012 and MOD-013 are data submittal requirements. There are no plans to retire MOD-012 and MOD-013.		
Santee Cooper		

Organization	Yes or No	Question 6 Comment
PPL Generation	Yes	PPL Generation suggests the following changes:1. Increase the capacity factor threshold identified in the Applicability Section from the current 5% to 10%. Otherwise, ambient monitoring may be required for an excessively long period.2. Allow the use of OEM-provided governor models and, if adequate, existing models to satisfy the requirement in R2. OEM models can have equivalent-or-better validity than on-line testing.3. Define what response is expected to be documented for Requirement 2.1.1 (as pertaining to a time-frame of 30 seconds or less, and to sudden frequency dips, not step-increases). Units have an immediate response (e.g. opening the control valves) and a long-term response (e.g. ramping-up the coal feed). Governors (the subject of this standard) deal only with the former category. Ambient monitoring should eventually provide a frequency-dip event to analyze, but the same is not true for opposite-direction events.4. Should the recorded response in Requirement 2.1.1 be the predicted response? It appears that the on-line response and the recorded response are the same thing.5. In Requirement 2.1.1, clarify under what circumstances a lack of response constitutes suitable verification, e.g. experiencing a frequency drop for units running valves-wide-open or CTGs at baseload firing temperature.

Response: Thank you for your comment. Q1: The SDT believes that the 5% capacity factor threshold functions to establish a balance between verifying modeling information for units that play an important role in the reliability of the BES and units that report information which is not verified because they are seldom online and have a relatively diminished reliability role. While it is true that units that have a capacity factor that is marginally greater than 5% could result in a long ambient monitoring period before capturing a response suitable for model verification, the SDT believes that it is better to wait for a suitable event as opposed to requiring a on-line staged test that Generator Owners are not comfortable performing and even argue is not an accurate test. However, in part due to recognizing that relatively low capacity factor units (though greater than 5%), the SDT has added to the standard the ability of the Generator Owner to perform a partial load rejection test. As with the reference change test, the partial load rejection test is an optional strategy. The Generator Owner can choose to wait on an ambient event when the unit is in a mode that is expected to be able to respond to the frequency excursion. Also, as noted in an added footnote in the current draft of the standard, differences between the control mode tested and the final simulation model must be identified, particularly when analyzing load rejection data. Most controls change gains or have a set point runback which takes effect when the breaker opens. Load or set point controls will also not be in effect once the breaker opens. Some method of accounting for these differences must be presented if the final model is not validated from on load data under the normal operating conditions under which the model is expected to apply

Q2: OEM models are not verified and do not capture potential load control or MW setpoint functions.

Q3: Please reference modification of 2.1.1 that clarifies the SDT intent of comparing predicted model response to actual equipment response. The SDT did not specify the timeframe for model verification, instead leaving it to the expert performing model verification to establish. The standard is constructed such that either an over frequency or under frequency event is allowed to be used for model verification. The SDT believes the industry understands that model

Organization	Yes or No	Question 6 Comment
validity during normal stability studies is less than 30 seconds. **Q4 The SDT has modified Requirement 2.1.1 in response to your comment.** **Q5: The SDT has modified Attachment 1 (Periodicity Table) to address units which are always base loaded (by definition a base loaded unit is considered verified).**		
Dominion	Yes	While we understand that a significant portion of the industry supports the 5% capacity factor threshold, we believe that this term is subject to different uses by various entities and parties, particularly biased as to whether one is discussing capacity or energy. We suggest that, for the purpose of this standard, capacity factor be described as defined by NERC GADS.Please elaborate on Requirement 2.1.5. Also, we believe that “Load Control” and “AGC” are the same.R3, the third bullet, we suggest that “did not match the recorded response for three or more transmission system events be changed to “did not approximate the recorded response for three or more transmission system events “We believe there needs to be an exception allowed if a frequency event does not occur in 10 years.What is “staged test” mentioned on Attachment 1? Also Attachment 1 is very confusing and should be rewritten.
Response: Thank you for your comment. The SDT has incorporated your suggestion and updated footnote 2 by referring to the NERC GADS definition (Attachment F). **Load Control and AGC are not the same. Load Control is a plant control also known as MW control. AGC is a Balancing Authority level control.** **The SDT incorporated your recommendation for R3.** **Based on this and others comments, the SDT realized there was an omission in Attachment 1 (the Periodicity Table). Attachment 1 has been revised to make it clear that if a unit is not in a control mode with MW output responsive to a frequency excursion during the 10 year verification cycle, then the entity can continue to wait for this scenario to occur.** **The “staged test” mentioned in Attachment 1 is the “on-line frequency reference change” test referenced in 2.1.1. The SDT has made several corrections and modifications to Attachment 1 in an attempt to make the document easier to understand, including clarifying the Initial Ten Year Unit Verification Period. Also, the SDT has added to the standard the ability of the Generator Owner to perform a partial load rejection test. As with the reference change test, the partial load rejection test is an optional strategy. The Generator Owner can always wait for a frequency excursion to occur when the unit is in a mode that it would be expected to govern. Please review the revised version and provide additional feedback during the next posting.**		
FirstEnergy	Yes	As a result of the 2010 NERC Generator Governor Survey, it became clear that many nuclear units (and I

Organization	Yes or No	Question 6 Comment
		believe all of the BWR units) do not respond to changes grid frequency because their governors are controlling steam pressure. The standard should have a specific exclusion for nuclear generating units which have governors that operate to control steam pressure and which do not respond to grid frequency deviations. This is consistent with the Eastern Interconnection Reliability Assessment Group (ERAG) Multi-Regional Modeling Working Group Procedure Manual version 5, May 6, 2010 which states in Appendix II, Section B Dynamic Modeling Requirements, Paragraph 2b) that "Turbine-governor representation shall be omitted for units that do not regulate frequency such as base load nuclear units, pumped storage units...". For those nuclear units that are able to respond to overfrequency events there is a possibility that a response to a system transient may not be seen during a ten year period. Since responding to an overfrequency event will result in a drop in unit load and a corresponding change in reactivity, the governor control dead band, which is set to minimize the possibility of a spurious reactivity change, could be large enough to ignore an event that meets the frequency excursion threshold (for example a 0.1 Hz dead band would ride through on a 0.07 Hz excursion). Likewise a nuclear unit would not perform a frequency reference change input test with the unit on-line because of the resulting change in reactivity. Would injecting a frequency signal to the EHC during off-line calibration and noting the response be acceptable?
Response: Thank you for your comment. The SDT has added an additional row to Attachment 1 (the Periodicity Table) which specifies units that do not operate in a control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response (such as valves wide open or base loaded) are not required to be verified. The SDT believes this modification will preclude nuclear units from having to perform model verification; and instead show compliance with the Requirement by maintaining documentation explaining the unit's operating mode.		
SERC Dynamics Review Sub-committee	Yes	For Requirement R1, the SERC DRS recommends that the time be changed from 30 calendar days to 90 calendar days. Relative to the time allowed for accomplishing other requirements, there is no benefit for only allowing 30 days for requirement R1. 90 days would allow for more communications between the requesting Generator Owner, the providing Transmission Planner and other entities (such as the software vendor or turbine manufacturer) to coordinate obtaining the necessary items listed in requirement R1. Additionally, 90 days would be consistent with the "more than 90 days" VSL level for this requirement.Relative to R3, bullet three, this covers the situation where predicted response does not match recorded response for three or more events. We suggest this be one or more events because significant events are so rare in the eastern interconnection.Relative to the VSL for R2, the first paragraph in the "Severe column" has confusing words "failed to provide the verified models no more than 90 days late." We

Organization	Yes or No	Question 6 Comment
		recommend changing the words to "provided more than 90 days late".In multiple locations in Attachment 1, 730 days seems to be an excessive amount of time from capturing an event to sending documentation to the TP. We recommend a period of 180 days.In two places in Attachment 1, excitation control system is referred to. Shouldn't this be turbine/ governor control system?
Response: Thank you for your comment. The SDT corrected the discrepancy between R1 and the R1 Lower VSL by changing R1 language to read "within 90 calendar days". **The SDT believes that the 0.05 hertz frequency deviation for the Eastern Interconnection will be exceeded often enough to verify consistent unit equipment response to frequency excursions. As an example, in October 2010, there were 12 Eastern Interconnection frequency excursions that exceeded 0.05 hertz.** **Based on this and other comments, the "Severe" VSL language for R2 has been revised.** **The SDT decided to modify periodicity to indicate that from the date of the last recorded frequency excursion response, the Generator Owner has one year to verify the model. It is expected that the Generator Owner will collect several frequency excursion responses however, the standard only requires model verification within one year of the frequency excursion collected for compliance within the 10 year timeframe.** **The Attachment 1 copy and paste errors with references to "excitation control systems" have been corrected.**		
NERC Staff	Yes	It is not possible to accurately model system frequency response with valid models for only 80% of the installed system capacity. System frequency perturbations are experienced by and responded to by all frequency responsive generators, regardless of interconnection voltage. The standard should be applicable to all units greater than 20 MVA and all plants greater than 75 MVA regardless of interconnection voltage. Per SDT estimates, this will assure accurate modeling for approximately 95% of installed capacity. The interconnection voltage is not relevant to frequency response and should not be a condition for applicability. We also disagree with the exemption for units with <5% capacity factor for the past three years. Some large, less efficient units may only run during peak load conditions giving them lower capacity factors. However, those will also be the units loaded at lower levels, making them the units with head-room to respond, thereby making them critical to frequency response during those conditions. They may be of a lower priority in the implementation plan.The violation risk factors associated with Requirements R1 through R5 should be at least medium. Use of invalid models resulting from violation of these standards can produce erroneous results and adversely affect assumptions of the electrical state or capability of the bulk electric system, or the ability to effectively control or restore the bulk electric system, particularly under emergency, abnormal, or restorative conditions. This can result in operating beyond the true stability limits

Organization	Yes or No	Question 6 Comment
		of the system.The models validated by application of this standard are used in both the long-term planning and the operations planning horizon. The time horizon for Requirements R1 through R5 should include the operations planning horizon.In Requirement R2, part 2.1.1, it appears the comparison should be between recorded response and simulated modeled response rather than between on-line response and recorded response. Further clarification is necessary.In Requirement R4, when the turbine/governor and load control or active power/frequency control system are modified as part of a planned project, the Generator Owner should be required to provide a revised model prior to placing the revised equipment back in service.In Requirement R5, part 5.2, the reference to negligible transients is not measurable. We recommend modifying this to “. . . results in a response that varies less than the numerical stability of the program used for the simulation.”In Requirement R5, part 5.3, the introductory phrase “For an otherwise stable simulation” is not necessary and a potential source of confusion. We recommend deleting this phrase and starting the sentence with “A disturbance simulation results in . . .”The SDT should consider use of the word “verification” versus “validation” and assure that the term used in this standard is consistent with other standards.Validation of models only every 10 years is far too long a period. Models should be calibrated as often as possible, preferably with every significant system frequency disturbance. Experience in the WECC region has shown that validation by observation against system events yields more accurate model performance than relying on a single staged test because the events provide for a wide variety of system conditions for the comparison. The background material suggests that more frequent validation against frequency events is impractical because of the scarcity of events. That is incorrect; there are several frequency events each year in all of the interconnections where frequency deviates beyond the short-term trigger limits set forth by the Resources Subcommittee, which indicate that generators should have exceeded the traditional deadband of Â±36 mHz and responded. The initial completion of validation for all applicable units should be within 5 years, not 10 years. The 10 year time is excessive.Validation or calibration after a measured system event should occur within 6 to 9 months of the event, not 2 years. Experience in the WECC regions shows this to be sufficient and achievable.

Response: Although the standard does not require verification of modeled frequency response for all units/plants smaller than the MVA nameplate rating thresholds listed in the Applicability section, it is expected that provided models are accurate.

The SDT believes that requiring verification of small size MVA units and units with a small (< 5%) capacity factor is not practical and would deplete the industry’s limited verification capability for very little reliability benefit as concluded from the field testing involving 4 regions (WECC, SERC, ERCOT, and the FRCC) initiated by the Phase III-IV SDT and completed July 2007. Units with low capacity factors would seldom be running during significant frequency

Organization	Yes or No	Question 6 Comment
events, and measurements of ambient response data needed for verification would be unavailable because the units were likely not running. With regard to the interconnection voltage identified, the standard does not deviate from the NERC registration requirement. The SDT believes that the 10 year period provides is adequate for both initial verification and re-verification given that the standard also specifies re-verification when equipment changes are made that would affect the units' frequency response. The SDT believes that the lower VRF is appropriate because the model is suppose to be accurate even if the model is not verified. The verification merely provides assurance that the model is accurate. Violation of these requirements are not expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system, which is consistent with the low risk level guideline established. As a comparison, MOD-10 and MOD-12 requirements specify providing a complete set of data for all entity facilities and/or generators. This typically will involve dozens if not hundreds of generators whereas MOD-027 requirements only specify providing data for a single generator unit. Because model verification act ivies typically take months if not years to perform, the time horizon of "Long Term Planning" is appropriate. The SDT thanks you for the comment regarding requirement R2 subpart 2.1.1. The standard has been corrected to require comparison between modeled and measured response. The SDT agrees that models should be revised when equipment is changed. The requirement for providing accurate models is specified by MOD-012. Verification cannot occur until after the revised equipment is in service. There is no known industry practice to take into account the numerical stability of the program. Also, it is left up to the judgment of the expert reviewing the study results to determine if the transients are negligible. Utilizing a stable simulation is necessary to determine if the model will adversely impact the robustness of dynamic modeling to be performed. If an unstable simulation is used as basis, then there is no way to determine additional negative response of the model that is being assessed for useability. The SDT agrees that the term verification is a better term for the requirements of this standard than validation. The standard as currently drafted uses the term verification, not validation. Also, the SDT does recognize that there are several frequency events each year which results in frequency deviations that would exceed traditional deadband settings. It was not the intention of the SDT to suggest otherwise. However, a unit must be both on-line and in a proper operating state so that meaningful MW response recordings can be collected. Regarding the 2 year time frame for validation after a measured system event is recorded, Attachment 1 has been revised to provide only a 1 year period after the event is recorded. This time period provides the Generator Owner time to be notified of the event and assess the impact. The SDT intent was to recognize that it would be a challenge in some Interconnections for a suitable frequency excursion to occur with the unit in a responsive operating state. Based on industry responses to both MOD-027 and MOD-026 postings, the SDT believes that the majority of industry agrees the proposed 10 year periodicity		

Organization	Yes or No	Question 6 Comment
verification cycle is appropriate.		
Public Service Enterprise Group	Yes	Nuclear units are often prohibited by their NRC licenses from having their governors engaged for frequency response. Since the Purpose of the standard is to "accurately represent generator unit real power response to system frequency," nuclear units with the restriction described above will have no response. These units should be explicitly exempted from the standard in the Applicability section.
Response: The SDT has added an additional row to Attachment 1 (the Periodicity Table) which specifies units that do not operate in a control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response (such as valves wide open or base loaded) are not required to be verified. The SDT believes this modification will preclude nuclear units from having to perform model verification; and instead show compliance with the Requirement by maintaining documentation explaining the unit's operating mode.		
SERC Generation sub-committee		
ACES Power Members		
Arizona Public Service Company	No	30 minutes are more than adequate. All components reach steady state temperatures within that time. There is no need to be there more than 30 minutes.
Response: Thank you for your comment. The SDT believes this comment was intended for another standard.		
Westar Energy	No	
Southern Company	Yes	1) Requirement 2.1.1 requires a comparison of the on-line response to the recorded response. The comparison needs to be between the on-line recorded response and the model simulated response. 2) The VSL table for R1 has time frames that don't match the Requirement R1 30 calendar day time frame. 3) The first paragraph of the Severe VSL for R2 needs to be split into two parts to form an additional OR statement which reads: "The GO failed to provide its verified model(s)" OR "The GO provided the verified model(s) more than 90 calendar days late to its TP in accordance with the periodicity timeframe specificed in MOD-027 Attachment 1." 4) The second paragraph of the Severe VSL for R3 is not grammatically correct and does not match the Requirement R3. Please consider changing it to read: "The GO's written response failed to contain one of the following: the technical basis for maintaining the current model, a list of future

Organization	Yes or No	Question 6 Comment
		model changes, or a plan to perform another model verification." 5) For the Lower, Moderate, and Higher VSLs for R5, please consider placing "including a technical description if the model is not useable" within parenthesis to aide in understanding the measure. 6) For the second paragraph of the Severe VSL for R5, please consider rephrasing to read: "The TP provided a written response without including confirmation of all specified model criteria listed in R5, parts 5.1 through 5.3." 7) In Requirement R4, it is unclear how an entity could revise model data without performing a model verification - (the requirement is written to either revise model data or plan to perform model verification) 8) Attachment 1 contains multiple copy/paste errors (from MOD-026) and was difficult to constructively comment on due to these. Those items that need correcting include: 8a) The "Facility" column entries need to better describe the conditions that are being detailed in the "Condition" column. Can some additional words better describe the each row? [for example, the row 2 could have the title 1-existing unit, no sister unit exceptions; row 3 could have the title 2-existing unit, sister unit exception applies, etc.] 8b) The use of "exceptions" in the Draft 1, row 2 is not defined and it is unclear what exceptions may apply. 8c) Can the third AND element of the Condition described in row 2 be written more simply by beginning "While the unit is operating in a frequency responsive mode and is subjected to at least one BES frequency excursion as specified in Criteria 1 above." This change could be used in multiple entries of this table to simply the reading and understanding. 8d) For row 3 (with exceptions row), we suggest eliminating the requirement for the same physical location being true for allow "sisterhood" - an entity is likely to own multiple units at different physical locations which are identical. 8e) Row 5 contains "new excitation control system equipment" - shouldn't this be "new governor/load control equipment"? 8f) Row 7 contains "Excitation control system model" rather than "Gov/Load control model"

Response: Thank you for your comment. 1) The SDT revised Requirement 2.1.1.

2) Based on this and other comments, the SDT lengthened the R1 time frame to 90 days to match the time frame in the associated VSL.

3) The SDT revised Severe VSL language for R2.

4) The SDT agrees the incorrect grammar and has incorporated language similar to what you suggested.

5) The SDT agrees and has incorporated suggested language.

6) The SDT agrees and has incorporated suggested language.

7) In most instances, verification of the model will be required instead of revising model data. An instance where revising model data can suffice is if MW set

Organization	Yes or No	Question 6 Comment
point control is implemented instead of droop control. **8) For 8a) and 8b) NERC has discouraged the use of the term “sister unit” and other folksy terms therefore the SDT believes current language is sufficient. For 8c) The SDT incorporated suggested language. For 8d) The SDT believes that the proxy unit philosophy should be limited to units at the same physical location to improve the likelihood of a legitimate inspection walkdown of equipment and settings is performed by the same individual ensuring that the units are actually “proxy “ units. For 8e and 8f) The SDT regrets the copy and paste errors and has corrected them.**		
Tennessee Valley Authority GO	Yes	It is our opinion that a 20MVA machine is too small to be able to significantly impact a frequency excursion. A technical basis for including units as small as 20MVA in all regions needs to be provided. NERC is focusing on standard requirements that have significant impacts on system reliability, and including units this small seems to be inconsistent with this philosophy. 2)
Response: . Thank you for your comment. For the Eastern Interconnection, 20 MVA rated units only have to be verified if they are part of a plant that is 100 MVA or greater. The SDT believes that 100 MVA plants in the Eastern Interconnection are significant. Also, 20 MVA plants are included in the NERC Registry Criteria.		
Luminant Power	No	
Lakeland Electric		
Salt River Project	No	
PacifiCorp	Yes	Section 4.2 of proposed Standard MOD-027-1 provides that units or plants with an average capacity factor greater than 5% over the last three calendar years, that also meet other characteristics, will be considered “applicable units.” However, the term “capacity factor” is not defined in proposed Standard MOD-027-1. Proposed Standard MOD-026-1, on the other hand, uses the term “Capacity Factor,” suggesting it is a defined term but without an accompanying definition in the NERC Glossary of Terms or otherwise. PacifiCorp believes that the Standards Drafting Teams should make the use of the term “capacity factor” consistent across all proposed standards and define the term as necessary for additional clarity.
Response: Thank you for your comment. The SDT has addressed your suggestion and updated footnote 2 by referring to the NERC GADS definition of capacity factor, in both MOD-026 and MOD-027.		

Organization	Yes or No	Question 6 Comment
South Carolina Electric and Gas	Yes	How are sister units to be handled? Do they all need to be tested individually. Also, are all the units counted individually when calculating the percent of units in the implementation schedule?
Response: Thank you for your comment. Attachment 1 has been revised for clarity regarding the requirement as it pertains to equivalent (sister) units. In determining the percentage of fleet generating units satisfying verification requirements for each implementation schedule effective date specified, all equivalent units are counted as verified if Attachment 1 conditions specified for equivalent units are satisfied.		
APS		being intentionally left blank (no answer to be provided)
Associated Electric Cooperative, Inc.	Yes	1) Item 2.1.1 should be reworded: ".......model verification activities including the on-line RECORDED response compared to the MODEL'S SIMULATED response....."2) It is anticipated that many GO/GOP's may not have industry experience with modeling concepts and model verification techniques. It may be beneficial to provide an appendix for reference that basically describes the anticipated mechanics of how the verification is performed. This may help provide consistency for the verification process.
Response: Thank you for your comment. Requirement R2 subpart 2.1.1 language has been revised. The standard describes what should be done and specifically is not prescriptive. The SDT recognizes expertise is needed to perform model verification for specific types of equipment. Prior to developing the standard SAR, several entities in 4 NERC Regions field tested the concept and demonstrated that verification is practical. Also note that there is an extensive Reference section (Section G) listing several technical papers that address modeling techniques.		
Dynegy Inc.	Yes	1) In R2.1.1 it is not clear if the “recorded” response refers to the model response. Consider rewording this requirement to make clear the meaning of “recorded”. 2.) Attachment 1 seems to give two options for periodicity of verifying the model frequency control functions for existing generators. One option is to record data for a BES frequency excursion during a ten year calendar period. A second option is to record such data after the ten year period if a suitable BES frequency excursion does not occur. Does this mean existing generators can wait indefinitely for a suitable frequency excursion to verify the model response?
Response: Thank you for your comment. The wording in R2 subpart 2.1.1 has been revised. **2) Given the importance of verifying the model based upon actual performance while synchronized to the system, the standard is written to allow ample time for the generator to experience a suitable frequency excursion with the unit on-line and responsive. This means that a GO can wait longer than 10 years for a suitable frequency excursion with the unit on-line and in a mode that it is expected to governor. Also, within the 10 year recurring window, optional**		

Organization	Yes or No	Question 6 Comment
staged tests can be conducted (reference change test or partial load rejection test) in lieu of monitoring for an acceptable ambient event. Since industry has expressed concern, Attachment 1 has been revised to make clear generating units normally operated as a base loaded unit or with valves wide open do not need to be verified. Instead, a statement describing the units operating condition is sufficient for compliance with the requirement. Also, other elements of Attachment 1 have been revised for clarity, including establishing the Initial Ten Year Unit Verification Period.		
New York Independent System Operator		
Tri-State Generation and Transmission, In.	No	
Cowlitz County PUD	No	
Xcel Energy	No	
Lakeland Electric		
Exelon	Yes	Exelon strongly suggests that the SDT coordinate this revised Standard with the Nuclear Regulatory Commission (NRC) to preclude any challenges to the licensing basis of any of the nuclear generating facilities.The proposed NERC Standard MOD-027-1 should have a specific exclusion for nuclear generating units which have governors that operate to control steam pressure and which do not respond to grid frequency deviations. As detailed in a memorandum from Jesus (Nano) Sierrra (FERC) to John Odom (ERAG Management Committee Chair), "Follow-up on the Provision of Primary Frequency Response by Nuclear Units in the ERAG-MMWG Dynamic Models," dated April 27, 2011, most all generating units do not respond to frequency deviations; however, there are some nuclear unit designs that do have limited response to under frequency conditions. It is important to note that even if a nuclear unit' s governor design does have limited response to grid frequency deviations, the nuclear unit is administratively restricted by their respective NRC operating license requirements to 100% thermal power. It is not clear from the proposed Standard MOD-027-1 or the Implementation Plan the SDT intended implementation timeline for the first verification period. That is, when must Requirement R2 be completed for the first 25% of the Generator Owner's applicable units? The second 25%? Etc. It is confusing when

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td></td><td></td><td>considering the wording in Section A.5, "Effective Date:" combined with the wording in Attachment 1, Criteria 2 of the Standard. In addition, the Implementation Plan does not provide any further guidance.Is the intent that the staggered percentage implementation provides the start time for the generating units to complete R2 within a following ten year period? This would allow the applicable units to modify/install recording equipment and then set T=0 to then start the ten year staggered verification period.ORIs the intent to short cycle the initial verification period during implementation based on the percentage of units and then set up a ten year staggered verification period thereafter?</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. The SDT has added an additional row to Attachment 1 (the Periodicity Table) which specifies units that do not operate in a control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response (such as valves wide open or base loaded) are not required to be verified. The SDT believes this modification will preclude nuclear units from having to perform model verification; and instead show compliance with the Requirement by maintaining documentation explaining the unit’s operating mode

Regarding the rest of your comment, Attachment 1 has been revised for clarity and to better reflect the intent of the Implementation Plan. Attachment 1 Criteria 2 has been revised to incorporate the Implementation Plan 9-year transition period schedule including guidance for compliance.</td></tr>
<tr><td>American Wind Energy Association</td><td>No</td><td></td></tr>
<tr><td>Tacoma Power</td><td>No</td><td></td></tr>
<tr><td>Georgia Transmission Corporation</td><td>Yes</td><td>Have software manufacturers agreed to provide their models as described in R1?</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. Yes, the major software manufacturers have agreed to provide their models as described in R1. No later than by the effective date of the standard, software manufacturers’ model information can be obtained from them by entering into the agreements they require.</td></tr>
<tr><td>Austin Energy</td><td>Yes</td><td>Since dynamic data for old units is often not available, the SDT may consider allowing the use of typical or generic modeling parameters for these units.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. If the unit is covered by the proposed Applicability of the draft standard, then the model can still be verified in</td></tr>
</table>

Organization	Yes or No	Question 6 Comment
accordance with the Requirements specified. This is true even if existing dynamic data for an older unit (submitted per the submission Requirements of MOD-012 and MOD-013) is typical or generic data.		
Wisconsin Electric	Yes	It is not clear how this standard would be applied to wind generators. They should perhaps be specifically exempted from these requirements.
Response: Thank you for your comment. Some wind equipment have controls that can respond to a frequency excursion. For wind equipment that does not possess this capability, the SDT has added another row to Attachment 1 (the Periodicity Table) defining requirement exceptions for units that cannot control frequency. For these units compliance with the Requirement is shown by maintaining documentation explaining the unit's operating limitations.		
Great River Energy		
BC Hydro	Yes	The standard apparently favours ambient monitoring as a verification method. While this method has certain advantages over methods traditionally used to verify response of turbine-governors (off-line and on-line step tests), it should be well understood that its implemention is associated with additional costs and difficulties. The question is how would GOs make use of ambient monitoring data to verify the models? GOs are responsible only for equipment models and would not normally have overall system models which are necessary to evaluate the results of ambient monitoring. That puts the focus back on traditional approaches.
Response: Thank you for your comment. Software tools are available for use to record response at the generator terminals (or highside of the GSU) for model verification. The response of the modeled generator to the applied signal can be used to demonstrate that model performance matches measured performance. Overall system model verification is not required to verify the individual generator model.		
Northeast Utilities	Yes	In the Applicability Section, why the differences between the Eastern Interconnection/Quebec and WECC in generating unit and plant sizes specified?
Response: Thank you for your comment. The SDT also believes that the applicability section thresholds specified will result in substantial accuracy improvement to the governor models and associated Reliability based limits determined by dynamic simulations, while not unduly mandating costly and time consuming verification efforts. As a basis, the SDT recognized that the governor 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 initiated by the Phase III-IV SDT, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the governor models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity		

Organization	Yes or No	Question 6 Comment
experiences in verifying governor models, the SDT is proposing to require verification of governor models associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA thresholds which the SDT believes corresponds to 80% of connected MVA or greater for each Interconnection are proposed. Given the increasing importance of renewable generation plants comprised of several small units, the SDT also proposes requiring verification of these plants and has added language to the Applicability section to capture this intent.		
Constellation Power Generation	Yes	CPG is unsure as to what Requirement 2.1.1 is actually requiring. Please explain the difference between an on-line response to a frequency excursion vs. a recorded response. This sub requirement seems to be implying that each GO has the necessary equipment to capture an on line or recorded response. Is it the intent of the drafting team to force GOs to install equipment in order to comply with R2.1.1 along with the conditions found in Attachment 1? CPG would also like clarification on Requirement 2.1.5. Outer loop controls don't affect the governor control (frequency loop). Lastly, CPG would like the SDT to describe how a GO will know that a frequency excursion event occurred on the BES if their facility was unaffected and the facility did not have equipment sensitive enough to measure within .15 Hz.
Response: Thanks for your comment. The language of Requirement R2 subpart 2.1.1 has been revised. The equipment required to capture an on-line frequency response is relatively simple. Experience indicates the MW signal sent to a PI recording systems is adequate if the time resolution is set to two seconds or better. The effects of outer loop controls are important to understand to properly capture the frequency response of the unit. The SDT understands that a list of suitable frequency disturbances will be compiled by other NERC initiatives and made available to industry.		
Consolidated Edison Co. of NY, Inc.	Yes	In the Applicability Section, why the differences between the Eastern Interconnection/Quebec and WECC in generating unit and plant sizes specified?
Response: Thank you for your comment. The SDT also believes that the applicability section thresholds specified will result in substantial accuracy improvement to the governor models and associated Reliability based limits determined by dynamic simulations, while not unduly mandating costly and time consuming verification efforts. As a basis, the SDT recognized that the governor 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 initiated by the Phase III-IV SDT, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the governor models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying governor models, the SDT is proposing to require verification of governor models associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA thresholds which the SDT believes corresponds to 80% of connected MVA or greater for each Interconnection are proposed. Given the increasing importance of renewable generation plants comprised of several small units, the SDT also proposes		

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requiring verification of these plants and has added language to the Applicability section to capture this intent.		
American Electric Power	Yes	Standard models may not be available for wind units and wind facilities (which appear to be within scope of 4.2), particularly aggregate reactive and frequency response controls. As a result, it might be difficult to obtain and provide such information.
Response: Thank you for your comment. Some wind equipment have controls that can respond to a frequency excursion for which non-proprietary models exist. For wind equipment that does not possess this capability, the SDT has added another row to Attachment 1 (the Periodicity Table) defining requirement exceptions for units that cannot control frequency. For these units compliance with the Requirement is shown by maintaining documentation explaining the unit's operating limitations.		
Ingleside Cogeneratio*n* LP	Yes	Like many Generator Owners, Ingleside Cogeneration LP has limited experience with transmission system modeling and scenario planning. Although in general we have a good working relationship with our Transmission Planner, MOD-027-1 may border on exchanging information which either entity may consider to be proprietary. In addition, the extra costs required to deploy recording equipment and to engage external experts to assist with frequency response planning are not budgeted. With this in mind, a priority deployment may be more appropriate - where the most critical facilities in each Region are evaluated first.
Response: Thank you for your comment. The information referenced by this standard needs to be shared between the Generator Owner and Transmission Owner to facilitate essential study work. The implementation plan provides sufficient time for budget planning. Specifically, the proposed phased implementation plan has effective dates of 3, 5, 7 and 9 years after appropriate regulatory approval.		
Wisconsin Public Service Corp	Yes	We have a number of questions and concerns as follows: o While the Standard uses the word "verified" and "verification" loosely, it is not precisely clear what a GO would have to do to satisfy the verification requirements in R2. Would each of the Time Constants, Forward and/or Feedback Gains, Dead-band Excitation Limits, Saturation Characteristics, etc. to be determined separately each on its own? Or are these parameters taken as a whole so long as their combined effect produces a response characteristic in a simulation that matches the recorded test response during an off-line step-input test? o The response of a unit is dependent on the instantaneous conditions of the external system to which it is connected at the time of the disturbance, in addition to the inherent response characteristics as built. This may result in the modeling parameters derived based on on-line frequency/Load excursion test not being unique. o If a simulation study results in response characteristics that does not match an on-line step input test response,

Organization	Yes or No	Question 6 Comment
		can the GO arbitrarily adjust one or more of the model parametric values to produce a matching response, and send the Transmission Planner these adjusted values as the model data? o We have concern about whether this Standard is cost efficient to the industry. The transient stability dynamic modeling for turbine/governor was developed under the assumption of limited bandwidth validity and approximations. The other equipment models in the simulation, e.g. generators, excitation controls, SVCs, HVDC Converters, boiler/burner controls, etc. are all approximations without any correlated degree of accuracies in comparison to each other. On the other hand, the verification efforts are expected to cost quite a bit to GOs, especially for older units whose vendors/manufacturers may not even be in existence any more.

Response: Thank you for your comment. The turbine/governor and load control or active power/frequency control response is a characteristic of the generator equipment, not the external system. The intent is that the Generator Owner should strive to match the predicted response of the complete model with the actual response recorded. Verification of individual parameters should not be the emphasis of the model verification effort. Also note an off-line step test is not allowed to be performed per the current draft language of the standard. The SDT is requiring either a) an on-line step in frequency reference test or b) ambient measurements for a naturally occurring frequency deviation – both of which ensure the effect of MW setpoint control is captured – or c) a partial load rejection test with the requirement that differences between the differences any modes that are disabled as soon as the generator breaker is opened (such as load or set point control).

It is true that modifying a parameter will alter the predicted response of the model however, an individual parameter should not be assigned an incorrect value for the sake of verifying the model. Ideally, model parameters should be altered to more accurately reflect the physical characteristic represented. However, based on actual experience in the WECC region, the ultimate goal of the verification process is to sufficiently refine model parameters to consistently approximate equipment response to a frequency excursion. The SDT recognizes expertise is required to perform model verification and this is the reason why the model verification periodicity proposed is a 10 year cycle.

Especially considering that the units contained in the Applicability is a subset of the NERC Compliance Registry, the SDT believes that the drafted standard is cost efficient to the industry. As a basis, the SDT recognized that the governor 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 initiated by the Phase III-IV SDT, performing the activities specified in the draft standard is expected to result in improved accuracy of the governor model used in dynamic simulation. Utilizing engineering judgment, based in part on recent entity experience with verifying governor models, the SDT is proposing to require verification of governor models associated with 80% or greater of the connected MVA in each Interconnection. Given the increasing importance of renewable generation plants comprised of several small units, the SDT also proposes requiring verification of these plants and has added language to the Applicability section to capture this intent.

Organization	Yes or No	Question 6 Comment
GE Energy	Yes	The second bullet, in part B "Requirements," section R1, page 4: The word "library" should be removed from the phrase "system model library block diagrams," since not all wind manufacturers have standard library models.
Response: Thank you for your comment. The SDT believes that the word "library" is appropriate in this context. User defined models can still be utilized for verification to the extent that the Transmission Planner is willing to accept them.		
ISO New England	Yes	In requirement R2.1.1 what is meant by frequency excursion/reference change?This standard must require that all models provided are non-proprietary, otherwise a major reason (NERC MMG) for model collection will be undermined. This will prevent coordination of studies across regions which may undermine reliability.We are not sure if we have the correct version of draft MOD-027-1. In the "Differences also exist between MOD-026-1 and MOD-027-1" Section of this Comment Form, there are several mentions of Requirement R1 Part 1.x which we are unable to find in the draft standard. For example, Requirement R1 Part 1.2.1 in (5), R1 Part 1.3 in (6), R1 Part 1.4 in (7), and R1 Parts 1.1, 1.3, 1.4 in the "Compliance Elements for MOD-027-1" Section. Also, the referenced MOD-026-1 does not have the parts mentioned in this Comment Form. Is the background provided in this comment form incorrect, or are the posted versions of MOD-026 and MOD-027 out of date?In requirement R5.3: It stipulates as a criterion that a disturbance simulation results in the turbine/governor and Load control or active power/frequency control model exhibiting positive damping. We do not agree with the condition that the simulate must exhibits positive damping. Even with an accurate turbine/governor and Load control or active power/frequency control model, system damping is affected by a many other dynamic performance contributors such as other generators, system topology, power flow levels, voltage levels, excitation system and power system stabilizer settings, etc. In short, having an accurate turbine/governor and Load control or active power/frequency control model does not necessary guarantee or equate to positive damping.
Response: Thank you for your comments. The SDT agrees with your comment that it is important for the model to be non-proprietary. This is why the standard requires each Generator Owner provide data for models that are acceptable to the Transmission Provider. The SDT apologizes for comment form errors discovered. The requirement for positive damping mandates the Generator Owner provide a response if an otherwise acceptable simulation is negatively damped after introducing a new model. This requirement recognizes the fact that equipment must be positively damped during actual operation, so negative damping occurring during simulation would indicate incorrect modeling. Initialization errors and oscillations during steady state conditions would also be an indication of model deficiencies. Each of these tests are components of an established industry practice for assuring model integrity.		

Organization	Yes or No	Question 6 Comment
GenOn Energy		
Manitoba Hydro	Yes	-MH disagrees with the SDT's assumption that the majority of turbine/governor and load control functions will be verified through ambient monitoring. If both turbine/governor and load control functions as well as excitation control functions are to be
Response: Thank you for your comment. Unfortunately part of the comment provided is missing. The SDT believes ambient monitoring is the preferred method for verifying turbine/governor and load control function models. Staged tests do not always capture the effects of load controllers and control modes. However, this standard does permit the optional utilization of stage tests (both on-line reference change and partial load rejections, though the impacts of any wrap around control modes not captured during the staged test have to be considered). The SDT has constructed the standard such that a Generator Owner can wait for a suitable event, even if it takes longer than 10 years when the unit is in a mode that is expected to govern, as opposed to requiring a on-line staged test that a significant number of Generator Owners are not comfortable performing and/or based on the vintage of equipment, do not have the capability of performing.		
Duke Energy	Yes	1) Requirement 2.1.1 requires a comparison of the on-line response to the recorded response. The comparison needs to be between the on-line recorded response and the model simulated response. 2) The VSL table for R1 has time frames that don't match the Requirement R1 30 calendar day time frame. 3) The first paragraph of the Severe VSL for R2 needs to be split into two parts to form an additional OR statement which reads: "The GO failed to provide its verified model(s)" OR "The GO provided the verified model(s) more than 90 calendar days late to its TP in accordance with the periodicity timeframe specificed in MOD-027 Attachment 1." 4) The second paragraph of the Severe VSL for R3 is not grammatically correct and does not match the Requirement R3. Please consider changing it to read: "The GO's written response failed to contain one of the following: the technical basis for maintaining the current model, a list of future model changes, or a plan to perform another model verification." 5) For the Lower, Moderate, and Higher VSLs for R5, please consider placing "including a technical description if the model is not useable" within parenthesis to aide in understanding the measure. 6) For the second paragraph of the Severe VSL for R5, please consider rephrasing to read: "The TP provided a written response without including confirmation of all specified model criteria listed in R5, parts 5.1 through 5.3." 7) Attachment 1 contains multiple copy/paste errors (from MOD-026) and was difficult to constructively comment on due to these. 8) The frequency response of a generation unit is intrinsically connected to the Pmax values used in various system models (old MOD-24). These 2 validation efforts should be connected and the following modeling

Organization	Yes or No	Question 6 Comment
		parameters defined and addressed:Pmax o The continuous operating limit o The ultimate max emergency output. o Should there consider weather conditions (summer or winter, etc.). o PMAX associated with Transient stability - is it the same as for LF o Is this on the order of 105% or 110% or ??% of normal max loading A graphic illustrating this point has been provided to the SDT.
Response: Thank you for your comment. 1) The SDT revised Requirement 2.1.1. **2) Based on this and other comments, the SDT lengthened the R1 time frame to 90 days to match the time frame in the associated VSL.** **3) The SDT revised Severe VSL language for R2.** **4) The SDT agrees the incorrect grammar and has incorporated language similar to what you suggested.** **5) The SDT agrees and has incorporated suggested language.** **6) The SDT agrees and has incorporated suggested language.** **7)) The SDT regrets the copy and paste errors and has corrected them.** **8) The SDT recognizes that to obtain the correct frequency response, the frequency control model needs to limit the modeled response when units are base loaded or operated with valves wide open. The industry is working on resolving this issue and the SDT believes that the proposed MOD-027 provides an appropriate framework. Attachment 1 has been revised to allow owners of units/plants to provide a statement describing control limitation for units that do not provide frequency response as evidence of compliance with the requirement. The SDT did not receive a graphic. However, the SDT can say that loadflow based Pmax is not the same as the dynamic model maximum power.**		
Lincoln Electric System	Yes	Under the Applicability Section, 4.2 Facilities, the “applicable units” are stated to have an average capacity factor greater than 5% over the last three calendar years and that the “majority of industry agreed with the standard MOD-026-1 5% capacity factor threshold” (Background Information: “Standard MOD-027-1” - #3). LES is concerned that the industry builds power flow models for future summer peak conditions, and therefore, LES is not convinced that the capacity factor threshold of less than 5% is a good indication of what units are on-line in these future models. Therefore, the goal for verification of the dynamic models associated with 80% or greater of the connected MVA per Interconnection may not be achieved. LES believes that a check (i.e., survey) of the ERAG MMWG models would be a good indication of whether or not the capacity factor threshold satisfies this objective.

Organization	Yes or No	Question 6 Comment
Response: Thank you for your comment. The SDT believes that the 5% capacity factor threshold functions to establish a balance between verifying modeling information for units that play an important role in the reliability of the BES and units that report information which is not verified because they are seldom online and have a relatively diminished reliability role. While it is true that units that have a capacity factor that is marginally greater than 5% could result in a long ambient monitoring period before capturing a response suitable for model verification, the SDT believes that it is better to wait for a suitable event as opposed to requiring a on-line staged test that Generator Owners are not comfortable performing and even argue is not an accurate test. Finally, by its inherent nature, an expected summer peak load ERAG MMWG case will include many on-line low capacity factor units. However, the SDT recognized that the governor models and model data for all generators in the ERAG MMWG case 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 initiated by the Phase III-IV SDT, performing the activities specified in the draft standard for 80% or greater of units making up the total interconnected MVA is expected to result in an improvement of the accuracy of the governor models used in dynamic simulations.		
CPS Energy		
Independent Electricity System Operator	Yes	We do not agree with some of the requirements.i. R1: Standards should stipulate the “what’s” not the “how’s”. To avoid the perception that the requirement is prescribing the “how”, we suggest simplifying the language of Requirement R1 by replacing “Instruction on how to obtain” with “Instructions for obtaining”.Further, are all three bullets meant to be complied with or are they listed as options? We understand that the general rule for NERC standards is that those items that must be complied with are labeled as parts (e.g. 1.1, 1.2, etc.) while those that are options or examples that do not need to be complied with are placed in bullets. Please verify this with the Director of Standards Process.ii. R2.1: The phrase “models acceptable to its Transmission Planner” begs the question on what is deemed acceptable and what if the GO disagrees with the TP’s determination. To address the two issues, we suggest adding a requirement for the TP to specify the models (or change the second bullet in R1 to achieve this), and change the wording in R2.1 to “in accordance with the models specified by the TP (or referencing the requirement part that contains the specification). Another possibility would be to remove this phrase altogether since the Transmission Planner would in any case have to declare the model “useable” pursuant to Requirement R5.iii. R5.3: It stipulates as a criterion that a disturbance simulation results in the turbine/governor and Load control or active power/frequency control model exhibiting positive damping. We do not agree with the condition that the simulate must exhibits positive damping. Even with an accurate turbine/governor and Load control or active power/frequency control model, system damping is affected by many other dynamic performance contributors such as other generators, system topology, power flow levels, voltage levels,

Organization	Yes or No	Question 6 Comment
		excitation system and power system stabilizer settings, etc. In short, having an accurate turbine/governor and Load control or active power/frequency control model does not necessary guarantee or equate to positive damping. Similar arguments may also apply to R5.1 and R5.2, i.e., that having an accurate model does not necessarily mean that the modeling data can be initialized without errors, and a no-disturbance simulation always results in negligible transients. We suggest the SDT to revise the determination criteria, based solely on the models specified by the TP, the data provided by the GO meeting the specified model requirements, and the tracking of actual performance, where applicable.iv. We decide not to comment on the Measures and other compliance elements at this time in view of the comments, above.
Response: Thank you for your comments. Requirement 1 does describe the "what" and avoids being prescriptive. Upon request, the Transmission Planner provides requested information to the Generator Operator. Items that the Generator Owner can request from the Transmission Planner are stated in requirement 1 (refer to the bulleted items). The Transmission Planner is only required to provide the items if requested to do so and as such the standard language and format is correct. **Since the Transmission Planner is the user of the model, submitted models must be acceptable to the transmission planner to be useful. The first bullet under requirement R1 does require the Transmission Planner to provide instructions on how to obtain the list of acceptable models.** **The requirement for positive damping mandates the Generator Owner provide a response if an otherwise acceptable simulation is negatively damped after introducing a new model. This requirement recognizes the fact that equipment must be positively damped during actual operation, so negative damping occurring during simulation would indicate incorrect modeling. Initialization errors and oscillations during steady state conditions would also be an indication of model deficiencies. Each of these tests are an established industry practice for assuring model integrity.**		
Gainesville Regional Utilities	No	
Ameren	Yes	(1) There may be different usage of the term 'point of interconnection" in the industry. We suggest the SDT to consider proposing a formal definition of this term. (2) R4 of the Draft references footnote 5. It appears this footnote is overly broad and requires editing to precisely identify equipment systems that can truly impact system reliability. This footnote should be edited so it becomes either a new Requirement or a new set of sub-requirements. No other systems should be included.
Response: Thank you for your comment. 1) The standard has been revised for clarity regarding the meaning for the "point of interconnection." The SDT believes a formal definition is not needed since the point of interconnection is described in the standard.		

Organization	Yes or No	Question 6 Comment
2) In the development of Footnote 5, the SDT strove to cover all reasonable examples that might result in the alteration of equipment response. However, the requirement leaves the responsibility for determining what alters equipment response to the Generator Owner.		
Indeck Energy Services	Yes	This standard imposes significant costs on generators and requires them to, in many cases unless they are also a transmission company, to hire consultants to conduct the verification. There is no evidence that unverified model data for units smaller than the level of the NERC Reportable Disturbance for the control area will have any impact on BPS reliability.
Response: Thank you for your comment. This standard has been vetted including SAR development and field testing. Industry believes that this standard is needed. The STD recognizes there are costs associated with compliance and has proposed a standard applicability limited to the most critical units/plant listed in the compliance registry criteria.		
Oncor Electric Delivery Company LLC	No	
Indiana Municipal Power Agency		
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Chelan County PUD	No	

END OF REPORT