Consideration of Comments

Project 2007-09 Generator Verification

MOD-026-1 and PRC-024-1

The Generator Verification Drafting Team thanks all commenters who submitted comments on the proposed revisions to MOD-026-1 and PRC-024-1. These standards were posted for a 30-day public comment period from February 29, 2012 through March 29, 2012. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 53 sets of comments, including comments from approximately 127 different people from approximately 88 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

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

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 and Director of Standards, Mark Lauby, at 404-446-2560 or at Mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

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	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.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
7.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
8.	Chantel Haswell	FPL Group, Inc.	NPCC	5
9.	David Kiguel	Hydro One Networks, Inc.	NPCC	1
10.	Michael R. Lombardi	Northeast Utilities	NPCC	1

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

11. Randy MacDonald	New York State Reliability Council, LLC	NPCC	9
12. Bruce Metruck	New York Independent System Operator	NPCC	6
13. Lee Pedowicz	Hydro-Quebec TransEnergie	NPCC	10
14. Robert Pellegrini	Consolidated Edison Co. of New York, Inc.	NPCC	1
15. Wayne Sipperly	Northeast Power Coordinating Council	NPCC	5
16. Si-Truc Phan	Dominion Resources Services, Inc.	NPCC	1
17. David Ramkalawan	Consolidated Edison Co. of New York, Inc.	NPCC	5
18. Brian Robinson	FPL Group, Inc.	NPCC	8
19. Saurabh Saksena	Hydro One Networks, Inc.	NPCC	1
20. Michael Schiavone	Northeast Utilities	NPCC	1
21. Tina Teng	New York State Reliability Council, LLC	NPCC	2
22. Donald Weaver	New York Independent System Operator	NPCC	2
23. Ben Wu	Hydro-Quebec TransEnergie	NPCC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2. Group	Don Jones	Texas Reliability Entity										X

Additional Member	Additional Organization	Region	Segment Selection
1. Curtis Crews	Texas Reliability Entity	ERCOT	10
2. David Penney	Texas Reliability Entity	ERCOT	10

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

Additional Member	Additional Organization	Region	Segment Selection
1. Jonathan Hayes	Southwest Power Pool	SPP	2
2. Robert Rhodes	Southwest Power Pool	SPP	2
3. Valerie Pinamonti	AEP	SPP	1, 3, 5
4. Michelle Corely	CLECO	SPP	1, 3, 5
5. Mahmood Safi	OPPD	MRO	1, 3, 5

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

Additional Member	Additional Organization	Region	Segment Selection
1. James Jones	Arizona Electric Power Cooperative	WECC	4, 5
2. James Jones	Southwest Transmission Cooperative, Inc.	WECC	1
3. Lindsay Shepard	Sunflower Electric Power Corporation	SPP	1

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

	Additional Member	Additional Organization	Region	Segment Selection
4.	Scott Brame	North Carolina Electric Membership Corporation	RFC	1, 3, 4, 5
5.	Mike Brytowski	Great River Energy	MRO	1, 3, 5

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

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

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

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Tom Flynn	Puget Sound Energy	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Denise Lietz	Puget Sound Energy	WECC	1
2.	Erin Apperson	Puget Sound Energy	WECC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Mike Garton	Dominion	X		X		X	X				

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

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	WILL SMITH	MRO NSRF	X	X	X	X	X	X				X

	Additional Member	Additional Organization	Region	Segment Selection
1.	MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6
2.	CHUCK LAWRENCE	ATC	MRO	1
3.	TOM WEBB	WPS	MRO	3, 4, 5, 6
4.	JODI JENSON	WAPA	MRO	1, 6

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

	Additional Member	Additional Organization	Region	Segment Selection
5.	KEN GOLDSMITH	ALTW	MRO	4
6.	ALICE IRELAND	XCEL (NSP)	MRO	1, 3, 5, 6
7.	DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6
8.	ERIC RUSKAMP	LES	MRO	1, 3, 5
9.	JOE DEPOORTER	MGE	MRO	3, 4, 5, 6
10.	SCOTT NICKELS	RPU	MRO	4
11.	TERRY HARBOUR	MEC	MRO	5, 6, 1, 3
12.	MARIE KNOX	MISO	MRO	2
13.	LEE KITTELSON	OTP	MRO	1, 3, 4, 5
14.	SCOTT BOS	MPW	MRO	1, 3, 5, 6
15.	TONY EDDLEMAN	NPPD	MRO	1, 3, 5
16.	MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6
17.	THERESA ALLARD	MPC	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Jesus Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jose Landeros	IID	WECC	1, 3, 4, 5, 6
2.	Cathy Bretz	IID	WECC	1, 3, 4, 5, 6
3.	Christopher Reyes	IID	WECC	1, 3, 4, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Annette M. Bannon	PPL Electric Utilities and PPL Supply NERC Registered Organizations	X				X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
2.	Annette Bannon	PPL Generation, LLC on Behalf of its NERC Registered	RFC	5
4.	Mark Heimbach	PPL EnergyPlus, LLC	MRO	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Steve Rueckert	Western Electricity Coordinating Council										X

No additional members listed.

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Chuck	Matthews	WECC	1
2.	Rebecca	Berdahl	WECC	

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Individual	David Youngblood	Luminant Power					X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
15.	Individual	Jim Eckelkamp	Progress Energy	X		X		X	X				
16.	Individual	David Thompson	Tennessee Valley Authority GO/GOP	X		X		X	X				
17.	Individual	Janet Smith, Supervisor Regulatory Compliance	Arizona Public Service Company	X		X		X	X				
18.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
19.	Individual	Antonio Grayson	Southern Company	X		X		X					
20.	Individual	Frederick R Plett	Massachusetts Attorney General								X		
21.	Individual	Dan Roethemeyer	Dynegy					X					
22.	Individual	Matthew Pacobit	AECI					X					
23.	Individual	John Seelke	PSEG	X		X		X	X				
24.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
25.	Individual	Dale Fredricksen	We Energies			X	X	X					
26.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
27.	Individual	Michael Falvo	Independent Electricity System Operator		X								
28.	Individual	Kathleen Goodman	ISO New England Inc		X								
29.	Individual	Keira Kazmerski	Xcel Energy	X		X		X	X				
30.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
31.	Individual	Anthony Jablonski	ReliabilityFirst										X
32.	Individual	Thad Ness	American Electric Power	X		X		X	X				
33.	Individual	Michelle R D'Antuono	Ingleside Cogeneration LP					X					
34.	Individual	Brad Jones	Luminant Energy						X				
35.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
36.	Individual	Richard Vine	California Independent System Operator		X								
37.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
38.	Individual	Daniel J Hansen	GenOn Energy					X					
39.	Individual	Patrick Brown	Essential Power, LLC					X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
40.	Individual	Kirit Shah	Ameren	X		X		X	X				
41.	Individual	Larry Raczkowski	FirstEnergy Corp	X		X	X	X	X				
42.	Individual	Mark B Thompson	Alberta Electric System Operator		X								
43.	Individual	Jeanie Doty	Austin Energy	X		X	X	X					
44.	Individual	Randall McCamish	City of Vero Beach	X		X							
45.	Individual	Christine Hasha	ERCOT		X								
46.	Individual	Ed Davis	Entergy Services	X		X		X	X				
47.	Individual	Patrick Farrell	Southern California Edison Company	X		X		X	X				
48.	Individual	Ken Wofford	Georgia Transmission Corporation	X									
49.	Individual	Mauricio Guardado	Los Angeles Department of Water and Power	X		X		X	X				
50.	Individual	Russell A. Noble	Cowltiz PUD			X	X	X					
51.	Individual	Michael Goggin	American Wind Energy Association								X		
52.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
53.	Individual	John Bee	Exelon Corp.	X		X		X					

MOD-026 Overall Summary Consideration: The GVSDT received valuable feedback from stakeholders regarding improvements to the standard. Many of the suggested edits were incorporated into the revised standard.

The vast majority of the industry commenters agreed with the concept of specifying that validation is not required for an excitation control system or plant volt/var control that does not include an active closed loop voltage regulation function. The GVSDT received comments regarding other aspects of the standard. Several Industry commenters indicated that it was not clear if the table was associated with Attachment 1 or not. In response, the SDT has re-formatted Attachment 1 to make it clear that the table is a part of Attachment 1. Also, some commenters were concerned that Table 1 inferred that plants with complex reactive coordination controllers may be unduly exempted from being applicable. The SDT clarified that for plants that include devices that provide dynamic voltage regulation (such as a STATCOM, DVAR or SVC, commonly found in Renewable Plants) these devices should be included in the model and should be validated. The intent of this language was to exempt only those units or plants that do not contain any closed loop voltage regulation function. The SDT added some clarifying verbiage to row 6 Table 1 that ultimately references Footnote 1 in the standard.

Most of industry commented that they agreed with the guidance provided by the SDT on the periodicity aspects of Attachment 1. Unfortunately, many commenters did not correlate the guidance on the periodicity aspects of Attachment 1 to the examples "above" in the Background section of the Comment Form. Please see the Summary Consideration section for Question 5 as there were several comments regarding the periodicity examples.

The majority of the industry commenters agreed with specifying the capacity factor calculation in Appendix F of the GADS Data Reporting Instructions. Also, many of the commenters pointed out that neither the net or gross calculation was specified in the standard and suggested the SDT use the "net" calculation. As such, the SDT has revised the draft standard to reference the net capacity factor calculation in Appendix F of the GADS Data Reporting Instructions. Finally, the SDT moved the details of the capacity factor exemption concept form a footnote in the Applicability section to a row (Row 7) in the Periodicity Table. The team thought that would be appropriate as the Periodicity Table already included the "equivalent" unit concept (Row 4)

The following modifications to the draft standard were incorporated as a result of industry comments:

1. **A significant number of industry commenters opposed the use of the term "bulk power system" in the Applicability section. The SDT did not mean to convey a modification in the breadth of units which would be covered by the standard as "bulk power system" is a term used in the Compliance Registry. But based on the concerns expressed by industry, the SDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System".**

2. The SDT has refined verbiage and the format in the standard applicability and Requirement R2, Part 2.1 to clarify the use of individual and aggregate models for plants.

3. The SDT removed the footnote regarding standby units as industry comments suggested that it did not provide additional clarity to the Applicability.

4. The SDT replaced "Planning Coordinator" with "Transmission Planner" in the standard. The Functional Model for the Transmission Planner is more in line with the task described in the standard. This revision was made in Section 4.2.4 under Applicability, in Requirement R5, and in Attachment 1.

5. The SDT revised the Applicability section 4.2.4 to make it clear that it applied to technically justified units that meet the NERC Registry criteria. It is emphasized that "technical justification" is defined by demonstrating that the simulated unit or plant response does not match the measured unit or plant response.

6. Requirement R2, Part 2.2 has been re-worded and merged into Part 2.1. The new verbiage makes it clear that the entity performing the model verification has flexibility regarding if the model should be represented by individual unit or plant aggregate models or any combination therein as dictated by the specific situation. This merger also results in appropriate mapping to the VSLs.

7. The SDT has refined section 4.2.1, 4.2.2, and 4.2.3 of the Facilities section under Applicability.

8. The SDT has re-formatted the Periodicity Table (Attachment 1) to make it clearer that the table is included.

9. Revised the Periodicity Table (Attachment 1) extensively for clarity, including removing specificity regarding when the voltage excursion used for model verification had to be captured. This resulted in a modification of the required times for re-verifying the model for exception (Requirements R3 and R4) type activities.

10. The SDT made corrections to VSL verbiage (less than or equal to with respect to days late) and replaced Planning Coordinator with Transmission Planner.

11. In Requirement R5, in describing checking the actual equipment to determine if updated model data could be obtained, the expression "walk down" was replaced by "on-site review" of the equipment

12. The term "inertia" in sub part 2.1.3. was modified to "total rotational inertia" as some industry commenters expressed concern that reference to "inertia" only would lead to submittal of an inertia constant reflective only of the generator, as opposed to all of the mass attached to the shaft.

13. In Requirement R2, Part2.1.1, the specific reference to point of interconnection has been removed. The location where the unit's response is measured is left to the model verification entity.

14. **The second bullet in Requirement R1 has been modified to be the same style and sentence structure used in the first bullet of R1.**
15. **The SDT has removed the term "generating plant / Facility" and replaced it with "individual generating plant consisting of multiple generation units that are directly connected at a common BES bus" at the top level of the Facilities section (A4.2).**
16. **The SDT modified the phrase "generator excitation control system and plant volt/var control functions" to "generator excitation control system or plant volt/var control functions" to recognize that the use of the phrase "or" is technically correct the vast majority of the time.**

1. **The GVSDT has added an additional condition to Attachment 1 (the Periodicity Table) specifying that validation is not required for an excitation control system or plant volt/var control that does not include an active closed loop voltage regulation function. This condition exempts wind and solar plants that do not have the capability to regulate plant voltage or respond to grid voltage fluctuations other than switching capacitor and reactor banks in and out of service. Do you agree with this concept? If not, please explain in the comment area below.**

Summary Consideration: The vast majority of the industry commenters agreed with the concept of specifying that validation is not required for an excitation control system or plant volt/var control that does not include an active closed loop voltage regulation function.

Several Industry commenters indicated that it was not clear if the table was associated with Attachment 1 or not. In response, the SDT has re-formatted Attachment 1 to make it clear that the table is a part of Attachment 1.

Also, some commenters were concerned that Table 1 inferred that plants with complex reactive coordination controllers may be unduly exempted from being applicable. The SDT clarified that for plants that include devices that provide dynamic voltage regulation (such as a STATCOM, DVAR or SVC, commonly found in Renewable Plants), these devices should be included in the model and should be validated. The intent of this language was to exempt only those units or plants that did not contain any closed loop voltage regulation function. The SDT added some clarifying verbiage to the appropriate row in Table 1 (referencing back to Footnote 1).

Organization	Yes or No	Question 1 Comment
Independent Electricity System Operator	Negative	Requirement R6: The criteria for deeming the model data provided by the GO acceptable may not be achievable. The difficulty to meet this requirement may not be due to inaccuracy or errors in the verification process, but simply due to the poor design of the devices to be verified. The requirement can deem a GO non-compliant despite its goodwill and effort to provide the most accurate verification data. **Requirement R6 represents established industry practice for assuring model usability. The Transmission Planner is required to notify the**

Organization	Yes or No	Question 1 Comment
		Generator Owner within 90 calendar days of receiving the verified model so that the Generator Owner knows if the model is useable or not. However, if the Generator Owner is notified that a model is not useable, per Requirement 3, the GO is only responsible for providing a written response. Thus, if the Generator Owner responds with a written response as detailed in Requirement R3, the GO will be in compliance. The revised Attachment 1 is confusing, in 2 aspects: a. It is not clear whether or not the 3 by 12 table part is part of Attachment 1 and whose content is part of the periodicity requirements that must be complied with. **The table is included in Attachment 1. The format has been modified to emphasize that the table is included in Attachment 1.** b. Question 2 in the Comment Form suggests that guidance is provided on the periodicity aspects of Attachment 1. It is not clear whether the content in the 3x12 table is meant to be guidance. If so, it needs to be clearly stated so that it does not need to be complied with. If the content is not guidance, then it is not clear where and what is the guidance that the SDT is referring to. **The "guidance" that was referred in question 2 of the Comment Form was referencing the graphical examples in the MOD-026 Background Information portion of the Comment Form (specifically reference Periodicity Example 1, Periodicity Example 2, and Periodicity Example 3).**
Response: Thank you for your comment. Please see responses above.		
Northeast Power Coordinating Council	No	While some plants may not have excitation systems, they can have complex reactive coordination controllers whose settings and functions should be tested and verified.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comment. The intent was not to give an exemption to any unit or plant that has a closed loop voltage regulation function. If a plant has a device that provides dynamic voltage regulation (such as a STATCOM, DVAR or SVC, commonly found in Renewable Plants), these devices should be included in the model and should be validated. The intent of this language was to exempt only those units or plants that did not contain any closed loop voltage regulation function (and therefore nothing to model or validate in the scope of this standard). To clarify this point, a reference to Footnote 1 in Row 6 of the Periodicity Table has been made for clarification of what constitutes a closed loop function.		
Massachusetts Attorney General	No	a particular unit may not pose much problem to a system but an aggregation may. One would think that over a threshold # of MW that active close loop regulation functions should be present.
Response: Thank you for your comment. The scope of the draft standard is to ensure that excitation control system and plant volt/var control function models and the model parameters used in dynamic simulations accurately represent the generator excitation control system and plant volt/var control function behavior when assessing Bulk Electric System (BES) reliability. Requirements specifying thresholds requiring active closed loop regulation functions are outside the scope of the standard as stated in the SAR.		
Manitoba Hydro	No	Manitoba Hydro agrees with the concept for manually switched capacitor banks but disagrees for automatic capacitor banks. A model should be required for automatic capacitor banks.
Response: Thank you for your comment. The intent was not to give an exemption to any unit or plant that has a closed loop voltage regulation function. If a plant has a device that provides dynamic voltage regulation (such as a STATCOM, DVAR or SVC, and perhaps automatically controlled capacitors commonly found in Renewable Plants), these devices should be included in the model and should be validated. If the automatically controlled (mechanically switched) capacitor bank is in whole or a part of		

Organization	Yes or No	Question 1 Comment
the primary dynamic volt/var response of the plant, it should be modeled and validated. Both PSS/e and PSLF have standard library models to represent automatically switched capacitor banks (SWSHNT in PSS/e and MSC1 in PSLF). Ultimately, the local interconnection requirements should be used to determine if the automatically controlled capacitor banks are a primary means for dynamic volt/var regulation within any particular application. Based on review of a plant's application requirements, the testing /validation entity should determine if the automatic capacitor bank should be validated.		
ISO New England Inc	No	While some plants may not have excitation systems, per se, they can have complex reactive coordination controllers, whose settings and functions should be tested and verified.
Response: Thank you for your comment. The intent was not to give an exemption to any unit or plant that has a closed loop voltage regulation function. If a plant has a device that provides dynamic voltage regulation (such as a STATCOM, DVAR or SVC, commonly found in Renewable Plants), these devices should be included in the model and should be validated. The intent of this language was to exempt only those units or plants that do not contain any closed loop voltage regulation function (and therefore nothing to model or validate in the scope of this standard). **To clarify this point, a reference to Footnote 1 in Row 6 of the Periodicity Table has been made for clarification of what constitutes a closed loop function.**		
Southern Company	Yes	Yes we agree with this concept. It is not practical, and there is no benefit to reliability, to require validation for units which do not include an active closed-loop voltage regulator function.
Response: The SDT thanks you for your comment.		
We Energies	Yes	Add more explicit detail to the Table to indicate that the exemption may apply to some wind farms, solar resources, etc.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comment. To clarify this point, a reference to footnote 1 in Row 6 of the Periodicity Table has been made for clarification of what constitutes a closed loop function to determine if, in part, an exemption is allowable for a particular plant.		
Ingleside Cogeneration LP	Yes	We agree that there is no useful purpose served by requiring a GO to validate voltage performance on those generators where an active voltage regulator is not used. The modeling of passive capacitor and reactor banks has been established for many years and does not likely need any improvement.
Response: The SDT thanks you for your comment.		
Los Angeles Department of Water and Power	Yes	LADWP agrees with this concept since no feedback signal is available (in an open loop control) to regulate against for Setpoint (Reference) control.
Response: The SDT thanks you for your comment.		
Texas Reliability Entity	Yes	
Southwest Power Pool Standards Development Team	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Puget Sound Energy	Yes	
MRO NSRF	Yes	

Organization	Yes or No	Question 1 Comment
Imperial Irrigation District (IID)	Yes	
PPL Electric Utilities and PPL Supply NERC Registered Organizations	Yes	
Luminant Power	Yes	
Tennessee Valley Authority GO/GOP	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Dynegy	Yes	
AECI	Yes	
PSEG	Yes	
Independent Electricity System Operator	Yes	
Xcel Energy	Yes	
American Transmission Company, LLC	Yes	
American Electric Power	Yes	
Luminant Energy	Yes	

Organization	Yes or No	Question 1 Comment
Duke Energy	Yes	
South Carolina Electric and Gas	Yes	
GenOn Energy	Yes	
Essential Power, LLC	Yes	
Ameren	Yes	
FirstEnergy Corp	Yes	
Austin Energy	Yes	
Southern California Edison Company	Yes	
Georgia Transmission Corporation	Yes	
Cowltiz PUD	Yes	
American Wind Energy Association	Yes	
Exelon Corp	Yes	
Pepco Holdings Inc. & Affiliates		No comment
Indiana Municipal Power Agency		no comment

2. The GVSDT has provided guidance on the periodicity aspects of Attachment 1 (see above). Do you agree? If not, please explain in the comment area below.

Summary Consideration: Most of industry commented that they agreed with the guidance provided by the SDT on the periodicity aspects of Attachment 1.

Several Industry commenters indicated that it was not clear if the table was associated with Attachment 1 or not. In response, the SDT has re-formatted Attachment 1 to make it clear that the table is a part of Attachment 1. Unfortunately, many commenters did not correlate the guidance on the periodicity aspects of Attachment 1 to the examples "above" in the Background section of the Comment Form. Please see the Summary Consideration section for Question 5 as there were several comments regarding the periodicity examples.

Organization	Yes or No	Question 2 Comment
Independent Electricity System Operator	Negative	Requirement R6: The criteria for deeming the model data provided by the GO acceptable may not be achievable. The difficulty to meet this requirement may not be due to inaccuracy or errors in the verification process, but simply due to the poor design of the devices to be verified. The requirement can deem a GO non-compliant despite its goodwill and effort to provide the most accurate verification data. The revised Attachment 1 is confusing, in 2 aspects: **Requirement R6 is intended for the Transmission Planner. If the Transmission Planner deems that the model is not useable, then the Generator Owner has to reply to the Transmission Planner's written comments. The Generator Owner's obligation is to respond to the Transmission Planners written comments, therefore, the only way the Generator Owner could be found non-compliant is if he did not respond at all.** a. It is not clear whether or not the 3 by 12 table part is part of Attachment 1 and whose content is part of the periodicity requirements that must be complied with.

Organization	Yes or No	Question 2 Comment
		b. Question 2 in the Comment Form suggests that guidance is provided on the periodicity aspects of Attachment 1. It is not clear whether the content in the 3x12 table is meant to be guidance. If so, it needs to be clearly stated so that it does not need to be complied with. If the content is not guidance, then it is not clear where and what is the guidance that the SDT is referring to. **The intent is that Attachment 1 includes the table. Based on your comment, Attachment 1 has been re-formatted in such a way that it is clear that the table is included in Attachment 1. The "guidance" that was referred in question 2 of the Comment Form was referencing the graphical examples in the MOD-026 Background Information portion of the Comment Form (specifically reference Periodicity Example 1, Periodicity Example 2, and Periodicity Example 3). Given that Requirement R2 requires model verification per the periodicity specified in Attachment 1, and Attachment 1 contains the table, then the table does dictate required model verification periodicity.**
Response: Thank you for your comment. Please see responses above.		
Independent Electricity System Operator	No	Attachment 1 is confusing, in 2 aspects: a. Attachment 1 starts off with a heading and a blue-shaded page in which the verification periodicity requirements are clearly stated. It is not clear whether or not the 3 by 12 table that follows is a part of Attachment 1 and whose content is part of the periodicity requirements that must be complied with. b. This question (Q2) suggests that guidance is provided on the periodicity aspects of Attachment 1. Is the content in the 3x12 table meant to be guidance? If so, it should be clearly stated so that it does not need to be complied with. If not, where and what is the guidance that the SDT refers to?

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment. The intent is that Attachment 1 includes the table. Based on your comment, Attachment 1 has been re-formatted in such a way that it is clear that the table is included in Attachment 1. The "guidance" that was referred in question 2 of the Comment Form was referencing the graphical examples in the MOD-026 Background Information portion of the Comment Form (specifically reference Periodicity Example 1, Periodicity Example 2, and Periodicity Example 3). Given that Requirement R2 requires model verification per the periodicity specified in Attachment 1, and Attachment 1 contains the table, then the table does dictate required model verification periodicity.		
American Electric Power	No	The tiered approach of MOD-026 Attachment 1 are both unorganized and more complex than necessary, and is confusing as a result. The same approach could be communicated in a more succinct format. In addition, there is content within the attachment that is not mentioned anywhere else in the standard, such as the initial verification of new units and dealing with equivalent units at the same physical location.
Response: Thank you for your comment. The intent of the Periodicity Table is to specify periodicity details which would not be considered reliability related requirements. However, the SDT is always open to specific suggestions regarding the formatting of the standard and supporting attachments.		
Ameren	No	The comments and guidance of the GVSDT are greatly appreciated. However, we have a concern/question, how would the periodic verification/testing requirements for MOD-026 would align with other such requirements in place for MOD-024, MOD-025 and with reporting requirements of MOD-012 and MOD-013? We would like the GVSDT to consider a well-coordinated periodic verification and reporting needs for all such requirements to provide the GO flexibility to schedule their tasks to meet these requirements without undue burden to take facility out of service at different times.
Response: Thank you for your comment. MOD-024 and MOD-025 have now been combined. The verification of steady state MW and MVAR capabilities would be accomplished by test which is distinctly different than the activities required for verification of excitation control systems. Also, the verification of steady state MW and MVAR capabilities would be accomplished without		

Organization	Yes or No	Question 2 Comment
taking the unit out of service. Personnel involved in steady state MW and MVAR capabilities will almost certainly be different than personnel involved in the verification of excitation control systems. Also, the verification of excitation control systems per the current draft of MOD-026 will almost always be ten years, whereas the periodicity of steady state MW and MVAR capabilities per the current draft of MOD-025 is only five years. MOD-012 and MOD-013 are simply data submittal standards as opposed to data verification standards.		
Austin Energy	No	Per R1. the TP should provide periodicity.
Response: Thank you for your comment. The SDT believes that a national standard for dynamic model verification has to include periodicity to ensure that excitation control system models used in studies to set BES limits are of sufficient accuracy.		
Exelon Corp.	No	The SDT needs to clarify and state that generating units will be able to use testing and verification data developed prior to the standard being approved and going into effect. Please consider adding text specifically stating this to the Standard itself similar to MOD-026 Attachment 1 that provides a “Consideration for Early Compliance” provision. Refer to MOD-026-1 draft revision 2 Section 6, “Consideration for Early Compliance.
Response: Thank you for your comment. The SDT re-formatted Attachment 1 in part to emphasize activities that would result in an entity being able to take credit for model verification prior to the effective data, as long as that activity either met the requirements of the standard or was performed compliant with the applicable regional policies, guidelines or criteria existing at the time of model verification (reference Note 2 at the end of the table).		
ACES Power Marketing Standards Collaborators	Yes	The examples included in the Unofficial Comment Form are helpful in understanding the periodicity requirements associated with verifying the excitatation and volt/VAr control systems model and should be moved into an attachment in the standard. The standard is not as clear as the examples and the periodicities could be misinterpreted in the future without examples.
Response: Thank you for your comment. The examples provided were for clarification, and the SDT does not believe that all		

Organization	Yes or No	Question 2 Comment
possible scenarios are considered. The SDT does not believe the examples are appropriate for inclusion in the standard itself.		
Southern Company	Yes	A periodicity of ten years between model verifications when there are no special circumstances is appropriate. What is the basis for a ten year re-verification for units where no changes to the excitation system have occurred? A ten year verification basis for an non-modified digital excitation system does not seem to be justified.
Response: Thank you for your comment. The SDT believes that the 10 year periodicity is appropriate and has received industry support for this concept, specifically as a result of the first posting. Digital excitation systems settings can be modified, and there are other components in the closed loop system that can degrade with heat and stress over time (SCRs, any discrete electronic component, etc).		
PSEG	Yes	The examples in the unofficial comment form should be incorporated into an attachment to the standard for ease of reference.
Response: Thank you for your comment. The examples provided were for clarification, and the SDT does not believe that all possible scenarios are considered. The SDT does not believe the examples are appropriate for inclusion in the standard itself.		
Manitoba Hydro	Yes	The implementation plans/effective dates for the standards MOD-025 , MOD-026, MOD-027, and PRC-019 in Project 2007-09 should be the same to reduce unnecessary outages and to maximize the productivity of site visits. Manitoba Hydro suggests that the implementation plan for MOD-026 be applied to MOD-025, MOD-027 and PRC-019.
Response: Thank you for your comment. MOD-024 and MOD-025 have now been combined. The verification of steady state MW and MVAR capabilities would be accomplished by test which is distinctly different than the activities required for verification of excitation control systems. Also, the verification of steady state MW and MVAR capabilities would be accomplished without taking the unit out of service. Personnel involved in steady state MW and MVAR capabilities will almost certainly be different than personnel involved in the verification of excitation control systems. Also, the verification of excitation control systems per the current draft of MOD-026 will almost always be ten years, whereas the periodicity of steady state MW and MVAR capabilities		

Organization	Yes or No	Question 2 Comment
per the current draft of MOD-025 is only five years. Also, the effective and implementation dates for the current drafts of MOD-026 and MOD-027 (dynamic model verification standards) are effectively the same.		
Ingleside Cogeneration LP	Yes	We support the effort by all project teams to clearly define the implementation and subsequent periodic evaluation time frames - as well as those that may result from changes in the facility or models. Unfortunately, any assumptions or gaps in the timelines will force NERC's Compliance team to address them through a CAN, which do not allow for sufficient vetting by the industry. In the case of MOD-026-1, we believe that the proposed intervals are sufficient to perform the voltage performance model validations; however they are initiated.
Response: The SDT thanks you for your comment.		
GenOn Energy	Yes	In Attachment 1, the title "Consideration for Early Compliance" should be changed to "Compliance for Prior Verification"
Response: Thank you for your comment. The SDT re-formatted Attachment 1 in part to emphasize activities that would result in an entity being able to take credit for model verification prior to the effective data, as long as that activity either met the requirements of the standard or was performed compliant with the applicable regional policies, guidelines or criteria existing at the time of model verification.		
Los Angeles Department of Water and Power	Yes	LADWP agrees with the guidance.
Northeast Power Coordinating Council	Yes	
Texas Reliability Entity	Yes	

Organization	Yes or No	Question 2 Comment
Southwest Power Pool Standards Development Team	Yes	
Puget Sound Energy	Yes	
MRO NSRF	Yes	
Imperial Irrigation District (IID)	Yes	
PPL Electric Utilities and PPL Supply NERC Registered Organizations	Yes	
Luminant Power	Yes	
Tennessee Valley Authority GO/GOP	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Massachusetts Attorney General	Yes	
Dynegy	Yes	
AECI	Yes	
ISO New England Inc	Yes	

Organization	Yes or No	Question 2 Comment
Xcel Energy	Yes	
American Transmission Company, LLC	Yes	
Luminant Energy	Yes	
Duke Energy	Yes	
South Carolina Electric and Gas	Yes	
Essential Power, LLC	Yes	
FirstEnergy Corp	Yes	
Southern California Edison Company	Yes	
Georgia Transmission Corporation	Yes	
Cowltiz PUD	Yes	
American Wind Energy Association	Yes	
Pepco Holdings Inc. & Affiliates		No comment
Indiana Municipal Power		no comment

Organization	Yes or No	Question 2 Comment
Agency		

3. **Based on the latest round of industry feedback, the GVSDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly leading to model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. Though not a change from the previous posting, the SDT emphasizes for clarity that only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) or units that are already registered (for reasons such as being required to by their RRO) are subject to Requirement R5. Do you agree with the revisions to applicability and to Requirement R5? If not, please explain in the comment area below.**

Summary Consideration:

1) **The SDT has refined section 4.2.4 of the Facilities section under Applicability to clarify that any technically justified unit that meet NERC registry criteria is potentially in the scope of the standard**

   Additionally, though not specifically related to the SDT's question, the following modifications were made to the standard based on industry responses in this question:

2) **A significant number of industry commenters opposed the use of the term "bulk power system" in the Applicability section. The SDT did not mean to convey a modification in the breadth of units which would be covered by the standard as "bulk power system" is a term used in the Compliance Registry. But based on the concerns expressed by industry, the SDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System".**
3) **The SDT has refined verbiage and the format in the standard applicability and Requirement R2, Part 2.1 to clarify the use of individual and aggregate models for plants.**
4) **The SDT removed the footnote regarding standby units as industry comments suggested that it did not provide additional clarity to the Applicability.**
5) **The SDT replaced "Planning Coordinator" with "Transmission Planner" in the standard. The Functional Model for the Transmission Planner is more in line with the task described in the standard.**

Organization	Yes or No	Question 3 Comment
Beaches Energy Services, City	Negative	The applicability refers to the "bulk power system", e.g., "4.2.1.1 Individual generating unit greater than 100 MVA (gross nameplate rating) directly connected to

Organization	Yes or No	Question 3 Comment
of Green Cove Springs		the bulk power system". The term "bulk-power system" should not be used in the standards as it is ambiguous and should be replaced with "Bulk Electric System" We do not understand how the Applicability of 4.2.1.2 means. We suggest making the language clearer. **We appreciate your thoughtful comments. Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.** R2.1.1 should only apply if a system disturbance actually happens and should not require a staged test. A staged test could threaten the reliability of the BES more than inaccuracy of an excitation system model. **A staged test to obtain data to verify excitation control system models does not involve an actual BES voltage excursion. A staged test typically involves injecting a step change signal into the unit's voltage regulator – which makes the voltage regulator "think" that a voltage excursion has occurred. Usually a laptop PC can be used to record the resulting staged testing data. There has been ample experience in industry with safely and effectively using a staged test.** R4 should specifically exclude temporary changes, e.g., generator AVR settings are often changed when the unit is started or shut-down, if the AVR is planned out of service, etc., we believe the intent of the standard is only to communicate more permanent changes and not temporary changes. **Changes in operating mode (auto/manual, PSS on/off, etc.) do not trigger the need to provide a revised model or re-verification as described in Requirement R4. The following sentence has been added to Footnote 5 to clarify the intent: "Changes in settings that occur due to changes in operating mode do not apply to Requirement R4".** R5 is ambiguous. What is technically justified? Who gets to decide what is technically qualified? **"Technical justification" is defined by the TP as demonstrating that the simulated**

Organization	Yes or No	Question 3 Comment
		unit or plant response does not match the measured unit or plant response.
Response: The GVSDT thanks you for your comment. Please see responses above.		
PacifiCorp	Negative	1. PacifiCorp does not support the addition of the term "bulk power system" to Section 4.2.2.1 of the "Applicability" section. The term is ambiguous and, in this context, fails to provide the clarity afforded by either the previous language ("at greater than or equal to 100 kV") or the defined term of "Bulk Electric System." PacifiCorp suggests maintaining the existing applicability language, including the "directly connected" qualifier so that the sentence reads as follows: "Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected to the point of interconnection at greater than or equal to 100 kV." **We appreciate your thoughtful comments. Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.** 2. PacifiCorp believes that the second bullet under Section 4.2.2.2 of the "Applicability" section introduces confusion for registered entities. If we correctly understand the intent of the GVSDT, then please consider the following language to replace the two existing bullets: o "Each individual generating unit greater than 20 MVA (gross nameplate rating), plus an aggregate model for the other generating units of less than 20 MVA at the plant/Facility; and o Where there are no individual generating units greater than 20 MVA in a plant/Facility with total generation greater than 75 MVA (gross aggregate rating), an aggregate model for the generating units of less than 20 MVA." **The SDT has refined section 4.2.2 of the Facilities section under Applicability and Part 2.1 to clarify the use of individual and aggregate models for plants.** 3. PacifiCorp agrees that the addition of sub-Requirement 2.2 is a good clarification, but believe that the language could be further clarified to remove unnecessary confusion by amending the sub-Requirement as follows: "For generating

Organization	Yes or No	Question 3 Comment
		plants/Facilities with total generation greater than the thresholds established in the Applicability section of this standard that are comprised of units that have gross nameplate rating of less than 20 MVA, each Generator Owner shall perform its verification using plant aggregate model(s) that include the information required by Requirement sub-parts 2.1.1 through 2.1.6." **The SDT moved the language that was in Part 2.2 to Part 2.1, and modified the language to make it clear that the use of individual or aggregate models for units less than 20 MVA (gross nameplate capability) is left to the discretion of the entity performing the model verification.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Public Utility District No. 1 of Lewis County	Negative	As a generator owner of a small plant we do not have the experience or expertise in modeling therefore all model and explanation of model would come from a testing and consultant firm. There is a high cost for a small plant to obtain this test data. Standard should only apply to 100MVA generators as in the Eastern and Quebec interchange. **The individual unit and aggregate plant ratings used in the applicability section were carefully derived for each Interconnection to capture validation of approximately 80% of the total installed base in that region. The selection of these applicability requirements intend to strike the most reasonable balance between managing the costs to perform tests and validation vs. ultimately assuring that the reliability of the Bulk System is not compromised due to poor models.** If we run the model testing and the Transmission Planner does not like the modeling, then we have to run the model testing again? More cost and no benefit to us or the system. **There is no requirement or measurement in the standard where the planning authority accepts or denies quality of the match between the model and field tests. The SDT strongly believes that the judgment of an "adequate model" is best**

Organization	Yes or No	Question 3 Comment
		left to the Generator Owner and their testing and validation entity. In the SDT's experience, the adequacy of the validated models is not questioned by planning authorities. However, per Requirement R6, questions regarding the usability of these models (i.e. initialization, numerical stability, etc) may exist and would need to be addressed. The Transmission Planner should select plant and units that are critical to system operation, not one size fits all as stated in the standard. **The SDT was unable to identify a methodology that is consistently applicable to all regions and interconnections regarding "critical system components". Therefore, MVA thresholds are the only common means to be used as a proxy for defining "critical system components".**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Northeast Power Coordinating Council	No	Footnote 4 in the Applicability Section implies comparing simulated unit or plant responses to dynamic system events. Verifying the model only after an event as is called for in footnote 4 is completely counter to increasing system reliability. Analyzing an event and determining that a particular generating unit model is inaccurate will prove difficult in practice. The Applicability Section needs further revision because by requiring only generators above 100 MVA with unit capacity factors above 5 % to test excludes an unacceptably large amount of installed generation. For example, about 30% of the installed generation in New England would not therefore, require model validation. This is an excessively large portion of the generation that is being exempted. Additionally, the low capacity factor units will likely be running during the periods when the system is being most stressed and reliable operation is being most challenged. If the objective of the Standard is to develop the right models for dynamic simulations, models must include high and low capacity factor units, transient and

Organization	Yes or No	Question 3 Comment
		long term models, etc. for all network conditions. A model for the generators and associated equipment is supplied in accordance with MOD-012. The accuracy of such models may be limited and a higher percentage of generator validation is required. **As discussed in the Comment Form with the first posting of the draft MOD-026 standard, the SDT considered the extent of the facilities to be verified and how to reflect this in the "applicability" of this proposed standard. As a basis, the SDT recognized that the excitation system models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the Field Test, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the exciter models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA thresholds corresponding to 80% of connected MVA or greater for each Interconnection are proposed. It is recognized that certain boundaries within an interconnection, such as BA boundaries, may have more or less than 80% of the connected MVA.** **The SDT further believes that a minimum unit interconnection of >100 kV, consistent with the Compliance Registry Guidelines, is appropriate. Finally, the SDT believes that the standard should apply to units with a capacity factor such that they are on-line 400 hours or greater a year. The SDT believes that these three applicability thresholds will result in substantial accuracy improvement to the excitation models and associated Reliability based limits determined by dynamic simulations, while not unduly mandating costly and time consuming verification efforts. Footnote 4 (footnote 2 in the current draft) is intended to allow the Transmission Planner to request model information, possibly leading to model verification, for units which fall within the NERC Compliance Registry but are not of the base Applicability of this**

Organization	Yes or No	Question 3 Comment
		proposed standard. **Also, the SDT does recognize that Regional variances can be considered if a Region desires to include additional unit MVA in this standard.** Footnote 4 should be changed to allow verification of generator models not required under the Applicability Section to be at the discretion of the Transmission Planner. In some areas of the system, generator models have a considerable impact on dynamic performance and model accuracy is critical. Requirement R5 authorizes the PC to apply MOD-026 to any generator not included in the Applicability section of MOD-026. This would authorize the PC to apply the standard to non-BES generation, which is not appropriate. What is meant by a "technically justified request" from the PC? R5 refers to the Planning coordinator, yet the Planning Coordinator is not listed in the Applicability Section of MOD-026. MOD-026 deviates from the NERC Functional Model Version 5 in that MOD-026 R5 has the Generator Owner communicating with the Planning Coordinator. T The NERC Functional Model stipulates that the Transmission Planner communicates with the GO/GOP. The PC then collects the data from the TPs in its area, and from adjacent PCs. The Standard should be consistent with the NERC Functional Model. **Thank you for your comment. The SDT has refined section 4.2.4 of the Facilities section under Applicability to clarify that any technically justified unit that meets NERC registry criteria is potentially in the scope of the standard – notably excluding units and plants that do not meet the thresholds of the registry criteria. The SDT also has replaced references to the Planning Coordinator with the Transmission Planner, in large part due to the reasons you have stated.** **Also, the SDT does recognize that Regional variances can be considered if a Region desires to include units based on other criteria to this standard.**

Organization	Yes or No	Question 3 Comment
Response: The GVSDT thanks you for your comment. Please see responses above.		
ACES Power Marketing Standards Collaborators	No	We appreciate the drafting team explaining their intent that only those units that meet the Compliance Registry Criteria are included. However, the language in the standard does not communicate this and the Statement of Compliance Registry Criteria has some ambiguous criteria that makes it unclear if a generator is applicable which is further discussed below. First, applicability section 4.2.4 of the standard discusses “any registered technically justified unit”. Units are not registered. Entities (i.e. companies) are registered. A Generation Owner certainly becomes registered by the application of the Compliance Registry Criteria to its generating fleet but there is no publicly available list to which the applicable entities can refer to identify if a generating unit met the Compliance Registry Criteria. Thus, how would a Planning Coordinator know they could make a request? **The SDT has refined section 4.2.4 of the standard applicability to clarify that any technically justified unit that meets NERC registry criteria is potentially in the scope of the standard.** Second, the Compliance Registry Criteria includes units smaller than the 20 MVA unit threshold and 75 MVA plant threshold referenced by the drafting team. Blackstart Resources are included in the Compliance Registry Criteria and there is a statement that any generator that is material to the reliability of the Bulk Power System can be included. Blackstart Resources are usually very small and most likely do not meet the 5% capacity factor requirement established in other areas of the applicability section. **The SDT did not intend to treat black start units differently from any other units.** We are guessing the drafting team did not intend to include these Blackstart units or any others units that don’t meet the 20 MVA unit threshold and 75 MVA plant threshold established in Criteria III(c).1 and III(c).2 with the Appendix 5B - Statement of Compliance Registry Criteria.

Organization	Yes or No	Question 3 Comment
		For clarity, the drafting team should modify applicability section 4.2.4 accordingly to eliminate units that are not intended to be included. Third, we disagree with the statement in the Background Information section of the comment form that the applicability section would have to explicitly identify units below the Compliance Registry Criteria. **The SDT has refined section 4.2.4 of the standard applicability to clarify that any technically justified unit that meets NERC registry criteria is potentially in the scope of the standard.** Because the standards applicability is not specifically limited to the Bulk Electric System, the statement in Requirement R5 that "any/plant not included in the Applicability" means that any unit that is considered part of the Bulk Power System could be requested by the Planning Coordinator. NERC enforces standards to the Bulk Power System which could include units below the Compliance Registry Criteria. They have made this clear in response to comments on CAN-0016 that the standards are enforced to the Bulk Power System. **The SDT has refined section 4.2.4 of the Facilities section under Applicability to clarify that any technically justified unit that meet NERC registry criteria is potentially in the scope of the standard. Also the SDT has replaced the term "BPS" with the defined term "BES".** They stated clearly "According to Section 39 of the Energy Policy Act of 2005, NERC defines the Interconnected Power Grid as the Bulk Power System. Unless otherwise restricted by a standard, it is applicable to the BPS." While the Bulk Power System has never been clearly defined, we know that it is broader than the Bulk Electric System and could certainly include units below the Compliance Registry Criteria. One solution to more fully implement the expressed intent of the drafting team would be to limit the applicability section to the Bulk Electric System. **Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.**

Organization	Yes or No	Question 3 Comment
		Another would be to modify "any unit/plant not included in the Applicability" in Requirement R5 to "any unit/plant on the Bulk Electric System and not included in the Applicability". While the question posed by the drafting team here indicates that their intent was for the Planning Coordinator's technical justification to indicate that the actual unit response does not match the simulated response, there is nothing in the standard or requirement that indicates this intent. In fact, it only states the request from the Planning Coordinator must be technically justified. **The SDT has refined section 4.2.4 of the Facilities section under Applicability to clarify that any technically justified unit that meets NERC registry criteria is potentially in the scope of the standard.** We suggest the drafting team modify Requirement R5 to make it clearer the actual system response does not match simulated response. **The clarification for technical justification from Transmission Planner that actual unit response does not match simulated response is included in the referenced Footnote 2.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
MRO NSRF	No	It is suggested the following modification to R5 will more clearly mirror the SDT intent as depicted in the question: "...any unit/plant meeting the Registry Criteria not included in the Applicability that includes one of the following..."
Response: Thanks you for your comment. The SDT has refined section 4.2.4 of the Facilities section under Applicability to clarify that any technically justified unit that meets NERC registry criteria is potentially in the scope of the standard.		

Organization	Yes or No	Question 3 Comment
PPL Electric Utilities and PPL Supply NERC Registered Organizations	No	The term "standby" in footnote 2 on p.2 bears definition. Is 5% capacity factor the criterion to be used in establishing standby status? If so, it would be best to make this standard entirely unit-based, eliminating all references to plants.
Response: Thank you for your comment. The SDT decided to remove Footnote 2 as the term did not provide clarity to industry as was hoped.		
Massachusetts Attorney General	No	I am concerned about units that may be individually less than 20 MVA but collectively could be much larger - wind farms.
Response: Thank you for your comment. The applicability and Part 2.1 was refined to clarify the use of individual and aggregate models for plants. With this change in the applicability, the SDT believes that this has been addressed, since the objective has always been to validate models for units or plants larger than a certain threshold (different for each interconnection).		
AECI	No	I believe that the threshold of 20 MVA is too low. I would recommend a threshold of a (> 75 MVA)
Response: Thank you for your comment. The applicability was refined to clarify the use of individual and aggregate models for plants. With this change in the applicability, the SDT believes that this has been addressed, since the objective has always been to validate models for units or plants larger than a certain threshold. In other words, validation for small units are only required when these units are part of a plant with total output above the threshold for the given interconnection (75 MVA for ERCOT and WECC and 100 MVA for the Eastern Interconnection).		
Consolidated Edison Co. of NY, Inc.	No	Requirement 5: o R5 authorizes the PC to apply MOD-026 to any generator not included in the Applicability section of MOD-026. This would authorize the PC to apply the standard to non-BES generation, which is not appropriate.

Organization	Yes or No	Question 3 Comment
		The SDT has refined section 4.2.4 of the Facilities section under Applicability to clarify that any technically justified unit that meet NERC registry criteria is potentially in the scope of the standard. o It is not clear what constitutes a "technically justified request" from the PC. **The technical justification for a request is described in footnote 2 of the current draft of the standard.** o Refers to Planning Coordinator, but PC is not listed in Applicability section of MOD-026. **The reference to Planning Coordinator has been changed to Transmission Planner to be consistent with the Applicability section of the standard and to conform to NERC functional model.** o Further, under NERC Functional Model Version 5 the Transmission Planner communicates with the GO/GOP. The PC collects data from the TP's in its area and from adjacent PC's. See NERC Functional Model Version 5. The standards should conform to the NERC Functional Model. **The reference to Planning Coordinator has been changed to Transmission Planner to be consistent with the Applicability section of the standard and to conform to NERC functional model.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
We Energies	No	We strongly oppose this Requirement as unnecessary to the reliability of the BES. Requirement R5 should be removed from the draft Standard. Either the standard is applicable to a generating unit, or it is not. A generating unit that is not covered in the Applicability section should be exempt from the requirements of this standard unless the standard is revised under the approved

Organization	Yes or No	Question 3 Comment
		standards development process. The SDT's assurances to the contrary are not sufficient. This requirement will allow the possibility of sweeping more generators into the requirements than is necessary.
Response: Thanks you for your comment. The SDT has refined section 4.2.4 of the Facilities section under Applicability to clarify that any technically justified unit that meet NERC registry criteria is potentially in the scope of the standard. Also the SDT has replaced the term "BPS" with the defined term "BES".		
ISO New England Inc	No	No, Footnote 4 in the Applicability Section implies comparing simulated unit or plant response to a dynamic system event. This is not acceptable, verifying the model only after an event as called for is completely counter to increasing system reliability. In addition, analyzing an event and determining that a particular generating unit model is inaccurate will prove difficult in practice. **The majority of industry supports an applicability which results in the required verification of 80% of the Interconnected MVA. The associated Requirement R5 does allow the TP a means to pursue additional model information if the model's predicted response does not match the actual equipment response. The SDT believes this is a reasonable way to allow the TP to pursue model information in the rare instances where there is an issue with a model that is not part of the base applicability.** We feel the applicability section needs further revision, by requiring only generators above 100 MVA with unit capacity factors above 5 % to test, about 30% of the installed generation in New England does not require model validation. We believe this is a large portion of the generation that is being exempted. Additionally, the low capacity factor units will likely be running during the periods when the system is being stressed the most and reliable operation is being most challenged. We realize that a model for the generators and associated equipment is

Organization	Yes or No	Question 3 Comment
		supplied in accordance with MOD-012 but we feel the accuracy of such models may be limited and a higher percentage of generator validation is required. **As discussed in the Comment Form with the first posting of the draft MOD-026 standard, the SDT considered the extent of the facilities to be verified and how to reflect this in the "applicability" of this proposed standard. As a basis, the SDT recognized that the excitation system models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the Field Test, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the exciter models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA thresholds corresponding to 80% of connected MVA or greater for each Interconnection are proposed. It is recognized that certain boundaries within an interconnection, such as BA boundaries, may have more or less than 80% of the connected MVA.** **The SDT further believes that a minimum unit interconnection of >100 kV, consistent with the Compliance Registry Guidelines, is appropriate. Finally, the SDT believes that the standard should apply to units with a capacity factor such that they are on-line 400 hours or greater a year. The SDT believes that these three applicability thresholds will result in substantial accuracy improvement to the excitation models and associated Reliability based limits determined by dynamic simulations, while not unduly mandating costly and time consuming verification efforts. Footnote 4 is intended to allow the Transmission Planner to request model information, possibly leading to model verification, for units which fall within the NERC Compliance Registry but are not of the base Applicability of this proposed standard.**

Organization	Yes or No	Question 3 Comment
		Also, the SDT does recognize that regional variances can be considered if a Region desires to include additional unit MVA in this standard. Footnote 4 should be changed to allow verification of generator models not required under the applicability to be at the discretion of the Transmission Planner. In some areas of the system, generator models have a considerable impact on dynamic performance and model accuracy is critical. **Footnote 2 (in the current draft of the standard) is intended to allow the Transmission Planner to request model information, possibly leading to model verification, for "technically justified" units which fall within the NERC Compliance Registry but are not of the base Applicability of this proposed standard. Per Footnote 2, a "technically justified" unit is one whose model response does not match the actual equipment response. Industry disagreed with a GV SDT proposal to expand the concept of "technical justification" to include units that were identified through a study to contribute to a stability limit.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Ingleside Cogeneration LP	No	Ingleside Cogeneration believes that Item 4.2.4 under the "Applicability" section was intended to capture the concept that a Planning Coordinator's request for additional information is limited to NERC-registered units. **Your interpretation is correct** However, the language of requirement R5 will predominate, and it reads as follows:"R5. Each Generator Owner shall provide a written response to its Planning Coordinator, within 90 calendar days following receipt of a technically justified request from the Planning Coordinator to perform a model review of any unit/plant NOT INCLUDED IN THE APPLICABILITY (our emphasis) that includes one of the following" This provides clear instruction that the entire Applicability section may be

Organization	Yes or No	Question 3 Comment
		ignored - even Item 4.2.4. **Item 4.2.4 has been clarified that only units included in the thresholds listed in the NERC registry criteria would be applicable. The GV SDT feels that this covers the concern of Requirement R5 being misinterpreted** We suggest the following language instead:"R5. Each Generator Owner shall provide a written response to its Planning Coordinator, within 90 calendar days following receipt of a technically justified1 request from the Planning Coordinator to perform a model review of any NERC-REGISTERED unit/plant not included in the Applicability that includes one of the following"1 Technical justification is achieved by demonstrating that the simulated unit or plant response does not match the measured unit or plant response Please notice that we also added the footnote under Item 4.2.4 to R5. Although this update is essentially a duplicate, it leaves no doubt to the limits of an exceptional model validation request by the Planning Coordinator. Secondly, MOD-026-1 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. We believe that the Planning Coordinator must first engage these entities before issuing such a request to the GO. **It is expected that the vast majority of the time, the Transmission Planner will work with the Generator Operator to resolve model issues for units that are not in the base applicability. The requirement does provide structure to such collaboration to ensure that it can be made to occur in case one of the parties is otherwise unwilling, and to ensure that the required process is bounded with reasonableness.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Duke Energy	No	Footnote 4 - strike the phrase "or plant" in both places, since this only applies to a unit. Also add the phrase "and by demonstrating a reliability need" to the end of

Organization	Yes or No	Question 3 Comment
		Footnote 4. Otherwise, this standard could be made applicable to a small unit that has no impact on reliability.
Response: Thank you for your comment. Though it would admittedly be a rare occurrence, the use of the technical justification concept per Footnote 2 in the current draft of the standard could also apply to a plant. The language in 4.2.4 has been modified to make it clear that only units that meet the NERC Registry Criteria thresholds will be considered.		
Ameren	No	We believe and recommend that this should be the responsibility of the Transmission Planner rather than the Planning Coordinator. At a minimum the language should state "Planning Coordinator and Transmission Planner".
Response: Thank you for your comment. Based on your and other comments, the SDT decided to replace "Planning Coordinator" with "Transmission Planner" in the standard. The Functional Model for the Transmission Planner is more in line with the task described in the standard.		
Cowltiz PUD	No	Technical justification should also include reasonable demonstration that the improved model will improve the Reliability of the Bulk Electric System.
Response: Thank you for your comment. The SDT believes that any correction of any excitation control system model of a unit that is beyond the MVA thresholds set by the Registry Criteria results in more accurate dynamic simulation assessments which does reasonably improve the reliability of the Bulk Electric System.		
Los Angeles Department of Water and Power		LADWP recommends that "technical justification" is defined and/or replaced with more specific language, i.e.:"Based on the latest round of industry feedback, the GVSDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly leading to model verification) only if documentation such as model structure and data values for the

Organization	Yes or No	Question 3 Comment
		excitation control system demonstrates the ....”
Response: Thank you for your comment. The SDT believes that the term “technical justification” is adequately defined per the footnote.		
Texas Reliability Entity	Yes	(a) R5 should be limited to generating units and plants that meet the Registry Criteria. For clarity, we suggest rewording R5 with “...perform a model review of any generation unit or plant meeting the Registry Criteria, but not included as an applicable unit in Section 4.2, that includes one of the following...”. **The SDT agrees that more clarity could be achieved and thus, in response to yours and other comments, revised the verbiage to include the phrase “…that meets NERC registry criteria….”.** (b) Does similar language (i.e. section 4.2.4) need to be added to MOD-027-1? **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 and active power/frequency control system model for a unit not specified in the standard Applicability section. The GVSDT does not believe that it is likely that the turbine/governor and Load control and active power/frequency control system will contribute to a stability limit because governor response is not consistent from one frequency excursion event to the next. Please refer back to the GVSDT responses to comments for MOD-027 for additional information.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Arizona Public Service Company	Yes	The SDT has done a great job. The requirement is simple, clearer and supports reliability.

Organization	Yes or No	Question 3 Comment
Response: The SDT thanks you for your comment.		
Southern Company	Yes	Allowing a Planning Coordinator to request additional model information only if technical justification demonstrates a mismatch between the measured unit response and the model's predicted response is appropriate. Even if the unit was a contributor to a stability limit, additional model information is really only needed if the model did not sufficiently emulate actual equipment response.
Response: The SDT thanks you for your comment.		
American Electric Power	Yes	The team might wish to consider if the Transmission Planner should also be included in the applicable facilities 4.2.4 and 5.Point of clarification: one does not "register" units, rather entities are registered for NERC functions.
Response: Thank you for your comment. Based on your and other comments, the SDT decided to replace "Planning Coordinator" with "Transmission Planner" in the standard. The Functional Model for the Transmission Planner is more in line with the task described in the standard.		
Austin Energy	Yes	The standard is not applicable to the Planning Coordinator. Does the SDT mean TP?
Response: Thank you for your comment. Based on your and other comments, the SDT decided to replace "Planning Coordinator" with "Transmission Planner" in the standard. Thank you for your comment. The Functional Model for the Transmission Planner is more in line with the task described in the standard.		
Georgia Transmission Corporation	Yes	Requirement 5 seems to imply that GO's must provide a written response regarding units below the Registry Criteria unit MVA thresholds (< 20MVA) if a Planning Coordinator provides a technically justified request to perform a model review. Can

Organization	Yes or No	Question 3 Comment
		the SDT confirm this intent? **No - units that could apply to Requirement 5 are units which are below those which would be included per the standard's Applicability section but above units which are included in the NERC Registry Criteria. Also, the SDT decided to replace "Planning Coordinator" with "Transmission Planner" in the standard. The Functional Model for the Transmission Planner is more in line with the task described in the standard.** Additionally, there could be some confusion with the language as written to imply the PC's "technical justification" includes the bulleted items of R5. **The term "technically justified unit" is defined in the footnote associated with the first occurrence of the term in Section 4.2.4.** GTC is assuming the SDT's intent is for the "GO's written response" to include the bulleted items and therefore requests additional clarity. GTC recommends the following: Each Generator Owner shall provide a written response to its Planning Coordinator, within 90 calendar days following receipt of a technically justified request from the Planning Coordinator to perform a model review of any unit/plant not included in the Applicability. The written response shall include one of the following [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]: o Details of plans to verify/correct the model documentation and data as needed (in accordance with Requirement R2) o Corrected model documentation and data including the source of revised model data. **The bulleted items in Requirement R3 define the types of written responses that, if received from their Transmission Planner, the Generator Owner would have to respond to per the parameters detailed in the main body of the requirement.**

Organization	Yes or No	Question 3 Comment
Response: The GVSDT thanks you for your comment. Please see responses above.		
Southwest Power Pool Standards Development Team	Yes	
Puget Sound Energy	Yes	
Dominion	Yes	
Imperial Irrigation District (IID)	Yes	
Western Electricity Coordinating Council	Yes	
Luminant Power	Yes	
Tennessee Valley Authority GO/GOP	Yes	
PacifiCorp	Yes	
Dynegy	Yes	
PSEG	Yes	
Manitoba Hydro	Yes	
Independent Electricity System Operator	Yes	
Xcel Energy	Yes	

Organization	Yes or No	Question 3 Comment
American Transmission Company, LLC	Yes	
Luminant Energy	Yes	
South Carolina Electric and Gas	Yes	
GenOn Energy	Yes	
Essential Power, LLC	Yes	
FirstEnergy Corp	Yes	
Southern California Edison Company	Yes	
American Wind Energy Association	Yes	
Pepco Holdings Inc. & Affiliates		No comment
Indiana Municipal Power Agency		no comment

4) To clarify concerns regarding calculating unit capacity factor, the SDT has incorporated into the standard the capacity factor calculation specified in Appendix F of the GADS Data Reporting Instructions. Do you agree with this revisions? If not, please explain in the comment area below.

Summary Consideration: The majority of the industry commenters agreed with specifying the capacity factor calculation in Appendix F of the GADS Data Reporting Instructions. Also, many of the commenters pointed out that neither the net or gross calculation was specified in the standard and suggested the SDT use the "net" calculation. As such, the SDT has revised the draft standard to reference the net capacity factor calculation in Appendix F of the GADS Data Reporting Instructions. This revision was made in Section 4.2 Facilities and in Footnote 4 (now Footnote 2). Finally, the SDT moved the details of the capacity factor exemption concept form a footnote in the Applicability section to a row (Row 7) in the Periodicity Table. The team thought that would be appropriate as the Periodicity Table already included the "equivalent" unit concept (Row 4)

Organization	Yes or No	Question 4 Comment
Texas Reliability Entity	No	We disagree with using a capacity factor to determine which units need to comply with this Standard. The requirements should apply to all generating units meeting the MVA thresholds, regardless of capacity factor. If the SDT decides to use the capacity factor, then the applicable facility definition needs to clearly state whether it is using the gross or net capacity per the GADS definition. The SDT also needs to define how new generation units will be captured under this Standard. In our opinion, it is unacceptable to wait three years to determine if a new generation unit meets the capacity factor limit before it is determined to be an "applicable unit".
Response: Thank you for your comment. The SDT believes that capacity factor is the best available tool for use to determine a threshold for applicability. Capacity factor has been defined and is already being used in GADS reporting. This standard has been revised to specify the "net capacity factor" is to be used. Units with less than 5% capacity factor are not likely to be on-line during a system event, and also are difficult to test because they are operated so rarely. New units are required to be verified within one year (refer to the table in Attachment 1).		
Luminant Power	No	Appendix F of the GADS Data reporting has two Capacity Factor calculations (Gross

Organization	Yes or No	Question 4 Comment
		and Net). The standard should specify Net Capacity Factor.
ank you for your comment. The standard has been revised to specify the "net capacity factor" is to be used. The SDT moved the capacity factor exemption concept form a footnote in the Applicability section to a row (Row 7) in the Periodicity Table. The team would be appropriate as the Periodicity Table already included the "equivalent" unit concept (Row 4)		
PacifiCorp	No	If the GVSDT intends to incorporate definitions or calculations from Appendix F of the GADS Data Reporting Instructions, the relevant information needs to be expressly incorporated, perhaps in an additional attachment to the standard. Requirements that refer to outside materials are not helpful and should be avoided (notwithstanding the desire to avoid a future need to modify the standard to the extent that Appendix F is amended from time to time in the future).
Response: Thank you for your comment. The SDT believes the reference to the GADS reporting document is appropriate because it is well established and is now a NERC requirement. Including the capacity factor definition into this standard would create the additional problem of having to revise this procedure if the GADS reporting document is revised.		
Luminant Energy	No	Appendix F of the GADS Data reporting has two Capacity Factor calculations (Gross and Net). The standard should specify Net Capacity Factor.
Response: Thank you for your comment. The standard has been revised to specify the "net capacity factor" is to be used.		
Duke Energy	No	Need to specify "net" or "gross" capacity factor for the calculation.
Response: Thank you for your comment. The standard has been revised to specify the "net capacity factor" is to be used.		
Austin Energy	No	The NERC Glossary is the correct reference for definitions used in the Standards. Referencing GADS is not appropriate.
Response: Thank you for your comment. The SDT believes the reference to the GADS reporting document is appropriate because it is well established and is now a NERC requirement. The SDT believes that the reference to the GADS reporting document is		

Organization	Yes or No	Question 4 Comment
appropriate, and as such, since it is well established, there is no need to make it a defined term in the NERC Glossary.		
Georgia Transmission Corporation	No	We ought to be able to verify FIDVR mitigating machines below 5% capacity factor.
Response: Thank you for your comment. Units that are below the 5% capacity factor but are equal to or greater than the MVA thresholds in the Registry Criteria could be subjected to the terms in Requirement R5 if there is evidence that the equipment's actual response does not match the model's predicted response.		
Northeast Power Coordinating Council	Yes	While supporting the clarification of capacity factor concerns, there is concern with the exclusion for units with less than a five percent capacity factor. See comments provided to Question 3. Average Capacity Factor should be defined.
Response: Thank you for your comment. The SDT believes that capacity factor is the best available tool for use to determine a threshold for applicability. Capacity factor has been defined and is already being used in GADS reporting. Units with less than 5% capacity factor are not likely to be on-line during a system event, and also are difficult to test because they are operated so rarely.		
ISO New England Inc	Yes	While we support the clarification of capacity factor, please note our concerns with an exclusion for units with less than a five percent capacity factor that are included with question 3.
Response: Thank you for your comment. The SDT believes that capacity factor is the best available tool for use to determine a threshold for applicability. Capacity factor has been defined and is already being used in GADS reporting. Units with less than 5% capacity factor are not likely to be on-line during a system event, and also are difficult to test because they are operated so rarely.		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration strongly agrees with the SDT's use of the capacity factor calculation used in the GADS system. It is always important to establish links to time-tested parameters - and eliminating any possibility that some other calculation is used.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment.		
Los Angeles Department of Water and Power	Yes	LADWP agrees with this revision.
Southwest Power Pool Standards Development Team	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Puget Sound Energy	Yes	
Dominion	Yes	
MRO NSRF	Yes	
Imperial Irrigation District (IID)	Yes	
PPL Electric Utilities and PPL Supply NERC Registered Organizations	Yes	
Tennessee Valley Authority GO/GOP	Yes	
Arizona Public Service Company	Yes	
Southern Company	Yes	

Organization	Yes or No	Question 4 Comment
Massachusetts Attorney General	Yes	
Dynegy	Yes	
AECI	Yes	
PSEG	Yes	
Manitoba Hydro	Yes	
Independent Electricity System Operator	Yes	
Xcel Energy	Yes	
American Transmission Company, LLC	Yes	
South Carolina Electric and Gas	Yes	
GenOn Energy	Yes	
Essential Power, LLC	Yes	
Ameren	Yes	
FirstEnergy Corp	Yes	
Southern California Edison	Yes	

Organization	Yes or No	Question 4 Comment
Company		
Cowltiz PUD	Yes	
American Wind Energy Association	Yes	
Indiana Municipal Power Agency	Yes	
Pepco Holdings Inc. & Affiliates		No comment

5. **Do you have any other comment, not expressed in questions above, for the GVSDT regarding MOD-026-1?**

Summary Consideration:

The following modifications to the draft standard were incorporated as a result of industry responses to this question:

1) **The SDT replaced “Planning Coordinator” with “Transmission Planner” in the standard. The Functional Model for the Transmission Planner is more in line with the task described in the standard.**
2) **Requirement R2 Part 2.2 has been re-worded and merged into Part 2.1. The new verbiage makes it clear that the entity performing the model verification has flexibility regarding if the model should be represented by individual unit or plant aggregate models or any combination therein as dictated by the specific situation. This merger also results in appropriate mapping to the VSLs.**
3) **A significant number of industry commenters opposed the use of the term “bulk power system” in the Applicability section. The SDT did not mean to convey a modification in the breadth of units which would be covered by the standard as “bulk power system” is a term used in the Compliance Registry. But based on the concerns expressed by industry, the SDT has replaced the term “bulk power system” with the NERC defined term “Bulk Electric System”.**
4) **The SDT has refined section 4.2.1, 4.2.2, and 4.2.3 of the Facilities section under Applicability.**
5) **The SDT refined Part 2.1 to clarify the use of individual and aggregate models for plants.**
6) **The SDT has re-formatted the Periodicity Table (Attachment 1) to make it clearer that the table is included.**
7) **Revised the Periodicity Table (Attachment 1) extensively for clarity, including removing specificity regarding when the voltage excursion used for model verification had to be captured. This resulted in a modification of the required times for re-verifying the model for exception (R3 and R4) type activities.**
8) **The SDT made corrections to VSL verbiage.**
9) **The SDT made corrections to a reference in Attachment 1 to 356 days (changed to 365 days).**
10) **In Requirement R5, in describing checking the actual equipment to determine if updated model data could be obtained, the expression “walk down” was replaced by “on-site review” of the equipment.**
11) **The term “inertia” was modified to “total inertia” in sub part 2.1.3 as some industry commenters expressed concern that reference to “inertia” only would lead to submittal of an inertia constant reflective only of the generator, as opposed to all of the mass attached to the shaft.**
12) **In Requirement R2, Part 2.1.1, the specific reference to point of interconnection has been removed. The location where the unit’s response is measured is left to the model verification entity.**
13) **The second bullet in Requirement R1 has been modified to be the same style and sentence structure used in the first bullet of R1.**

14) The SDT has removed the term “generating plant / Facility” and replaced it with “individual generating plant consisting of multiple generation units that are directly connected at a common BES bus” at the top level of the Facilities section (A4.2).

15) The SDT modified the phrase "generator excitation control system and plant volt/var control functions” to “generator excitation control system or plant volt/var control functions” to recognize that the use of the phrase “or” is technically correct the vast majority of the time.

Organization	Yes or No	Question 5 Comment
Lower Colorado River Authority	Negative	1. Requirement R1- Transmission Planner should be replaced with (Planning Authority, Reliability Coordinator, or Resource Planner) and a requirement placed on the (Planning Authority, Reliability Coordinator, or Resource Planner) to provide data to the Transmission Planner should be added. In ERCOT, the (Planning Authority, Reliability Coordinator, or Resource Planner) and Transmission Planner are separate entities and the (Planning Authority, Reliability Coordinator, or Resource Planner) maintains this information on the ERCOT website, is the first point of contact for new generator interconnection requests, and is the recipient of generation data that is revised after generator compliance testing. The following shows how LCRA TSC’s suggested change should be applied to the first paragraph of R1. Transmission Planner should be replaced with (Planning Authority, Reliability Coordinator, or Resource Planner) in the remaining elements of R1. “Each Transmission Planner (Planning Authority, Reliability Coordinator, or Resource Planner) shall provide the following instructions and model data to its requesting Generator Owner or Transmission Planner within 90 calendar days of receiving a request for those instructions or model data:” 2. Requirement R2 - Transmission Planner should be replaced with (Planning Authority, Reliability Coordinator, or Resource Planner) and Transmission Planner. 3. Requirement R3 - Transmission Planner should be replaced with Planning Authority, Reliability Coordinator, or Resource Planner and Transmission Planner in the first paragraph. Transmission Planner should be replaced with (Planning Authority, Reliability Coordinator, or Resource Planner) or Transmission Planner in

Organization	Yes or No	Question 5 Comment
		the sub parts of R3. 4. Requirement R4 - Transmission Planner should be replaces with (Planning Authority, Reliability Coordinator, or Resource Planner) and Transmission Planner. In addition, the requirement to provide the data within 180 days seems excessively permissive since this is after a change has been implemented on the system. LCRA TSC recommends 30 days. The second bullet in Section 4.2.3.2 is confusing. o Each generating plant / Facility comprised consisting of individual generating units less than 20 MVA (gross nameplate ratings). 5. Requirement R5 - Allowing generators up to 10 years from the date of regulatory approval to become compliant as stated in Section 5 seems excessively long. In addition, the effective date described in Section 5 appears to be applicable to new generation and modifications to existing generating units, meaning a new or newly modified generating facility would have up to ten years to provide the data. LCRA TSC believes that MOD 26 should be effective immediately to new or newly modified generators who interconnect after the standard is adopted. 6. Requirement R6 - In R6.3, the concern should be when an excitation system and/or volt/var control does not contribute to a well-damped generator response following a fault. LCRA TSC recommends the following changes. “ For an otherwise stable simulation, a disturbance simulation results in the excitation control and plant volt/var control function model does not contribute to a well-damped generator response.”
Response: Thank you for your comment. Regarding the responsibilities that would be assigned to the Transmission Planner in the draft standard, the SDT believes that this arrangement lines up with the vast majority of North American utilities current business practices regarding interactions between generation and transmission entities for collaboration of generator dynamic models. Given that ERCOT is the exception, a regional variance could be considered. Alternatively, the Transmission Planner could		

Organization	Yes or No	Question 5 Comment
delegate the responsibility to others, include their Planning Authority. The transmission planner must maintain a model of their system to meet the TPL standards, but they need input from other embedded entities for generation and other equipment models. For the purposes of the standard, there must be a clear assignment of responsibilities and using "or" in the assignment leaves ambiguity. The SDT has removed the term "generating plant / Facility" and replaced it with "individual generating plant consisting of multiple generation units that are directly connected at a common BES bus" at the top level of the Facilities section (A4.2). As a result of comments received from the prior posting, the standard drafting team extended the time to 180 days to allow more time to work through the technical challenges relating to these models. In order to meet the requirements of the standard, the generator owner needs to have time to schedule someone to test the units, and there needs to be flexibility to allow for units that are not always running, and for such units, often when they are running there are "no touch" rules in place. The 180 days is to provide for enough flexibility to balance the data need with required expenses (especially those associated with running some units) associated with meeting these requirements. New units are required to be verified within one year (refer to the table in Attachment 1). With regard to Requirement R6.3 the SDT believes the language as presently drafted already addresses the commenters stated concerns.		
BC Hydro and Power Authority	Negative	BC Hydro is voting Negative as the motivation and purpose for the 10 year recurring validation period is not clearly defined. BC Hydro recommends supplying better supporting justification, or consideration should be given to modify this criteria, ie remove the blanket 10 year requirement. In place of the blanket interval, alternative criteria recommended are a) for machines equipped with digital excitation and governor control, no recurring testing required because there is nothing that can change (software doesn't drift), b) for machines with either or both non-digital exciter and governor control, recurring testing should be required every X years (analog control is more susceptible to setting drift and other issues) BC Hydro supports the remaining reasons for requiring validation.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. The SDT believes that the ten year periodicity is appropriate and has received industry support for this concept, specifically as a result of the first posting. Digital excitation systems settings can be modified, and there are other components in the closed loop system that can degrade with heat and stress over time (SCRs, discrete electronic components, etc).		
Southwest Transmission Cooperative, Inc.	Negative	Because NERC has made clear that standards are enforced against the BPS and not the BES, the applicability section should be modified to state clearly that it applies to Facilities that are part of the BES. Otherwise small generators that do not affect reliability could be impacted by these standards. NERC enforcement has made this clear in response to comments on CAN-0016 that the CIP-001 standard applied only to the BES. They stated clearly: "According to Section 39 of the Energy Policy Act of 2005, NERC defines the Interconnected Power Grid as the Bulk Power System. Unless otherwise restricted by a standard, it is applicable to the BPS." **Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.** The following comments pertain to PRC-024: Use of "new or existing" as a description for the generators in Requirements R1, R2 and R5 is confusing. **This phrase has been removed from Requirements R1 and R2 in PRC-024.** What exactly constitutes new and why is it relevant? The requirements are performance requirements that apply to in-service generators so how does new help explain this further. The footnote in Requirement R5 only further confuses the situation since it is not included in Requirements R1 and R2. Part of the confusion likely centers around Requirement R5 applying to maintaining new generators frequency and voltage excursion performance as well as designing and building it. If "maintain" was removed from Requirement R5, we believe "new" could be removed from Requirement R1 and R2 and they essentially become the maintenance

Organization	Yes or No	Question 5 Comment
		requirements. Furthermore, "new and existing" is not used consistently within other requirements such as Requirement R4. It is not obvious why it would not apply to Requirement R4 it if applies to Requirements R1 and R2. **A new unit is one that is not addressed in Footnote 2 which are units "generating units previously commissioned, or generating units under construction, or generating units with an executed interconnection agreement or power purchase agreement by the effective date of PRC-024-1 Requirement R5." Requirement R5 applies to future units which must be built to meet the performance requirements of PRC-024. There is no allowance for exceptions or exemptions from any requirement in PRC-024 except as stated in Parts 5.1 – 5.6. Requirement R5 requires the design, construction and maintenance of any future unit once PRC-024 becomes enforceable.** Neither Requirement R1 nor R2 state within the main body of the requirement that the Parts are intended to be exceptions to the requirement. For clarity, there should be a statement (i.e. except when the Parts 1.1 and 1.2 are met) within the requirement the makes this clear. **Requirement R1 now reads, in part, "…with the following exceptions:"Requirement R2 was revised to make the requirement clearer.** For Requirements R1 and R2, it is not clear if the sub-parts are the only reasons that allow for exceptions if other equipment limitations exceptions are allowed. Other equipment limitations should be allowed, and these requirements should be clarified to allow them. **Exceptions for other equipment limitations are addressed under Requirement R3.** As written, Requirement R5 appears to be assumed to apply to a new generator in perpetuity. We draw this conclusion from the inclusion of "maintain" in the requirement. We think it makes more sense to have this requirement apply only to designing and building a new unit and then have the requirements that apply to existing units apply to the maintenance of the new units once they are established.

Organization	Yes or No	Question 5 Comment
		You assumption is correct. That is the intent of Requirement R5. The standard does not appear to allow "new" generating units to have frequency and voltage excursion performance limited by equipment. It should allow "new" equipment as it experiences normal wear and tear as well as damage for any other reasons to document its equipment limited frequency and voltage performance and communicate it similar to Requirements R1 through R3. **Requirement R5 is written with an implementation plan of six years after approval before it is enforceable. This is to allow sufficient time for manufacturers to design and build generation facilities that can meet the performance requirements. Manufacturers have representation on the GVSDT and are aware of this.** Otherwise, a Generator Operator with a "new" generator that has damaged equipment will be forced between operating the unit in a limited manner providing reliability support to the BES and possibly in violation of this standard or taking a forced outage to avoid violating the standard and experiencing escalated penalties for knowingly violating the standard. **Requirement R5, Part 5.5 (was Part 5.6) allows for temporary exemptions to be granted by the Reliability Coordinator in such instances.** We do not believe that Reliability Coordinator is the proper entity to grant a temporary exemption in Part 5.6. Rather, it is the Planning Coordinator that should grant the exemption. Furthermore, this is not consistent with other requirements such as Parts 2.1 and 2.1.1 that specify the Transmission Planner grant the exemption. Of course, Part 5.6 would not be necessary if Requirement R5 did not deal with maintaining the unit and allowed the other requirements that apply to existing units to address maintenance. **Requirement R5 is a performance requirement and is more appropriately addressed in a real-time environment. The GVSDT believes that the Reliability Coordinator is the appropriate entity.** We do not believe the VRFs for Requirements R1, R2 and R5 warrant High VRFs. The

Organization	Yes or No	Question 5 Comment
		BES is already operated within each BA and TOP for the loss of a single unit. Tripping of a generator due to a frequency or voltage excursion is an uncommon event that is already planned for. It is highly unlikely that tripping of such a generator or even several generators will lead to instability, system separation or cascading which is required for the VRF to be High. Furthermore, by setting the VRF to High, this increases the potential that every single unit outage could become subject to a Compliance Violation Investigation which is simply not necessary. **The VRF for Requirements R1, R2 and R5 have been revised to "Medium".**
Response: The GVSDT thanks you for your comments. Please see responses above.		
Ohio Edison Company	Negative	FE appreciates the hard work of the drafting team but has some concerns that we ask be addressed so that we can support the standard on the next ballot. Please see our comments and suggestions submitted through the formal comment period.
Response: The SDT thanks you for your comments and has strived to properly consider and respond to all comments and suggestions. Please refer to our responses to your comments.		
Oncor Electric Delivery	Negative	In a deregulated market, the Balancing Authority (BA) and Planning Authority (PA) are in the best position to provide a more strategic look at gathering this type of information and ensuring the necessary broad distribution. As a result, the receiving and requesting of modeling data from a Generator Owner (GO) should be the responsibility of the PA or the BA and not the Transmission Planner. This approach provides a single clearinghouse for generator data, ensuring accuracy and consistency, to and from the GO which then can accessed by any impacted Registered Entities.
Response: Thank you for your comment. After much consideration, and a review of the functional model, the SDT realized that the TP is the appropriate entity to receive the modeling data. In instances where the BA or PA aggregates the model data, the TP		

Organization	Yes or No	Question 5 Comment
is delegating their responsibility under the functional model to other entities.		
Lakeland Electric	Negative	LAK is a member of FMPA, please refer to their comments.
Wisconsin Energy Corp.	Negative	MOD-026-1: Requirement R2.1.1 requires modification to properly include the Transmission Planner in the effort to compare the model response to the recorded response. **The SDT has drafted the standard such that the Generator Owner is the "owner of the model". The vast majority of industry supports this concept, as demonstrated in response to a specific question on the Applicability posed in a prior posting. Peer review type requirements (for example, Requirement R3) have been drafted that can result in the inclusion of the Transmission Planner in a process to review models which result in issues requiring collaboration.** Requirement R2.2 also needs more flexibility for the Generator Owner to provide individual model information in place of an aggregate model for multiple small units. **Requirement R2 Part 2.2 has been re-worded and merged into Part 2.1. The new verbiage makes it clear that the entity performing the model verification has flexibility regarding if the model should be represented by individual unit or plant aggregate models or any combination therein as dictated by the specific situation.** Also, we oppose the addition of Requirement R5 as unnecessary to the reliability of the BES. This Requirement should be removed from the draft Standard. **The SDT believes that Requirement R5 is necessary to the reliability of the BES. This requirement was added by the SDT in response to industry asking if a transmission entity should be allowed to identify additional units beyond those identified in the base Applicability. The base applicability, contains unit and plant MVA thresholds which include a subset of those units which are identified in the NERC Compliance Registry. The ability of the Transmission Planner to request model information is well bounded and defined to ensure that the Generator**

Organization	Yes or No	Question 5 Comment
		Owner is not unduly burdened with frivolous requests for model information.
Response: Thank you for your comment. Please see responses above.		
Omaha Public Power District	Negative	OPPD has signed on to MRO's NSRF comments
Minnkota Power Coop. Inc.	Negative	Please see comments submitted by the MRO NSRF.
MidAmerican Energy Co.	Negative	Please see MidAmerican and MRO NSRF Comments.
Madison Gas and Electric Co.	Negative	Please see MRO NSRF comments
Great River Energy	Negative	Please see MRO NSRF comments.
Muscatine Power & Water	Negative	Please see the comments submitted by MRO NSRF
Dairyland Power Coop.	Negative	See MRO NSRF comments.
U.S. Army Corps of Engineers	Negative	See MRO/NSRF comments
Response: Thank you for your comment. Please see responses to MRO comments.		
Fort Pierce Utilities Authority	Negative	Please see separately submitted formal comments by Florida Municipal Power Agency.
Gainesville Regional Utilities	Negative	We support FMPA's position on this matter.
Lakeland Electric	Negative	Please see FMPA comments
Response: Thank you for your comment. Please see responses to FMPA comments.		
Great River Energy	Negative	Please see the formal comments submitted by Aces Power Marketing.

Organization	Yes or No	Question 5 Comment
North Carolina Electric Membership Corp.	Negative	Please see the formal comments submitted by ACES Power Marketing.
Response: Thank you for your comment. Please see responses to ACES comments.		
Atlantic City Electric Company	Negative	Refer to comments submitted by Pepco Holdings Inc and Affiliates.
Response: Thank you for your comment. Please see responses to Pepco comments.		
Wisconsin Electric Power Co., Wisconsin Electric Power Marketing	Negative	Requirement R2.1.1 requires modification to properly include the Transmission Planner in the effort to compare the model response to the recorded response. **The SDT has drafted the standard such that the Generator Owner is the "owner of the model". The vast majority of industry supports this concept, as demonstrated in response to a specific question on the Applicability posed in a prior posting. Peer review type requirements (for example, Requirement R3) have been drafted that can result in the inclusion of the Transmission Planner in a process to review models which result in issues requiring collaboration.** Requirement R2.2 also needs more flexibility for the Generator Owner to provide individual model information in place of an aggregate model for multiple small units. **Requirement R2 Part 2.2 has been re-worded and merged into Part 2.1. The new verbiage makes it clear that the entity performing the model verification has flexibility regarding if the model should be represented by individual unit or plant aggregate models or any combination therein as dictated by the specific situation.** Also, we oppose the addition of Requirement R5 as unnecessary to the reliability of the BES. This Requirement should be removed from the draft Standard. **The SDT believes that Requirement R5 is necessary to the reliability of the BES. This requirement was added by the SDT in response to industry asking if a transmission entity should be allowed to identify additional units beyond those identified in the base applicability. The base applicability contains unit and plant**

Organization	Yes or No	Question 5 Comment
		MVA thresholds which include a subset of those units which are identified in the NERC Compliance Registry. The ability of the Transmission Planner to request model information is well bounded and defined to ensure that the Generator Owner is not unduly burdened with frivolous requests for model information.
Response: Thank you for your comment. Please see responses above.		
Consolidated Edison Co. of New York	Negative	See NPCC electric group comments
Response: Thank you for your comment. Please see responses to NPCC comments.		
Occidental Chemical	Negative	See submitted comments on behalf of Ingleside Cogeneration LP
Response: Thank you for your comment. Please see responses to Ingleside comments.		
Northern Indiana Public Service Co.	Negative	There is a concern about inconsistencies between the Standards and Appendices
Response: Thank you for your comment. The SDT has reviewed and simplified Attachment 1 and believe that it is consistent with the draft standard.		
Old Dominion Electric Coop.	Negative	This standard needs a QR as they are many inconsistencies in the language used, I only pointed out a few major errors: R2: You say PC, should be PC or PC must be included in the Applicability Section. **The SDT could not find use of term PC in Requirement R2.** R2: Replace 'Part's with 'Requirements' R2.1: requires GO to comply with a specified TP model, this may not be economic or even feasible to do so. **Regarding 'Parts' vs. 'Requirements', NERC specifically changed this language to**

Organization	Yes or No	Question 5 Comment
		'Parts' based on the official definition of this term. **Regarding Requirement R2, Part 2.1, the TP models (which are typically standard library models in the PSS/e and PSLF simulation programs) are widely available and representative of excitation systems and volt/var control on all types of generation technologies. While there is no requirement for quality of match between test and simulation, there is a need to assure the TP can use the submitted model in their bulk system analysis (also expanded by language in R6). This is the reason for the language around models acceptable to the TP.** **If your question is related to performance, there is no performance requirement in this standard and therefore there is no need to alter equipment hardware or settings based on these TP models.** R2.2: Parts and Requirements R3: This conflicts with R2 on how the GO must present the data to the TP... **These requirements intend to address separate activities. Requirement R2 is intended to define what is required in the verification. Requirement R3 requires the GO to respond to a TP inquiry.** R5: GO should be allowed to challenge thier units being included by the TP as technically justified! Market issues in RTOs and ISOs. **The intent of Requirement R5 is for TPs to use technical justification for validating models that meet NERC reliability criteria but did not meet applicability criteria. The GO has 90 days to respond. If the GO decides to verify the model, they have a year to do so. The SDT believes that since technical justification requires demonstration the model does not match actual equipment response, this requirement is reasonable.** R6: Perts and Requirements again. Some of my comments are minor, some are deal breakers (R3 and R5). **Regarding 'Parts' vs. 'Requirements', NERC specifically changed this language to**

Organization	Yes or No	Question 5 Comment
		'Parts' based on the official definition of this term.
Response: Thank you for your comment. Please see responses above		
Alabama Power Company	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
Gulf Power Company	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
Response: Thank you for your comment. Please see responses to those comments.		
Pepco Holdings Inc. & Affiliates		Agree with the generating unit nameplate thresholds as defined in this standard, but do not agree with eliminating the 100kV interconnection criteria from section 4.2 of this standard and replacing it with the undefined term "bulk power system." This subtle difference greatly expands the applicable scope of the standard from the previous draft version and would now include units that are not defined as being a part of the BES. The term "bulk power system" (BPS) is not defined within this standard, nor is it found in the NERC glossary of terms. Section 215 of the FPA defines the term "Bulk Power System" as follows: (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) and (B) electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. In effect, the statutory term "Bulk Power System" defines the jurisdiction of FERC. On November 18, 2010 FERC issued Order 743 (amended by Order 743A) and directed NERC to revise their definition of "Bulk Electric System" (ref. Project 2010-17) so that the definition encompasses all Elements and Facilities necessary for the reliable operation and planning of the interconnected bulk power system. As such, the applicability of this Reliability Standard should be limited to those generation facilities included in the BES definition, and not those subject to the broader BPS definition. The latest NERC BES definition includes generation resources consistent with the capacity thresholds in the Compliance Registry; however, the 100kV interconnection voltage clause in the

Organization	Yes or No	Question 5 Comment
		BES definition limits the scope to those units necessary for the reliable operation of the interconnected bulk power system. In conclusion, Section 4.2 should be modified to remove the undefined term "bulk power system" and either re-instate the 100kV interconnection constraint, or reference those generation facilities as defined in the NERC BES definition.
Response: We appreciate your thoughtful comments. Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.		
PacifiCorp	Yes.	See below: 1. PacifiCorp does not support the addition of the term "bulk power system" to Section 4.2.2.1 of the "Applicability" section. The term is ambiguous and, in this context, fails to provide the clarity afforded by either the previous language ("at greater than or equal to 100 kV") or the defined term of "Bulk Electric System." PacifiCorp suggests maintaining the existing applicability language, including the "directly connected" qualifier so that the sentence reads as follows: "Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected to the point of interconnection at greater than or equal to 100 kV." **Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.** 2. PacifiCorp believes that the second bullet under Section 4.2.2.2 of the "Applicability" section introduces confusion for registered entities. If we correctly understand the intent of the GVSDT, then please consider the following language to replace the two existing bullets: o "Each individual generating unit greater than 20 MVA (gross nameplate rating), plus an aggregate model for the other generating units of less than 20 MVA at the plant/Facility; and

Organization	Yes or No	Question 5 Comment
		o Where there are no individual generating units greater than 20 MVA in a plant/Facility with total generation greater than 75 MVA (gross aggregate rating), an aggregate model for the generating units of less than 20 MVA." **The SDT has refined section 4.2.2 of the Facilities section under Applicability and Part 2.1 to clarify the use of individual and aggregate models for plants.** 3. PacifiCorp agrees that the addition of sub-Requirement 2.2 is a good clarification, but believe that the language could be further clarified to remove unnecessary confusion by amending the sub-Requirement as follows:"For generating plants/Facilities with total generation greater than the thresholds established in the Applicability section of this standard that are comprised of units that have gross nameplate rating of less than 20 MVA, each Generator Owner shall perform its verification using plant aggregate model(s) that include the information required by Requirement sub-parts 2.1.1 through 2.1.6." **Requirement R2 Part 2.2 has been re-worded and merged into Part 2.1. The new verbiage makes it clear that the entity performing the model verification has flexibility regarding if the model should be represented by individual unit or plant aggregate models or any combination therein as dictated by the specific situation.**
Response: Thank you for your comment. Please see responses above.		
Ameren		(1) The requirements 4.2.1.1 and 4.2.1.2 refer to bulk power system (BPS). We suggest that GVSDT includes definition of BPS in the standard. **Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.** (2) We suggest that GVSDT clearly specify that "point of interconnection" referred to in R2.1.1 to be the same as defined in PRC-024-1.

Organization	Yes or No	Question 5 Comment
		Specific reference to point of connection is removed from R2.1.1. Language has been modified to: "Documentation demonstrating the applicable unit's model response matches the recorded response for a voltage excursion from either a staged test or a measured system disturbance." (3) In Attachment 1, Row 4 it seems to imply to us that some use of "Sister Units" is allowed to meet the requirement. . We suggest that the GVSDT clarify and include this option in the body of the Standard (preferably) or in Attachment 1 as an option? **The proxy or sister unit concept is intended to be a part of Attachment 1. The SDT has re-formatted the Periodicity Table (Attachment 1) to make it clearer that the table is included.** (4) Requirement R2.2 states that an Applicable plant with gross nameplate ratings of the units < 20 MVA should use a plant aggregate model. Can the GVSDT clarify the type of model and provide example for each? **The SDT wants to avoid including specific examples in the standard at risk of creating bias or confusion to its captive audience. That said, a primary reason for this language is to capture variable energy resources (wind and large solar plants) that are widely modeled using an aggregated equivalent generator rather than separately modeling each machine. One example would be using the WECC generic wind models (which are aggregate models) to represent wind plants. Also, Part 2.1 contains refined verbiage makes it clear that the entity performing the model verification has flexibility regarding if the model should be represented by individual unit or plant aggregate models or any combination therein as dictated by the specific situation.** (5) There are 17 technical papers referenced in Section G of the Standard. Would the GVSDT make them available on the NERC website? **Information necessary to obtain copies of these papers is listed in each of the**

Organization	Yes or No	Question 5 Comment
		paper references. (6) For Requirement R3, we did not find anything in the standard that specifies how closely a model response must match the tested response of a generator. We believe that unless this is clearly specified, it could lead to disagreements between the Generator Owner and Transmission Planner over what constitutes a verified model. **The SDT has drafted the standard such that the Generator Owner is the "owner of the model". The vast majority of industry supports this concept, as demonstrated in response to a specific question on the Applicability posed in a prior posting. Requirement R3 is a "peer review" type requirement that can result in the inclusion of the Transmission Planner in a process to review models which result in issues requiring collaboration. However, as owner of the model, the requirement is structured such that the Generator Owner is both responsible and has the final say in collaboration regarding model issues.**
Response: Thank you for your comment. Please see responses above.		
Texas Reliability Entity		1) Applicability: The applicable Facility requirements should be the same for every Standard in this Project! **The applicability of MOD-026 is carefully selected in an attempt to balance the need for verified models with the cost and effort required. The size requirements are selected to assure that 80% of the generation MVA represented has verified models. Also, the effective and implementation dates for the current drafts of MOD-026 and MOD-027 (dynamic model verification standards) are effectively the same.** 2) Section 4.2 should reference the Bulk Electric System definition for generation facilities or Transmission Planner requirements whichever is more inclusive. At a minimum, the BES definition should be used without differences for each interconnection.

Organization	Yes or No	Question 5 Comment
		Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term. 3) Effective Dates: Ten years is too long of an implementation period and should be shortened. The reliability implications of not validating responses within the models are significant. More emphasis (a shorter time frame) should be given to correcting model errors that may lead to (or have led to) improper planning of the system based on the current model results. **The purpose of the initial 10-year implementation period is to give industry sufficient time to perform verification on required units with limited resources to perform the verification activities. The SDT believes that 10 years is a reasonable re-verification period. The standard does include requirements that obligate the Generator Owner to possibly re-verify the model before 10 years upon the occurrence of certain activities, including a change in equipment expected to modify the output of the equipment. The proposed 10-year re-verification period is also supported by an overwhelming majority of comments received from the industry.** 4) The SDT should consider moving the "Consideration for Early Compliance" criteria from Attachment 1 into the Effective Dates section. **The SDT has reformatted Attachment 1 for improved clarity. The consideration for early compliance could be included in section 5, "Effective Date", but we believe the flow of the standard is best if the early compliance information appears in Attachment 1 with the other clarifying criteria.** 5) Regarding Requirements R3 and R4: The inclusion of "or a plan" extends the timeframe associated with getting good modeling data to the TP. What does the Transmission Planner do in the interim? Who is responsible for the use of the unusable or invalid data? Does the unusable or invalid data get used at all (do the plants need to disconnect until "usable" data is provided)? **The draft standard realizes that upon recognition of an issue with the model, the**

Organization	Yes or No	Question 5 Comment
		investigation of the issue and ultimately the implementation of the solution does take time. Both parties will be motivated to resolve the model issue as quickly as possible. Thus, in practicality, the process does require time as it does currently today. The decision on what model to use for dynamic studies in the interim would be made by the Transmission Planner, ideally after consultation with the Generator Owner. 6) Regarding VSLs for R1, R3, R4, R5 and R6: The numbers of days stated in the Severe VSLs need to be reconsidered. For example, in the Severe VSL for R1, no VSL applies if the performance occurs on day 181. **Based on your comment, the SDT has revised the verbiage for the Severe VSL for Requirement R1 to "The Transmission Planner failed to provide the instructions and data to the Generator Owner within 180 calendar days of receiving a request."** 7) Regarding VSL R5: There is reference to Subpart(s) 5.2 and 5.3 in the High and Severe VSL text, but there are no corresponding subparts in the Standard. **Based on your comment, the SDT has revised the verbiage for the High VSL to not include any references to the sub bullets in Requirement R5, and revised the verbiage for the Severe VSL to include " OR The Generator Owner written response failed to indicate one of the sub bullets of Requirement R5."** 8) Regarding Attachment 1: The allowed time to provide usable verified models is far too long. For example, as written there could be a gap of almost two years between the time a TP learns that a model is "unusable" and the time the GO has to provide a verified model. **The SDT drafted the standard recognizing the model verification requires expertise and calendar time. Regarding the specific example offered, the SDT believes that the vast majority of the time, issues regarding model usability will be resolved very quickly. Typical issues include scaling issues, model data typos, incorrect per unit calculations, etc. Typically, a model that is found to be not**

Organization	Yes or No	Question 5 Comment
		useable does not result in the model having to be re-verified. In the interim, after an initial consultation with the Generator Owner, the Transmission Planner may choose to use the prior model. **Also, in part as a goal to further simplify and streamline the Periodicity Table (Attachment 1), the maximum amount of time between the Transmission Planner learns and notifies the Generator Owner that a model is "unusable" and (assuming the Generator Owner decides to verify the model) when the Generator Owner transmits a re-verified model is decreased to 1 year 90 days. (instead of 1 year 270 days as proposed in the previous posting).** 9) In Attachment 1, change "356 days" to "365 calendar days" in the third line of the table for consistency. **The typo error correction has been made.**
Response: Thank you for your comment. Please see responses above.		
Ingleside Cogeneration LP		1. Ingleside Cogeneration LP cannot agree with the change in the applicability section of MOD-026-1, which references generation connected to the "bulk power system" rather than the NERC-defined term "Bulk Electric System". This bypasses the express intent of the NERC Glossary to carefully describe concepts which otherwise can be unevenly applied at the discretion of Regional audit teams. In fact, this action ignores the work output of Project 2010-17 "Definition of the Bulk Electric System" which was carefully crafted by the entire industry in response to FERC Docket RR09-6-000 - which was issued to eliminate exactly these kinds of ambiguities. **Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.** 2. What could possibly be a technical justification for including generators below that included in the Applicability Section. Without this in the Standard, it leaves

Organization	Yes or No	Question 5 Comment
		it open to whatever the PC is inlinded to do. If you have a "catch all" requirement, you need to have a specific set of technical requirements to limit the PC's discretion. **The reference to Planning Coordinator has been changed to Transmission Planner to be consistent with the Applicability section of the standard. The technical justification for a request is described in a footnote reference in the standard (see section 4.2.4) – in summary, the TP must demonstrate that the simulated unit or plant response does not match the measured unit or plant response.** 3. Registered Entities below the individual unit thresholds of 100MVA, 75MVA, and 50MVA do not need to be modeled unless there is technical justification. This is a significant burden on small generators. Small generators should only be required to provide model verification where the PC can show justification through a set of criteria. **The SDT believes that smaller units that meet NERC registry criteria connected to BES system can have a significant role in the stable operation of the grid – especially when in aggregate they meet or exceed the plant thresholds in the standard.**
Response: Thank you for your comment. Please see responses above.		
We Energies		a. In Section A3. reference is made to Bulk Electric System (BES) reliability. Then, in Section A4, there are repeated references to the "bulk power system" (BPS). Please clarify the distinction, and why the standard needs to refer to both the BES and the BPS. We believe all references should be to the BES. The use of "bulk power system" could possibly lead to the inclusion of generating units in the Applicability which are not connected to the BES, and should not be subject to this standard. **Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.**

Organization	Yes or No	Question 5 Comment
		b. In Requirement R1, instead of the TP providing "instructions", the standard should require the TP to simply "provide" the model data and the list of acceptable models, block diagrams, etc, to the GO upon request. The TP already has the expertise with these models and the dynamics software applications, and has easy access to the necessary information. Since the Generator Owners in most cases will not have access to the dynamics software and associated libraries, it would be more efficient to have the Transmission Planner provide the information (list of acceptable models, block diagrams/data, and existing in-use model data) instead of instructing the Generator Owner how to obtain it. **The software manufacturers have indicated that they will make accommodations so that generator owners without software licenses can receive the block diagrams and data sheets. Transmission Planners ordinarily have license agreements that do not permit them to provide the block diagrams and data sheets directly to the generator owner.** c. In Requirement R2.2, the GO is responsible to provide a verified aggregate model for multiple generating units rated less than 20 MVA. This will be an unreasonable burden on the GO, which typically does not have the modeling experience or the need to develop these equivalent models. The requirement should be more flexible to allow the GO the option to provide the same unit-specific data that is required for units rated 20 MVA or higher, or else to make the requirement applicable to both the GO and TP to allow them to work together to develop a suitable aggregate model. **Requirement R2 Part 2.2 has been re-worded and merged into Part 2.1. The new verbiage makes it clear that the entity performing the model verification has flexibility regarding if the model should be represented by individual unit or plant aggregate models or any combination therein as dictated by the specific situation.** **The genesis of this language around aggregated models was to address Variable Energy Resources (wind and large PV solar plants) where the standard practice is to use a single aggregated generator and collector model to represent all wind turbines or solar inverters in a plant with like technology. Aggregated models for**

Organization	Yes or No	Question 5 Comment
		renewable energy plants are available either from the OEM or via WECC's generic models and there shouldn't be an issue obtaining at least one of them. d. In R2.1.1, the GO is required to provide documentation that the generator model response matches the recorded response for a voltage excursion. Since the GO often does not have the capability to run dynamic studies, how will it obtain the "model response" for comparing to the recorded response? We suggest that this requirement be modified to require that the GO "provide the recorded response for a voltage excursion". As presently written, R2.1.1. can only be required of the TP. **The SDT has assigned responsibility for model verification to the Generator Owner and has received support for this proposal from the vast majority of industry. Generator Owners have access to the equipment, along with access to the equipment's Original Equipment Manufacturer for assistance with technical issues. Historically, the Transmission Planner and Generator Owner entities used to work for the same company, but in today's functional model environment, Transmission Planners could easily work for a different company than the generation entity. As such, the stated access advantages for the generation entity do not transfer to the Transmission Planner. The draft standard does not require the generator entity to perform dynamic simulations to determine Bulk Electric System limits. The generator entity is responsible for ensuring that the excitation system model response matches the response from a recorded voltage excursion. This can be accomplished through software that is much simpler than full dynamic simulation software utilized by Transmission Planners for assessing BES limits. Finally, agreements between the Transmission Planner and the Generator Owner can be arranged for the Transmission Planning entity to perform portions or all of the model verification process however responsibility for model verification remains with the Generator Owner.** Further thought and guidance needs to be given to this matter, as well as the availability and type of recording equipment needed to capture the voltage data as required in R2.1.1. There needs to be a recognition that the Transmission Planner

Organization	Yes or No	Question 5 Comment
		and Generator Owner will need to work cooperatively on this. The goal is good, but this standard is not nearly developed enough to be a useful standard. **Recording equipment needed to capture voltage data is widely available. The SDT does recognize that expertise in performing model verification is limited, and that entities will need time to either hire consultants to perform the verification or develop the expertise in house – thus the staged ten year Implementation Plan.**
Response: Thank you for your comment. Please see responses above.		
PPL Electric Utilities and PPL Supply NERC Registered Organizations		a. Independent generators provide model data to the TP/TOP and TO, who then run their models, but we do not ourselves have means of running dynamic models or representing within the model the system we connect-to. **The draft standard does not require the generator entity to perform dynamic simulations to determine Bulk Electric System limits. The generator entity is responsible for ensuring that the excitation system model response matches the response from a recorded voltage excursion. This can be accomplished through software that is much simpler than full dynamic simulation software utilized by Transmission Planners for assessing BES limits.** R2.1 1 should require the TP, not GOs, to run models and develop the referenced documentation (or, if the result is not suitable, open a dialogue per R3). The same comment applies for R2.2. **The SDT has assigned responsibility for model verification to the Generator Owner and has received support for this proposal from the vast majority of industry. Generator Owners have access to the equipment, along with access to the equipment's Original Equipment Manufacturer for assistance with technical issues. Historically, the Transmission Planner and Generator Owner entities used to work for the same company, but in today's functional model environment, Transmission Planners could easily work for a different company than the generation entity. As such, the stated access advantages for the generation entity do not transfer to the**

Organization	Yes or No	Question 5 Comment
		Transmission Planner. Finally, agreements between the Transmission Planner and the Generator Owner can be arranged for the Transmission Planning entity to perform portions or all of the model verification process however responsibility for model verification remains with the Generator Owner. b. There is presently no definition of the voltage excursion magnitude and intensity or the recording instrumentation sampling rate required for a valid verification event, nor are there any specifics regarding how closely the model must match the recorded response. **The SDT consciously avoided definitions of how tests are performed as well as quality of match between model and test to avoid risk of being over-prescriptive and too restrictive. The focus is solely on "what" is required, not "how" it's done. Ultimately, the Generator Owner and their testing and model validation entities are left to determine the appropriate tests and responses to validate models against, as well as determining how well the model represents the as-installed equipment.** The references in MOD-026 provide guidance but not necessarily NERC pass/fail criteria, especially since Transmission Planners may differ in their preferences. Perceived shortcomings in these respects would presumably trigger the Transmission Planner expression of concern described in R3, but it would be better to establish the rules up-front rather than addressing the matter only after a GO has attempted to comply with MOD-026. It was stated in the 7/29/11 webinar that a signal-to-noise ratio of at least 5:1 is needed for a meaningful validation, but this criterion is not included in the draft standard. **Again, the focus is solely on "what" is required, not "how" it's done. Ultimately, the Generator Owner and their testing and model validation entities are left to determine the appropriate tests and responses to validate models against, as well as determining how well the model represents the as-installed equipment.** c. We suggest replacing "rotational inertia" in R2.1.3 with "inertia constant (H)," the

Organization	Yes or No	Question 5 Comment
		rotational inertia divided by MVA rating, since this is the parameter of interest for stability studies. **In mentioning the rotational inertia, the SDT is providing examples of the types of data included to help understanding, and did not intend to specify the base that should be used in providing the data. The standards attempt to specify what is required, and hence do not provide the details regarding the data to be provided. However, for clarity, the term "inertia" in sub part 2.1.3. was modified to "total rotational inertia" as some industry commenters expressed concern that reference to "inertia" only would lead to submittal of an inertia constant reflective only of the generator, as opposed to all of the mass attached to the shaft.** d. The 4/6/10-year periods specified in paras. 5.1.1-5.1.4 and 5.2.1-5.2.4 on pp. 3-4 of MOD-026-1 should provide for existing plants enough time to catch a disturbance of sufficient magnitude for verification purposes; but the one-year allowance in row 3 on p.15 for plants that are new or have replaced controls equipment may prove inadequate, especially since (per comment 5b above) we don't currently know what sort of transient is needed. At least a four-year window should be granted for the initial verification. It is also unclear how one decides up-front the applicability of this standard to a new facility. The past-years test of para. 4.2 cannot be used; and a unit anticipated to have less than a 5% capacity factor may prove otherwise depending on market conditions or other factors. In any event the one-year verification limit for new and modified units is inadequate if it takes longer than this amount of time just to determine whether or not MOD-026-1 is applicable. **The SDT believes that a new excitation control system will be tested during commissioning and the test data will be adequate to comply with this standard. Whether or not a new unit may have a capacity factor of greater than 5%, it should still be commissioned with initial testing of the excitation control system. If additional time is needed to create a model from the test data, the SDT believes that 1 year is adequate. The standard requires each new unit to be modeled within one year.**

Organization	Yes or No	Question 5 Comment
		e. The use of the undefined term "technically justified request" in R5 is unclear. Does this term apply only if a model fails to meet the requirements of R6.1-R6.3, or can there be other reasons? Further, the 90 day time period should not begin until both parties fully understand the "technically justified request." **The technical justification for a request is described in Footnote 2 of the current draft of the standard. The technical justification request in Requirement R5 is intended to perform a model review for any unit/plant not included in the applicability section of the standard. The 90 day grace period in Requirement R5 is intended for the Generator Owner to perform a review and submit a written response to Transmission Planner's request. The 90 days grace period is not intended for Generator Owner to perform model verification.** f. The means by which a walk-down would lead to identification of model parameters in the second bull-dot of R.5.2 is not understood. **The text has been modified and the expression "walk down" was replaced by "on-site review" of the equipment.**
Response: Thank you for your comment. Please see responses above.		
Independent Electricity System Operator		a. Requirement R2.1: We continue to disagree with the phrase "models acceptable to the Transmission Planners" as it is a potential source of dispute between the TP and the GO. Requirement R1 already asks the TP to provide instructions and model data to its requesting GO but makes no reference to "acceptability". To avoid potential disputes, we suggest that R2.1 be reworded to:R2.1. Perform verifications using one or more models provided by the Transmission Planner in R1, that include(s) the following information: **In the current draft, bullet one in Requirement R1 makes provisions for the Transmission Planner to provide instructions for the Generator Owner to acquire models that are acceptable to the Transmission Planner. The SDT believes that the subsequent phrase in Requirement 2 which reads "perform verification using one**

Organization	Yes or No	Question 5 Comment
		or more models acceptable to the Transmission Planner" sufficiently specifies the link to Requirement R1 bullet one. b. We continue to disagree with Parts R6.1 to R6.3 which set the criteria for usable model. The stipulated criteria may not be accomplished even if the GO provides an accurate excitation control system and plant volt/var control function model, especially if such devices are new for which there are no previous simulations to benchmark with. **The SDT believes that excitation systems and other closed-loop control systems in a power plant (barred some mal-function or failure) are commissioned to provide stable and properly damped response. Thus, validated simulation models should exhibit a similar response and that can be easily assessed using simulations as those described in Part 6.1 to Part 6.3. On the other hand, a model that does not exhibit a stable and properly damped response to these simulations described in Part 6.1 to Part 6.3 is probably not representing the actual behavior of the equipment and this discrepancy should be addressed before the model is accepted and deemed usable.** A computer model may fail to initialize due to reasons other than inaccuracy in the submitted excitation control system and plant volt/var control function model itself, and a no-disturbance simulation may not result in the excitation control system and plant volt/var control system model exhibiting positive damping due to other system parameters. System damping is affected by many other dynamic performance contributors such as other generators, system topology, power flow levels, voltage levels, excitation system and power system stabilizer settings, etc. **The models can be tested, as described in Part 6.1 to Part 6.3, based on a machine vs. infinite bus simulation model. As such, the influence of other models is removed. On the other hand, if a simulation model fails to initialize, it might indicate issues with limits and/or per unit scales and these issues should be addressed before the model can be considered approved or usable.**

Organization	Yes or No	Question 5 Comment
		In short, having an accurate excitation control system and plant volt/var control function model does not necessary guarantee or equate to meeting the conditions stipulated in the three parts. We suggest this requirement be removed. **The Part 6.1 to Part 6.3 are related to the usability of the models by the end-users (entities carrying out system simulations) and are not exactly related to the validity of the models. The SDT believes that the models should be not only valid models, but also usable models.**
Response: Thank you for your comment. Please see responses above.		
Duke Energy		o R2, 2.1.3 - Please revise to specify total inertia. Total unit inertia should be given to include all coupled rotating elements. The way this is currently worded, it could lead generators to only provide the generator H values. **The SDT has modified the term to include "total" rotational inertia as suggested.** o R2, 2.2 - Insert the phrase "or individual unit" after the word "aggregate". **Requirement R2 Part 2.2 has been re-worded and merged into Part 2.1. The new verbiage makes it clear that the entity performing the model verification has flexibility regarding if the model should be represented by individual unit or plant aggregate models or any combination therein as dictated by the specific situation.** o Page 15, Equivalent applicable unit - Identically designed generation units are identical in control response, independent of site location. New techniques for validation eliminate the impact of the grid on the validation efforts. Thus, credit for sister unit validations should be available independent of the location of a unit or connected voltage. **The SDT notes the general agreement among industry with using the proxy unit approach. The SDT respectfully maintains that the "same physical location" requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during**

Organization	Yes or No	Question 5 Comment
		a single site review). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g. requirement for PSS in-service). To ensure all GO/GOP equipment meets standard intent, the SDT maintains the "same physical location" requirement is necessary.
Response: Thank you for your comment. Please see responses above.		
American Transmission Company, LLC		ATC recommends that the SDT give consideration to the following:1. In Requirements, R1, bullet 2 - change the wording to be more similar to bullet 1, "obtain model library block diagrams and/or data sheets that are acceptable to the Transmission Planner for use in dynamic simulations". Software manufacturer model library block diagrams and data sheets are usually proprietary and most Generator Owners do not own the license to receive them. As in the more general wording bullet 1, requiring instructions to simply obtain acceptable diagrams and data sheets, allows the Transmission Planner to provide instructions for obtaining either public (IEEE standard) or proprietary diagrams and data sheets depending on the Generator Owner licenses or lack of licenses. **The standard drafting team has revised the wording of Requirement R1 bullet two. Also, it should be noted that the software manufacturers have indicated that they will make accommodations so that generator owners without software licenses can receive the block diagrams and data sheets. Transmission planners ordinarily have license agreements that do not permit them to provide the block diagrams and data sheets directly to the generator owner.** 2. In Event Triggering Verification Table, Item 6, Cell 1 - fix typographical error of ". . . system event did not "did not" match . . ." **The typographical error has been corrected.**

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. Please see responses above.		
ERCOT		1: Requirement R2 and voltage ride through curve in the PRC-024 Attachment 2 are applicable to the voltage at point of interconnection to the Bulk Electric System (BES). However, in requirement R2.1 "When operating within 95 percent to 105 percent of rated generator terminal voltage and during the transmission system operating conditions defined in PRC-024 Attachment 2, with the following clarifications:" The clarification is needed for R2.1 that describes how the generator terminal voltage will affect the applicability to this requirement. **The clarification phrase has been removed and Requirement R2 has been restructured to provide more clarity around when it is acceptable for the unit to trip.** 2: In the attachment 1 and attachment 2, it is not clear if a unit can be allowed to trip instantaneously under extreme high voltage or high/low frequency occurred during and post disturbance period. For example, the physical limitation requires a wind farm to trip the turbine instantaneously when voltage is above 1.25 pu. If there is a short duration of overvoltage, 1.3pu for 0.15 second, during and post disturbance period that cause the wind farm trip the turbines, does this wind farm violate the requirement as stated in attachment 2 that requires the wind farm to remain in service for 0.2 second when voltage is above 1.2 pu? **Tripping of a unit or plant is allowed anywhere outside of the curves. The table in attachment 2 has been revised and now has an entry that allows for instantaneous tripping when the voltage is greater than or equal to 1.20 pu.**
Response: Thank you for your comment. Please see responses above.		
Cowltiz PUD		Cowlitz PUD respectfully disagrees with the use of the statutory term bulk[-]power system in the applicability section of any reliability standard. This term is not

Organization	Yes or No	Question 5 Comment
		adequately defined to be used anywhere excepting arguments as to whether a proposed standard falls within the jurisdiction of the Federal Power Act of 2005. Use of the statutory term will hamper any future efforts to revise the Statement of Compliance Registry Criteria. The Bulk Electric System is a subset of the bulk-power system. If the intent of the SDT is to include any generation of stated MVA name plate capacity connected to a "transmission system" operated at an undefined voltage, the result will be to defeat work being done to technically justify exclusion of certain bulk-power system facilities which have no substantial impact on Reliability. If however, the intent of the SDT is to follow the Statement of Compliance Registry Criteria and imply that the "BPS" is equal to the BES, it is preferable to specify generation connection voltage than use BPS. Cowlitz agrees that non-BES generation may need to be included in this standard's applicability section (as users of the BES), however specific generation that a particular GO may own which by itself would not have required registration of the entity should not be inadvertently included in the applicability of this standard.
Response: We appreciate your thoughtful comments. Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.		
FirstEnergy Corp		FirstEnergy would like to make the following comments on this standard: 1) Under the Applicability section 4.2.1.2, the use if the term "common bus" should be clarified as either the low-side or high-side of the GSU. **The SDT team believes that the consistent use of the term "directly connected to the Bulk Electric System" in the current draft of the standard makes it clear that it is referring to the high side of GSUs of 115 kV or greater.** 2) Footnote 1a on Page 2, says that "... the generator excitation control system includes the generator, exciter, voltage regulator and power system stabilizer."

Organization	Yes or No	Question 5 Comment
		While we understand that the excitation system supplies the generator field, there is a separate Model for the Generator (typically GENROU). We suggest omitting the word generator from the footnote to avoid confusion. **The SDT believes that the generator is an integral part of the voltage/reactive power control loop and thus an essential part to the validation of the excitation control system response. As such, there is no separate Standard regarding the validation of the generator model, so the SDT believes there is no conflict or confusion regarding the validation of the generator model.** 3) Suggest rewording 2.1 to begin with, "Provide models acceptable to the Transmission Planner, including verified parameters ...", rather than "Perform verifications ...". The GO provides information on applicable models as well as the parameters. The TP actually runs the models to determine system impact. **The SDT has assigned responsibility for model verification to the Generator Owner and has received support for this proposal from the vast majority of industry. Generator Owners have access to the equipment, along with access to the equipment's Original Equipment Manufacturer for assistance with technical issues. Historically, the Transmission Planner and Generator Owner entities used to work for the same company, but in today's functional model environment, Transmission Planners could easily work for a different company than the generation entity. As such, the stated access advantages for the generation entity do not transfer to the Transmission Planner.** 4) Requirement 2.1.1 requires "Documentation demonstrating the applicable unit's model response matches the recorded response for a voltage excursion at the applicable unit's point of interconnections from either a staged test or a measured system disturbance. O Please define or qualify the term "matches". This is a subjective term, subject to interpretation of results; i.e., what % error is considered "matching". **The SDT consciously avoided definitions of how tests are performed as well as**

Organization	Yes or No	Question 5 Comment
		quality of match between model and test to avoid risk of being over-prescriptive and too restrictive. The focus is solely on "what" is required, not "how" it's done. Ultimately, the Generator Owner and their testing and model validation entities are left to determine the appropriate tests and responses to validate models against, as well as determining how well the model represents the as-installed equipment. oRefers to recorded response "... at the applicable unit's point of interconnection ...". This should be reworded to "at generator terminals". An excitation system controls to the generator terminals since this is where Voltage and Current inputs to the AVR originate. Further, this is where measurements are taken during dynamic testing. **Specific reference to point of connection is removed from Requirement R 2, Part 2.1.1. Language has been modified to: "Documentation demonstrating the applicable unit's model response matches the recorded response for a voltage excursion from either a staged test or a measured system disturbance."** o"a measured system disturbance" is not practical for a GO, and should be eliminated. DME is owned by the TO, and do not have access to results of disturbances. **The intent of this language is to allow GO's to use recorded data (if they have it) from a known system event as a means to validate an exciter or volt/var control model against. Ultimately, the usability of this or any data to validate a model against is at the discretion of the GO and their testing and model validation entities.**
Response: Thank you for your comment. Please see responses above.		
American Electric Power		For section 4.2 we suggest the term "bulk power system" be replaced with "Bulk Electric System". BES is currently being defined, while bulk power system currently does not have a definition and thus is ambiguous.

Organization	Yes or No	Question 5 Comment
		Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term. In the second bullet of 4.2.1.2, one of the words "comprised" or "consisting" needs to be removed as they are redundant. Also, we are confused by the bullets in 4.2.1.2 which should be re-worded to clarify the intent. For example, would diesel generators at a larger facility be in scope of this requirement? Furthermore, the qualifier between the two bullets should be "or" rather than "and". **The section was re-written to provide clarity and in the process, the word "comprised" was deleted. With the new language, the qualifier between the bullets is correct.** For the effective date, we recommend not mixing years and quarters. Instead, we recommend that the total number of quarters be used, otherwise it is unclear if the effective date is the quarter following the year or the quarter at the end of that year. **The effective date is specified using standard language that is well known and understood.** Throughout the standard, "generator excitation control system and plant volt/var control function model" should have an "or" rather than an "and". **The SDT implemented your suggestion.** The second footnote in requirement 4 could be interpreted to be all-inclusive. Please check the numbering of all footnotes and the pages that those footnotes reference. References should only be made to footnotes on the same page as the referring number. **The SDT has made the aforementioned corrections.**
Response: Thank you for your comment. Please see responses above.		
Indiana Municipal Power		IMPA believes that the reference of "bulk power system" should be replaced with

Organization	Yes or No	Question 5 Comment
Agency		Bulk Electric System throughout the standard. Bulk power system is used in the Compliance Registry, but it is not a NERC defined term. FERC even agrees that bulk power system goes beyond the Bulk Electric System (FERC Order 693). **Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.** IMPA is troubled by the requirement in R2.1.1 that requires a voltage excursion from a staged test or a measured system disturbance. Are there an ample supply of contractors or consultants that can perform such a test? What is the risk to a unit to perform the staged test? **A staged test to obtain data to verify excitation control system models does not typically involve an actual BES voltage excursion. A stage test typically involves injecting a step change signal into the unit's voltage regulator – which makes the voltage regulator "think" that a voltage excursion has occurred. Usually a laptop PC can be used to record the resulting staged testing data. There has been ample experience in industry with safely and effectively using a staged test.**
Response: Thank you for your comment. Please see responses above.		
Los Angeles Department of Water and Power		LADWP supports the language under Attachment 1, "Consideration for Early Compliance".
Response: Response: Thank you for your comment.		
Manitoba Hydro		Manitoba Hydro is voting negative for the following reasons: 1 - Implementation time frames - the implementation plans/effective dates for the standards MOD-025, MOD-026, MOD-027, and PRC-019 in Project 2007-09 should be the same to reduce unnecessary outages and to maximize the productivity of site visits. Manitoba Hydro suggests that the implementation plan for MOD-026 be applied to MOD-025, MOD-027 and PRC-019.

Organization	Yes or No	Question 5 Comment
		MOD-024 and MOD-025 have now been combined. The verification of steady state MW and MVAR capabilities would be accomplished by test which is distinctly different than the activities required for verification of excitation control systems. Also, the verification of steady state MW and MVAR capabilities would be accomplished without taking the unit out of service. Personnel involved in steady state MW and MVAR capabilities will almost certainly be different than personnel involved in the verification of excitation control systems. Also, the verification of excitation control systems per the current draft of MOD-026 will almost always be ten years, whereas the periodicity of steady state MW and MVAR capabilities per the current draft of MOD-025 is only five years. MOD-012 and MOD-013 are simply data submittal standards as opposed to data verification standards. Also, the effective and implementation dates for the current drafts of MOD-026 and MOD-027 (dynamic model verification standards) are effectively the same. 2 - R5 ‘walk down’ - the requirement of a ‘walk down’ of equipment in R5 is unclear. Manitoba Hydro suggests that the wording be revised to ‘based on an onsite review of the equipment. **The text has been modified and the expression “walk down” was replaced by “on-site review” of the equipment.** ’3 - Data Retention - The data retention requirements are too uncertain for two reasons. First, the requirement to “provide other evidence” if the evidence retention period specified is shorter than the time since the last audit introduces uncertainty because a responsible entity has no means of knowing if or when an audit may occur of the relevant standard. Secondly, it is unclear what ‘other evidence’, besides the specified evidence in the Measures, an entity may be asked to provide to demonstrate it was compliant for the full time period since their last audit. **Entities need to be able to demonstrate that they are compliant with the standard, regardless of the date of the last audit. The drafting team used the boilerplate language endorsed by the Standards Committee.**

Organization	Yes or No	Question 5 Comment
		Manitoba Hydro also suggests that synchronous condensers be included in MOD-026. **The GVSDT asked stakeholders if they believed that synchronous condensers should be applicable under MOD-026. The majority of commenters believe that synchronous condensers should not be included in MOD-026. Synchronous condensers are not currently addressed in the NERC Registry Criteria. On an MVA capacity basis, the penetration of synchronous condensers in North America is extremely low, with many units owned by Transmission Owners. As such, the peer review draft requirements would not make sense. The SDT decided that, with the current structure of the Compliance Registry Criteria, if there is a need to develop a reliability standard to model the expected behavior of dynamic voltage devices typically owned by Transmission entities, then a more appropriate strategy is to include synchronous condensers along with other Transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) into a separate SAR. The GVSDT will closely monitor BES SDT efforts to define BES and the correlation of BES elements with the ERO Statement of Compliance Registry Criteria, and make appropriate adjustment as necessary to the Applicability of MOD-026-1 regarding the treatment of synchronous condensers.**
Response: Thank you for your comment. Please see responses above.		
Entergy Services		MOD-026-1 R2.1.1 is:2.1.1. Documentation demonstrating the applicable unit’s model response matches the recorded response for a voltage excursion at the applicable unit’s POINT OF INTERCONNECTION from either a staged test or a measured system disturbance. We recommend the POINT OF INTERCONNECTION be changed to GENERATOR TERMINALS.
Response: Thank you for your comment. Specific reference to point of connection is removed from Requirement R2 Part 2.1.1. Language has been modified to: “Documentation demonstrating the applicable unit’s model response matches the recorded response for a voltage excursion from either a staged test or a measured system disturbance.”		

Organization	Yes or No	Question 5 Comment
Progress Energy		Our AFFIRMATIVE vote is conditional upon the "Clean" version being voted on. There are major differences between the Red-line and clean version in Section 5 "Effective Date". The Clean version 5.1.3 requires 50 % where as Red-line version has 100 %
Response: Thank you for your comment. The clean version is the appropriate version to reference if there are any differences between the clean and red line versions.		
MRO NSRF		Please give consideration to the following suggestions from the MRO NSRF: 1. In Requirements, R1, bullet 2 - change the wording to be more similar to bullet 1, “obtain model library block diagrams and/or data sheets that are acceptable to the Transmission Planner for use in dynamic simulations”. Software manufacturer model library block diagrams and data sheets are usually proprietary and most Generator Owners do not own the license to receive them. As in the more general wording bullet 1, requiring instructions to simply obtain acceptable diagrams and data sheets allows the Transmission Planner to provide instructions for obtaining either public (IEEE standard) or proprietary diagrams and data sheets depending on the Generator Owner licenses or lack of licenses. **The standard drafting team has revised the wording of Requirement R1 bullet two. Also, it should be noted that the software manufacturers have indicated that they will make accommodations so that generator owners without software licenses can receive the block diagrams and data sheets. Transmission Planners ordinarily have license agreements that do not permit them to provide the block diagrams and data sheets directly to the generator owner.** 2. In Event Triggering Verification Table, Item 6, Cell 1 - fix typographical error of “. . . system event did not did not match . . .” **The typographical error has been corrected.** 3. Please restructure requirements and evidence to allow for posted instructions and model data to meet compliance for appropriate requirements such as R1,R2, etc...

Organization	Yes or No	Question 5 Comment
		Response: The SDT apologizes but we could not determine your question. 4. In the second bullet item under Applicability Section 4.2.1.2, recommend the drafting team remove the word "consisting" and add the word "solely" to avoid confusion. Section 4.2.1.2 would instead read "Each generating plant / Facility comprised consisting solely of ...". **Section 4.2.2 of the standard applicability has been revised and the word "consisting" has been deleted.** 5. Recommend the capacity factor test in Applicability Section 4.2 be revised to state: "Applicable units or plants with an average capacity factor greater than 5 percent ..." As currently drafted, it is unclear as to whether all units, applicable or not, are included in the calculation of the Capacity Factor (CF). In cases where an entity has a plant with one 60 MVA unit and three 15 MVA units, the units less than 20 MVA would not be applicable per the criteria in MOD-026-1. However, would all units still be factored into the CF calculation? **The capacity factor statement in section 4.2 is the first qualifying statement for applicability of all units. Any unit that does not meet the capacity factor qualifier is not included in the standard. Any unit that does meet the capacity factor qualifier is then subjected to the next qualifiers of MVA rating and connection to the BES. The SDT does not believe that the use of the word "applicable" in the capacity factor qualifier would clarify the standard.** 6. Requirement R6.3 specifies "a disturbance simulation results in .... exhibiting positive damping". Guidance is needed as to what is considered acceptable positive damping. **The SDT believes that excitation systems and other closed-loop control systems in a power plant (barred some mal-function or failure) are commissioned to provide stable and properly damped response. Thus, validated simulation models should exhibit a similar response and that can be easily assessed using simulations as those described in Part 6.1 to Part 6.3. On the other hand, a model that does not**

Organization	Yes or No	Question 5 Comment
		exhibit a stable and properly damped response to these simulations described in Part 6.1 to Part 6.3 is probably not representing the actual behavior of the equipment and this discrepancy should be addressed before the model is accepted and deemed usable. It should be noted that Part 6.1 to Part 6.3 are related to the usability of these validated models in system studies, not exactly with the validation. 7. R6 has two periods at the end of the paragraph just before [Violation Risk Factor ...] **This has been corrected in this revision.** 8. In the applicability section 4.2, the undefined term bulk power system is used. To avoid confusion regarding the applicability, it is recommended the defined term Bulk Electric System be used. **Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.**
Response: Thank you for your comment. Please see responses above.		
ReliabilityFirst		ReliabilityFirst abstains on the MOD-026-1 ballot and offers the following comments for consideration: 1. Facilities a. What is the rationale/justification for the size qualification for applicable units (i.e. greater than 100 MVA)? ReliabilityFirst believes all generating units connected to the BES and referenced in the NERC Statement of Compliance Registry Criteria should be included within this standard. **As discussed in the Comment Form with the first posting of the draft MOD-026 standard, the SDT considered the extent of the facilities to be verified and how to reflect this in the "applicability" of this proposed standard. As a basis, the SDT recognized that the excitation system models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality**

Organization	Yes or No	Question 5 Comment
		dynamics database. However, as confirmed through the Field Test, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the exciter models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA thresholds corresponding to 80% of connected MVA or greater for each Interconnection are proposed. The SDT further believes that a minimum unit interconnection of >100 kV, consistent with the Compliance Registry Guidelines, is appropriate. Finally, the SDT believes that the standard should apply to units with a capacity factor such that they are on-line 1000 hours or greater a year. The SDT believes that these three applicability thresholds will result in substantial accuracy improvement to the excitation models and associated Reliability based limits determined by dynamic simulations, while not unduly mandating costly and time consuming verification efforts. The SDT asked a specific question on the Comment Form regarding the proposed applicability, and the response to the question reflected Industry concurrence with this approach. 2. Requirement R1 a. For the purposes of NERC standards, "bullets points" are to be considered "OR" statement. ReliabilityFirst believes all the "bullets points" in R1 are required and should renumbered into sub-parts (i.e. 1.1, 1.2, 1.3) **The SDT believes that these bullet points are "OR" statements, at least to the sense that a Generation Owner might not have requested all three items listed in the bullets. The requirement is meant to be that the TP should provide the information requested by the GO.** 3. Requirement R5a. ReliabilityFirst is unclear on the meaning of the term "walk down of the equipment" in the second bullet? ReliabilityFirst request further clarification of the term "walk down of the equipment?"

Organization	Yes or No	Question 5 Comment
		The text has been modified and the expression "walk down" was replaced by "on-site review" of the equipment. 4. Requirement R6a. ReliabilityFirst requests further clarification on the term "initializes" as referenced in Subpart 6.1. Is this in the context of excitation control system and plant volt/var control function model initialization within a PSSE application? **The SDT wants to reiterate that model usability is a different issue than model validation. The objective of Part 6.1 to Part 6.3 is to assess the usability of the models in system simulations (e.g. PSS/E, PSLF or whatever simulation tool being used). The tests listed in these requirements are expected to be typically performed when a new model is incorporated to the simulation database.** 5. Section G. References. ReliabilityFirst recommends removing the references in Reference Section G and place it into a reference type document. Even though this good information, it is not needed in a Reliability Standard. **The SDT believes the references are useful to some users and should be provided in the most helpful location. In some cases, references are included in a NERC standard instead of moving them to a separate document.** 6. VSL Requirement R2a. Requirement R2 contains a sub-part 2.2 which is not mentioned in the corresponding Violation Severity Level (VSL). ReliabilityFirst recommends including a VSL covering Subpart 2.2. Here is an example of a "lower" VSL: "For plants that are comprised of units that have a gross nameplate rating of less than 20 MVA in Requirement R2, Subpart 2.2, the Generator provided the Transmission Planner verified models, using plant aggregate model(s), that omitted one of the six Parts identified in Requirement R2, Subparts 2.1.1 through 2.1.6." **Requirement R2, Part 2.2 has been re-worded and merged into Part 2.1. The new verbiage makes it clear that the entity performing the model verification has flexibility regarding if the model should be represented by individual unit or**

Organization	Yes or No	Question 5 Comment
		plant aggregate models or any combination therein as dictated by the specific situation. A VSL does exist in the current draft for Part 2.1. 7. VSL Requirement R5 a. The VSL for "High" and "Severe" mention Subparts 5.2 and 5.3 though there are no associated subparts referenced in Requirement R5 (there are only 2 bullet points). ReliabilityFirst recommends removing the references to Subparts 5.2 and 5.3. **Based on your comment, the SDT has revised the verbiage for the High VSL to not include any references to the sub bullets in Requirement R5, and revised the verbiage for the Severe VSL to include " OR The Generator Owner's written response failed to include one of the sub bullets of Requirement R5"** 8. VSL Requirement R6a. R6 requires the Transmission Planners to "...notify the Generator Owner within 90 calendar days... ", while the corresponding VSL states "The Transmission Planner provided a written response to the Generator Owner indicating..." **The reference to the required time frame in the VSL is included.** Based on the FERC Guideline #3 "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement," ReliabilityFirst recommends the following as an example of the "Lower" VSL: "The Transmission Planner notified the Generator Owner indicating whether the model is useable or not useable; including a technical description if the model is not useable, more than 90 calendar days but less than 120 calendar days of receiving verified model information. (R6)" **The SDT believes that all of the relevant information is addressed in an acceptable format in the current version of the VSL.**
Response: Thank you for your comment. Please see responses above.		
Florida Municipal Power Agency		The applicability refers to the "bulk power system", e.g., "4.2.1.1 Individual generating unit greater than 100 MVA (gross nameplate rating) directly connected to

Organization	Yes or No	Question 5 Comment
		the bulk power system". The term "bulk-power system" should not be used in the standards as it is ambiguous and should be replaced with "Bulk Electric System". We do not understand how the Applicability of 4.2.1.2 means. **Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.** We suggest making the language clearer.R2.1.1 should only apply if a system disturbance actually happens and should not require a staged test. A staged test could threaten the reliability of the BES more than inaccuracy of an excitation system model. **A staged test to obtain data to verify excitation control system models does not typically involve an actual BES voltage excursion. A staged test typically involves injecting a step change signal into the unit's voltage regulator – which makes the voltage regulator "think" that a voltage excursion has occurred. Usually a laptop PC can be used to record the resulting staged testing data. There has been ample experience in industry with safely and effectively using a staged test.** R4 should specifically exclude temporary changes, e.g., generator AVR settings are often changed when the unit is started or shut-down, if the AVR is planned out of service, etc., we believe the intent of the standard is only to communicate more permanent changes and not temporary changes. **Changes in operating mode (auto/manual, PSS on/off, etc.) do not trigger the need to provide a revised model or re-verification as described in Requirement 5. The following sentence has been added to Footnote 4 in the current draft of the standard to clarify the intent: "Automatic changes in settings that occur due to changes in operating mode do not apply to Requirement 5".** R5 is ambiguous. What is technically justified? Who gets to decide what is technically qualified? **The technical justification for a request is described in Footnote 2 of the current**

Organization	Yes or No	Question 5 Comment
		draft of the standard.
Response: Thank you for your comment. Please see responses above.		
City of Vero Beach		The applicability refers to the "bulk power system", e.g., "4.2.1.1 Individual generating unit greater than 100 MVA (gross nameplate rating) directly connected to the bulk power system". The term "bulk-power system" should not be used in the standards as it is ambiguous and should be replaced with "Bulk Electric System". We do not understand how the Applicability of 4.2.1.2 means. **Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.** We suggest making the language clearer.R2.1.1 should only apply if a system disturbance actually happens and should not require a staged test. A staged test could threaten the reliability of the BES more than inaccuracy of an excitation system model. **A staged test to obtain data to verify excitation control system models does not typically involve an actual BES voltage excursion. A staged test typically involves injecting a step change signal into the unit's voltage regulator – which makes the voltage regulator "think" that a voltage excursion has occurred. Usually a laptop PC can be used to record the resulting staged testing data. There has been ample experience in industry with safely and effectively using a staged test.** R4 should specifically exclude temporary changes, e.g., generator AVR settings are often changed when the unit is started or shut-down, if the AVR is planned out of service, etc., we believe the intent of the standard is only to communicate more permanent changes and not temporary changes. **Changes in operating mode (auto/manual, PSS on/off, etc.) do not trigger the need to provide a revised model or re-verification as described in Requirement 5. The following sentence has been added to Footnote 6 to clarify the intent: "Automatic changes in settings that occur due to changes in operating mode do not apply to**

Organization	Yes or No	Question 5 Comment
		Requirement R5". R5 is ambiguous. What is technically justified? Who gets to decide what is technically qualified? **The technical justification for a request is described in Footnote 2 of the current draft of the standard.**
Response: Thank you for your comment. Please see responses above.		
Dynegy		The division of responsibility (between GO and TP) in the task of 'verifying' the model should be revisited. Some GOs have neither the modeling expertise nor the software for this task. TPs typically have more experience running these types of models. We believe a more appropriate division of responsibility is to have the GO supply the field data from the response test and let the TP run and 'verify' the models. This would also eliminate the question of what constitutes a 'verified' model, i.e., how good is good enough.
Response: Thank you for your comment. The SDT considered who should be the owner of the model and asked Industry during the first posting. Generator Owners have access to the equipment, along with access to the equipment's Original Equipment Manufacturer for assistance with technical issues. Historically, the Transmission Planner and Generator Owner entities used to work for the same company, but in today's functional model environment, Transmission Planners could easily work for a different company than the generation entity. As such, the stated access advantages for the generation entity do not transfer to the Transmission Planner. For all of these reasons, the SDT believes that the Generator Owner is the appropriate entity to perform model verification activities. Finally, as the owner of the model, the peer review Requirement R3 clearly states that the Generator Owner has the final say for any technical discussions regarding the model. Finally, the Generator Owner could pursue entering an agreement with the Transmission Planner to perform portions or all of model verification. However, the Generator Owner would still be responsible from a compliance perspective.		
Western Electricity		The introduction to this comment form indicates that "The typographical errors in R2.1.1 language has been corrected to clearly state expectation that, "The unit or

Organization	Yes or No	Question 5 Comment
Coordinating Council		plant's model response matches the recorded response for a voltage excursion at the generator or plant point of Interconnection..." However, the versions posted for review (clean and redline) do not indicate that the "unit or plan's model..." They say the "applicable unit's model response matches..." There is no reference to plants in part 2.1.1
Response: Thank you for your comment. In the Applicability section 4.2 (Facilities), the first sentence reads "For the purpose of this standard, the following Facilities are considered...."applicable units" Units or plants that meet the following ....." . As such, references in the standard to "applicable units" includes units and plants. A reference to an "applicable unit" is included in part 2.1.1		
Austin Energy		The standard drafting team may consider adding the sentences in footnotes 2 & 3 directly to section 4.2 Facilities to avoid potentially unnecessary complexity. Also in section 4.2 Facilities, the term bulk power system (BPS), not BES is used. Would use of BES instead of BPS remove the need for footnote 2 without changing the overall intent of the SDT?
Response: We appreciate your thoughtful comments. Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term. The SDT also removed Footnote 2. The SDT believes that the standard is more readable by placing the information pertaining to capacity factor in the footnote.		
Consolidated Edison Co. of NY, Inc.		Use of terms Bulk Electric System (BES) in the purpose and bulk power system in the Applicability section should be reconciled. NERC is standardizing on the term Bulk Electric System (BES). **Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.**

Organization	Yes or No	Question 5 Comment
		Requirement 2: o R2.1.1: requires that model results must "match" results from field testing. This language implies that there is zero tolerance which is unreasonable. There should be some stipulated allowed tolerance band. We suggest that a tolerance is a specific value based on per unit. For example, the model and actual response shall match within a tolerance of .02 per unit of the buss voltage being controlled. **The draft standard states "what is required" but not "how to accomplish what is required". The SDT considered ways to quantify a method for evaluating how well the equipment's measured response matches the model's predicted response. However, since a generally accepted technique or criteria for making this quantitative assessment does not exist, the SDT believes that the peer review process incorporated into the standard will ensure model quality. The SDT believes all entities involved with the peer review process have common purpose to develop an accurate excitation control system model.** o The units "point of interconnection" is open to interpretation and could create compliance uncertainty. Almost all generator excitation systems control the generator terminal voltage (low side of the GSU) while the term "point of interconnection" may be interpreted as on the substation bus (high side of the GSU). A suggestion is use the following: at the buss controlled by the generator excitation system. **Specific reference to point of connection is removed from Requirement R2, Part 2.1.1. Language has been modified to: "Documentation demonstrating the applicable unit's model response matches the recorded response for a voltage excursion from either a staged test or a measured system disturbance."** The Applicability Section of the Standard, Section 4.2 permits exclusion of generators with a low capacity factor (< 5%). Why should the Standard allow an exemption for low capacity factor units? The objective of the Standard is to develop good excitation models for dynamics simulations, which are often conducted under high

Organization	Yes or No	Question 5 Comment
		load conditions. At higher loads, these lower capacity factor units are frequently needed and operating. Therefore the Standard should apply to even lower capacity factor units. **The increase in excitation control system model verification is expected to result in improved accuracy of stability based security assessments. The SDT does not believe un-verified data is necessarily inaccurate or that the overall stability of the system is sensitive to that data. The excitation information from the generating units with a 5% capacity factor or less, as provided per standards MOD-012 and MOD-013, is included in the models used to analyze the system under various conditions. Even if these low capacity factor generating units are verified, the accuracy of the simulation is not guaranteed because there are other significant assumptions involved in simulation results, such as load models. As such, the verified models do not provide absolute accuracy under operating conditions other than those conditions for which verification is performed.** Tables following Attachment 1: the purpose of these tables is not clear, they are not referenced in the Requirements. **The periodicity information included in Attachment 1 is referenced in Requirement 2, "...in accordance with the periodicity specified in MOD-026 Attachment 1". The attachment table format is being used because the SDT believes that it is the clearest way to present the periodicity information.** Note, there is an entire page of technical references included in the Standard (section G). It is not clear why this is necessary, as the references are described as "beyond the scope of this Standard". **The references are industry documents related to excitation systems. They are provided as a courtesy only because the SDT believes they will be helpful to some users. The referenced documents are not required reading nor are they required for compliance with the standard.**

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. Please see responses above.		
Northeast Power Coordinating Council		Use of the terms Bulk Electric System (BES) in the Purpose and bulk power system in the Facilities Section should be reconciled. NERC is standardizing on the term Bulk Electric System (BES). **Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.** In the Applicability Section under the Introduction, the bullets under 4.2.1.2 are unnecessary. The wording of 4.2.1.2 already covers what the bullets detail. **The SDT has refined section 4.2.1.2 of the Facilities section under** **Applicability to provide added clarity.** Regarding Requirement 2: o R2.1.1: requires that model results must "match" results from field testing. This language implies that there is zero tolerance which is unreasonable. There should be a stipulated allowable tolerance band. Suggest that a tolerance be a specific value based on per unit. For example, the model and actual response shall match within a tolerance of .02 per unit of the bus voltage being controlled. o R2.1.1: A unit's "point of interconnection" is open to interpretation and could create compliance uncertainty. Almost all generator excitation systems control the generator terminal voltage (low side of the GSU) while the term "point of interconnection" may be interpreted as on the substation bus (high side of the GSU). A suggestion is use the following: at the bus controlled by the generator excitation system. **Specific reference to point of interconnection is removed from Requirement R2 Part 2.1.1. Language has been modified to: "Documentation demonstrating the applicable unit's model response matches the recorded response for a voltage excursion from either a staged test or a measured system disturbance."**

Organization	Yes or No	Question 5 Comment
		Tables following Attachment 1: the purpose of these tables is not clear, they are not referenced in the Requirements. **The periodicity information included in Attachment 1 is referenced in Requirement 2, "...in accordance with the periodicity specified in MOD-026 Attachment 1". The attachment table format is being used because the SDT believes that it is the clearest way to present the periodicity information.** Why are the References listed in Section G included? They are described as being "beyond the scope of this Standard". **The references are industry documents related to excitation systems. They are provided as a courtesy only because the SDT believes they will be helpful to some users. The referenced documents are not required reading nor are they required for compliance with the standard.** The language for R4 should be reworded as follows: "R4. Each Generator Owner shall provide revised model data or plans to perform model verification7 (in accordance with Requirement R2) to its Transmission Planner within 180 calendar days of prior to making changes to the excitation control system and plant volt/var control function that alter the equipment response8 characteristic." **The SDT drafted the standard recognizing the model verification requires expertise and calendar time. The model cannot be verified until the actual equipment is installed. While 180 days is the maximum time period that can be utilized to be deemed compliant, it should be recognized that in the vast majority of cases, the personnel that implement the excitation control and plant volt/var control function modifications would also perform testing of the new equipment including staged tests leading to a new model. As such, it would be expected that the final model would be submitted well before the 180 days afforded for compliance.** The way the language is currently written, the generator has to provide its revised model data or plans to perform model verification within 180 days of making the change. For up to 180 days after a change has been made the correct data still may

Organization	Yes or No	Question 5 Comment
		not have been made available to the Transmission Planner. This could have a significant impact on reliability. **The SDT drafted the standard recognizing the model verification requires expertise and calendar time. 180 days is the maximum time period that can be utilized to be deemed compliant. It is expected that all entities will strive to verify the model as quickly as practical.** The suggested rewording addresses this possibility. The suggested language would be in line with FERC approved language that is currently part of ISO Tariffs. What is the definition of Gross Nameplate Rating as used in the Standard? **The gross nameplate rating in the applicability of the standard is not capitalized. The gross nameplate rating refers to generator nameplate ratings.**
Response: Thank you for your comment. Please see responses above.		
Southern Company		We agree that the collection of preliminary excitation control system model data from the equipment manufacturer is outside the scope of this standard. Also, any pre-COD staged testing to collect equipment responses to be used to verify the model can be required via Interconnection Agreements. It is understood that any equipment responses collected through pre-COD staged testing with final equipment settings in place that is subsequently used for model verification per the Requirements in the standard would result in fulfilling the requirements for model verification for the next 10 years per the Periodicity Table or until a special circumstance occurs leading to an earlier model re-verification as detailed in Requirements R3, R4, R5, or R5. The limitation to allow sisterhood for only those units at the same physical location should be extended to all identical units for the same GO/GOP - a sister is a sister is a sister. The GO should be allowed to take credit if he can show that the physical location is not a factor in the comparison.

Organization	Yes or No	Question 5 Comment
		The SDT notes the general agreement among industry with using the proxy unit approach. The SDT respectfully maintains that the "same physical location" requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site walk down). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g. requirement for PSS in-service). To ensure all GO/GOP equipment meets standard intent, the SDT maintains the "same physical location" requirement is necessary. In section 4.2.1.1, and other places, we don't understand the use of "bulk power system" -shouldn't this be "Bulk Electric System". **Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.** In 4.2.1.2, second bullet, eliminate the word "comprised" as it is redundant with "consisting". The same redundant use of "comprised" is in section 4.2.2.2 and 4.2.3.2, second bullet. **Section 4.2.2 of the Facilities section under** **Applicability has been revised and the word "comprised" has been deleted.** In R2.1.4, the intended information is not clear - the closed loop voltage regulator part is not needed - it is part of the previous wording. In R2.2, replace "For plants" with "For applicable plants". Please add "where applicable" each time the "plant volt/var control" is used. **The SDT believes that the "closed loop voltage regulator" verbiage is needed to convey technical intent. Please note that at the beginning of the "Facilities" section, there is a phrase "For the purpose of this standard, the following Facilities are considered, "applicable units".**

Organization	Yes or No	Question 5 Comment
		Due to R5, the Planning Coordinator should be listed in the 4.1 Functional Entitles. **The reference to Planning Coordinator has been changed to Transmission Planner to be consistent with the Applicability section of the standard and to conform to NERC functional model.** R5 is confusing - the bullet items list what the GO response should include, but the sentence is written such that the list is what the model review must include. **The main body of the requirement includes the phrase right before the bullets "....that includes one of the following" which re-affirms that the one of the bullets is necessary.** In R2.1.1, please insert "or voltage at the generator terminal" to "at unit's point of interconnection". **Specific reference to point of connection is removed from Requirement R2 Part 2.1.1. Language has been modified to: "Documentation demonstrating the applicable unit's model response matches the recorded response for a voltage excursion from either a staged test or a measured system disturbance."**
Response: Thank you for your comment. Please see responses above.		
ACES Power Marketing Standards Collaborators		We continue to believe that this standard is overly administrative by memorializing the interactions between the Generator Owner, Transmission Planner and Planning Coordinator that occur to model the generator's excitation system. Most of the requirements are purely administrative and present compliance risk to the registered owners without commensurate reliability benefit. Addition of administrative requirements acts contrary to the recent efforts of FERC and NERC to eliminate compliance backlogs created by violations of requirements that present no reliability risk or benefits. This is the purpose of the FFT process that NERC initiated and FERC recently approved. Interestingly, within the approval order, FERC even suggested that these types of requirements need to be eliminated. Only two requirements are really needed to accomplish the purpose of this standard. They are: one

Organization	Yes or No	Question 5 Comment
		requirement for the Generator Owner to perform the test and one for the Transmission Planner to verify the model is accurate. Requirement R3 highlights the overly administrative nature of the standard and the problem with attempting to memorialize the cooperation that must occur between the Generator Owner and Transmission Planner to model the generator's excitation and volt/VAr control functions accurately. Requirement R3 allows a Generator Owner to simply respond with a technical basis for leaving its model intact which does not solve the Transmission Planner's model issue. Thus, this requirement does nothing for reliability because modeling problems cannot be left unsolved. It should be struck. **Requirement R3 is a "peer review" type requirement to ensure cooperation between the Generator Owner and the Transmission Planner. The SDT believes peer review is an essential part of the model verification process since the peer review provides the Transmission Planner an opportunity to review the data and identify problems or errors with information provided. The SDT believes that all entities will be equally motivated to resolve model issues. This process was over whelming supported by Industry based on their responses in prior postings.** We are not convinced Requirement R4 is needed. **Requirement 4 specifies the need for model verification due to changes to the excitation control system and plant volt/var control function that alter the equipment response characteristic. Without Requirement R4, there would be no trigger between the standard 10 year periodicity to update the model to reflect changes to the excitation system.** The situation of providing model updates when changes are made to the covered control systems is already covered in Attachment 1. Since Attachment 1 is referenced in Requirement R2, why is this additional Requirement R4 needed? If Requirement R4 is needed, we are assuming the drafting team did not think this situation was covered in Requirement R2. If this is the case, at the very least, Requirement R4 should reference Attachment 1. Otherwise, Attachment 1 would

Organization	Yes or No	Question 5 Comment
		not ever apply to the situation of applicable control system changes. **Requirement R4 specifies the need for model verification due to changes to the excitation control system and plant volt/var control function that alter the equipment response characteristic. Attachment 1 addresses the required periodicity and acceptable time delays to remain compliant.** For Requirement R5, there is no clarity for how soon the Generator Owner has to address the model concerns communicated by the Planning Coordinator. If the Generator Owner has the unit in its 10 year plan to test their generation fleet's control systems, they could simply communicate that plan which might be much longer than the Planning Coordinator intended. The drafting team needs to provide more guidance on whether the Generation Owner is expected to accelerate their plans for the unit in question by the Planning Coordinator and by how much. **The intent of the Requirement R5 is for Transmission Planners to use technical justification for validating models for units that meet NERC registry criteria but did not meet applicability threshold of the standard. The Generator Owner has 90 days from the receipt of a request to review and respond to the Transmission Planner's request. If the need for validation is agreed by Generator Owner, the Generator Owner has one calendar year from the date of submitted verification plan to complete validation.** For Requirement R5, who decides if the request is technically justified? Could the Generator Owner simply choose not to respond because they do not believe the request is technically justified? **The technical justification for a request is described in Footnote 4 on page 4 of the standard. However, Generator Owner can in writing challenge any findings of the Transmission Planner within 90 days of the request.** In the Background Information section of the comments, the drafting team indicated that the "standard is drafted to provide the proper cost/benefit balance for performing generator verification". Since the summaries of field test results posted

Organization	Yes or No	Question 5 Comment
		with the second draft of the SAR indicate the costs of these tests could range from $5,000 to $50,000 for a single unit and that does not even include opportunity costs from lost energy sales should the test cause the unit to trip, we believe it would be helpful for the drafting team to provide information on the cost/benefit that was discussed in the Background Information section of the comment form in the next posting. **The stance of the SDT concerning the proper cost/benefit balance was a result of the field test initiated by the Phase III-IV SDT. The field test involved participants from 4 regions including WECC, SERC, ERCOT, and MRO, and was conducted in 2006 to the summer of 2007. The final report is available on the NERC website. At the final face to face meeting of the Field Test, it was concluded by those in attendance that performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the exciter models used in dynamic simulations – but at the same time, everyone recognized that there is a monetary cost associated with verifying the models. The SDT believes that these applicability thresholds proposed in the draft standard is in support of the desire of the field test participants in that model verification will result in substantial accuracy improvement to the excitation models and associated Reliability based limits determined by dynamic simulations, while not unduly mandating costly and time consuming verification efforts. Also, it should be noted that industry experience has proven that the possibility of a unit trip during these tests is extremely low. If ambient monitoring is utilized, the risk is even lower as the collection of data is entirely passive.** The response to our comments regarding consideration for early compliance from the last posting was not satisfactory. In our comments we stated that we appreciated the drafting team's consideration to allow for early compliance based on past tests. However, we stated concerns regarding how to demonstrate this compliance because a registered entity was not required to retain documentation and may not be able to prove they completed a test. The drafting team responded that demonstration of compliance was beyond the scope of the drafting team. While

Organization	Yes or No	Question 5 Comment
		we agree demonstration of compliance for specific companies and situations are likely beyond the scope, demonstration of compliance in general is never beyond the scope. Drafting teams must write standard requirements with which can be complied. Given that the issue of evidence retention from before the effective date of the standard was one of the key subjects in the High-level review conducted by NERC for CAN-0008 recently at the request of the Trade Associations, we suggest the drafting team should consult the appropriate NERC subject matter experts to determine how to avoid these similar issues with this draft standard. **The verbiage for consideration for early compliance is, in part: "The Generator Owner has a verified model that is compliant with the applicable regional policies, guidelines or criteria existing at the time of model verification". The SDT believes that this conveys the intent that documentation required by those "regional policies, guidelines or criteria existing at the time of model verification" would constitute sufficient proof for early compliance.** Sections 4.2.1.2, 4.2.2.2, and 4.2.3.2 are confusing and potentially contradictory. First, these sections state that they apply to each generating plant/Facility greater than 100, 75 and 50 MVA respectively. Then, the second bullet under each of these sections applies to generating plant/Facility. How can there be a plant within a plant? **The SDT has removed the term "Facility from applicability section of the standard, except one time to clarify the use of the term "applicable units" throughout the standard.** With the first bullet, it appears the intent is to include generating units 20 MVA and greater within generating plants meeting the 100, 75, or 50 MVA thresholds, respectively. However, the second bullet really confuses us because it appears to bring in everything below 20 MVA which is not covered in the first bullet. These sections are further confused by the fact that they potentially apply a different threshold for individual generating units than section 4.2.1.1, 4.2.2.1, and 4.2.3.1

Organization	Yes or No	Question 5 Comment
		which apply to individual generating units. For example, 4.2.2.1 applies a 75 MVA threshold to an individual generating unit and then the first bullet of section 4.2.2.2 applies a 20 MVA unit threshold because it defines a generating plant/Facility as including one or more units. Using plant/Facility confuses the matter further. **The SDT has refined the aforementioned sections in the Applicability section to address your stated concerns.** The NERC Glossary of Terms uses a generator as an example of a Facility. In the second bullet under each segment, it appears the discussion is totally focused on a plant but despite the use of the singular Facility. **The SDT has removed the term "Facility from applicability section of the standard, except one time to clarify the use of the term "applicable units" throughout the standard.** The VRFs simply do not meet the NERC definitions for anything greater than Lower. Requirements R2 and R6 are written with Medium VRFs. All other requirements have Lower VRFs. Neither Requirement R2 nor R6 could be construed as affecting the electrical state or capability of the Bulk Electric System or the ability to monitor, control or restore it. Per NERC definition of Medium VRF, these are prerequisites for meeting a Medium VRF. For Requirement R1, the VRF justification for FERC Guideline 5 refers to the requirement having a high risk objective. This is not consistent with a Lower VRF. We agree with the Lower VRF and recommend removing the "high risk objective" language. **The language in the VRF Guidelines document for a Medium VRF is:** **Medium Risk Requirement** **A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under**

Organization	Yes or No	Question 5 Comment
		emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. The language in the VRF Guidelines document for a Lower VRF is: Lower Risk Requirement A requirement that is administrative in nature and a requirement that, if violated, would not be 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; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature. Requirement 2 requires that the Generator Owner "provide, for each of its applicable units, a verified generator excitation control system and plant volt/var control function model..." Model verification is not an administrative task. It requires physical verification of actual system responses. R6 requires the Transmission Planner to notify the Generator Owner whether or not the model that was provided is useable. This links directly with the verification process and has an equal impact to the validity of the model. All of the measurements use language that sounds like it is creating a new a requirement and is not consistent with language used in any other NERC standard. They all use "must include".

Organization	Yes or No	Question 5 Comment
		The SDT believes the measures support requirements by identifying what evidence or types of evidence could be used to show that an entity is compliant with the requirement. It should be noted that this is consistent with NERC guidelines and support documentation for drafting Standards. It is more typical to use "shall demonstrate", "shall make available", etc. These measurements should be made consistent with other NERC standards. All evidence requirements for proof of transmission should be dropped as they go above and beyond basic evidence requirements. **The SDT believes the measures support requirements by identifying what evidence or types of evidence could be used to show that an entity is compliant with the requirement. It should be noted that this is consistent with NERC guidelines and support documentation for drafting Standards.** Some examples of the proof include dated postal receipts, dated confirmation of facsimile, etc. When is a dated and signed letter not sufficient proof? Must it also be sent by registered mail? Furthermore, any of the proofs of transmission do not prove anything other than something was transmitted. They do not prove the evidence was transmitted. For example, a confirmation report will not prove anything other than some fax was sent. Even dated and time stamped email proves only that the email was sent. It does not prove it was received. **The examples were offered as such: these are examples. The SDT understands that the different regions and different entities will have their specific protocols for the requirements associated with NERC Standards. As such, these methods and examples are just to illustrate the flow of information, as the SDT perceives it. These methods and examples are not part of the Requirements, but listed in the Measures. Once again, the methods listed in the Measures are for reference, but are not intended to be an exhaustive and comprehensive list of the possible ways in which this could be implemented.** The Compliance Enforcement Authority section is not the latest approved language

Organization	Yes or No	Question 5 Comment
		being used by NERC. In the data retention section, there is no length of time given for how long a Generation Owner must retain information for Requirement R2 and its associated measurement. **The data retention section for Requirement R2 requires that they keep the latest model verification evidence.** The High and Severe VSLs for Requirement R5 need to be updated. They still refer to Subparts 5.2 and 5.3. The Subparts have been changed to a bulleted list which means they are options. Thus, missing one and meeting the other is full compliance and not partial compliance as the VSLs suggest. **Based on your comment, the SDT has revised the verbiage for the High VSL to not include any references to the sub bullets in Requirement R5, and revised the verbiage for the Severe VSL to include " OR The Generator Owner written response failed to indicate one of the sub bullets of Requirement R5."** We suggest the drafting team write a brief paragraph at the beginning of the Reference section to explain the inclusion of the References. Currently, it states that those references contain technical information that is out of scope of the standard. If so, what is the purpose of including them? We are not against including them but just believe a short explanation for their inclusion is necessary. **The references are industry documents related to excitation systems. They are provided as a courtesy only because the SDT believes they will be helpful to some users. The referenced documents are not required reading nor are they required for compliance with the standard. The statement used to introduce the references is consistent with that used in other standards.** The verification periodicity for row 3 in Attachment 1 needs to be updated from 356 days to 365 days. Furthermore, the drafting team should consider using a year to account for leap years. Otherwise, every four years we are shifting the compliance date up by one calendar day. **We have corrected the typographical error to say "365 days." The SDT believes**

Organization	Yes or No	Question 5 Comment
		that the use of "365 days" instead of "one year" is more appropriate and consistent with the use of "180 days" elsewhere in the standard.
Response: Thank you for your comment. Please see responses above.		
PSEG		We have these additional comments: a. The exclusion of synchronous condensers (and other reactive devices) in MOD-026-1 per the rationale provided in the Background (with which we agree) states "Synchronous condensers are not currently addressed in the NERC Registry Criteria" However, companion standards under Project 2007-09 (MOD-025-2 and PRC-019-1) are applicable to synchronous condensers. The GVSDT should address this inconsistency. **The SDT believes that MOD-026 is different from the other standards with respect to synchronous condensers due to the complex interaction required between the Transmission Planner and the Generator Owner, and thus believes it better to wait for efforts by others to define where synchronous condensers fit in the functional model.** b. The entire section 4.2 has language that includes "directly connected to the bulk power system." The BES is a subset of the BPS (per Order 743), and the GVSDT should consult with the SDT for Project 2010-17 - Definition of BES - to develop alternate language that instead refers to the BES. **Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.**
Response: Thank you for your comment. Please see responses above.		
ISO New England Inc		We suggest that the language for R4 be made more clear and state as follows."R4. Each Generator Owner shall provide revised model data or plans to perform model verification5 (in accordance with Requirement R2) to its Transmission Planner 180

Organization	Yes or No	Question 5 Comment
		calendar days prior to making changes to the excitation control system and plant volt/var control function that alter the equipment response6characteristic. The way the language is currently written, the generator merely has to provide its plans for model verification. This means that 6 months after a change has been made, the correct data still may not have been made available to the Transmission Planning. This could have a significant impact on reliability. The suggested language would be in line with FERC approved language that is currently part of ISO Tariffs.
Response: The SDT thanks you for your comment. The SDT drafted the standard recognizing the model verification requires expertise and calendar time. The time frames mentioned in the comment are the maximum time periods that can be utilized to be deemed compliant. It is expected that all entities will strive to verify the model as quickly as practical. The model representing the new equipment cannot be verified until the new equipment is installed. Also, this standard addresses model verification, not the submittal of preliminary design models.		
Southern California Edison Company		While an active closed-loop voltage regulation function is useful in distinguishing transient voltage and frequency responses within mere cycles or seconds of perturbations, a similar requirement should be added to MOD-026-1 to require variable generators who were exempted from the standard by the condition added to Attachment 1 to provide similar plant voltage/var control, design, and test data to the Transmission Planner. The automatic switching of capacitor banks and reactor banks can play a role in maintaining the voltage stability of the system.
Response: The SDT thanks you for your comment. The intent was not to give an exemption to any unit or plant that has a closed loop voltage regulation function. If a plant has a device that provides dynamic voltage regulation (such as a STATCOM, DVAR or SVC, and perhaps automatically controlled capacitors commonly found in Renewable Plants), these devices should be included in the model and should be validated. If the automatically controlled (mechanically switched) capacitor bank is in whole or a part of the primary dynamic volt/var response of the plant, it should be modeled and validated. Both PSS/e and PSLF have standard library models to represent automatically switched capacitor banks (SWSHNT in PSS/e and MSC1 in PSLF). Ultimately, the local		

Organization	Yes or No	Question 5 Comment
interconnection requirements should be used to determine if the automatically controlled capacitor banks are a primary means for dynamic volt/var regulation within any particular application. Based on review of a plant's application requirements, the testing /validation entity should determine if the automatic capacitor bank should be validated. Please reference Row 6 of Attachment 1 of the current draft of the standard.		
Exelon Corp.		Draft MOD-026-1 R.2.1 requires that the Generator Owner perform verifications subject to include certain information as specified in sub requirements 2.1.1 through 2.1.6. R 2.1.1 requires that the unit model response is matched to the recorded response for a voltage excursion at the "point of interconnection". For certain generating units the "point of interconnection" is on the high voltage side of the main power transformer (i.e., the switchyard disconnect switch). Because of this, the model would have to consider the impact of the main power transformer, auxiliary transformer, and auxiliary transformer loads all of which are not part of the generator/excitation system model. The Standard should be revised to state the response of interest is at the generator terminals and not at the "point of interconnection." **Specific reference to point of connection is removed from Requirement R2 Part 2.1.1. Language has been modified to: "Documentation demonstrating the applicable unit's model response matches the recorded response for a voltage excursion from either a staged test or a measured system disturbance."** Typically individual synchronous machines have generator excitation control systems and do not have volt/var control systems. The text "and / or" or "as applicable" should be added to all references to "volt/var model" in the Standard and the associated attachments. **Based on your and other industry comments, the SDT modified the phrase "generator excitation control system and plant volt/var control functions" to "generator excitation control system or plant volt/var control functions" to recognize that the use of the phrase "or" is technically correct the vast majority of the time.**

Organization	Yes or No	Question 5 Comment
		With respect to the SDTs response to Exelon's comment regarding the lack of acceptance criteria (refer to MOD-026-1 Consideration of Comments dated 2-23-12 pp 89-90), the following statements by the SDT need to be more clearly articulated within the body of the Standard. **"It should be noted that the standard is written so that the Generator Owner "owns' the model, and as such, even with the peer review process described, the Generator Owner has final say on the voltage excursion used, including sampling rate, for model verification as well as determining if the equipment recorded response satisfactorily matches the model's predicted response."** The current draft (draft 3) of MOD-026-1 R.3 requires that a Generator Owner provide a written response to its Transmission Planner if the Transmission Planner deems the functional model is not "usable", if there are technical concerns with the verification documentation, or if the model response did not match an actual event. This written response is to contain either plans for performing model verification, model changes or a technical basis for maintaining the current model. It appears from the comments of the SDT (see question 3 above) that the Generator Owner has final say on the model; however, if the opinion of the Transmission Planner differs from that of the Generator Owner there is the potential for a disagreement between the two entities. Given the potential for a dispute to occur and the lack of an "acceptance criteria" the SDT should consider adding in a provision for dispute resolution between the parties or clearly delineate that the GO has the final say. **The SDT believes that the draft Requirement clearly conveys that the GO has the final say as the draft standard does not list any additional processes. The SDT also believes that both parties will be equally motivated to resolve any technical issues with the model.**
Response: Thank you for your comment. Please see responses above.		

Organization	Yes or No	Question 5 Comment
Puget Sound Energy		None

PRC-024 Overall Summary Consideration: The GVSDT received valuable feedback from stakeholders regarding improvements to the standard. Many of the suggested edits were incorporated into the revised standard.

A slight majority of stakeholders were in agreement with the approach taken for Requirement R4. Of the stakeholders who did not agree with the approach, the reasons most often cited were that such estimates would not provide any reliability benefit, the estimates are difficult to calculate, and the time period allowed to respond to a request for an estimate (60 days) is too short. The SDT modified the structure of the requirement to clarify the intent and the limits of what entities could request a performance estimate, but did not change the time period allowed to respond.

A large majority of stakeholders indicated that they did not agree that it is technically achievable for new generation to meet the performance required in Requirement R5. The most common reason stated was that Attachment 1 did not correctly specify the WECC region underfrequency tripping limits. Other objections cited by more than one responder were that the curves in Attachments 1 and 2 are too stringent, that significant R&D work needs to be done on the design of a plant to meet the requirement, and that the cost of building such a plant would be too high with little corresponding gain in grid reliability. The SDT corrected the error in the Attachment 1 underfrequency curve and data table for the Western Interconnection. The SDT did not make any substantive changes to Requirement R5 since the SDT did not feel stakeholders presented valid arguments that the requirement could not be achieved technically, given that similar requirements are already in effect in other parts of the world.

Other specific revisions to the standard are:

- **The wording in Requirement R1 was revised for clarity, Part 1.1 (rate of change of frequency) was removed and new Parts 1.2 and 1.3 were added for consistency with Requirement R2 at the request of several stakeholders.**
- **Minor changes in the wording in Requirement R2 were made to improve clarity at the request of several stakeholders.**
- **The structure of Requirement R4 was modified and minor wording changes were made to improve clarity at the request of several stakeholders, though no changes were made to the intent of the requirement.**
- **Part 5.1 and Subpart 5.1.1 were incorporated into the body of Requirement R5 so that the remaining Parts of this requirement describe exceptions (i.e. allowances to trip).**
- **Minor wording changes were made at the request of multiple stakeholders to clarify wording in Parts 5.1 – 5.6 of Requirement R5.**

- **The allowable time to respond to a request for generator protection settings in Requirement R6 was increased from 30 days to 60 days at the request of several stakeholders.**
- **The Violation Risk Factors for Requirements R1, R2, and R5 were changed from High to Medium at the request of several stakeholders.**
- **Minor wording changes were made to Measures M3, M4, and M5 were made for clarity at the request of several stakeholders.**
- **The time frame referenced in Measure M6 was modified to correlate with the change made in Requirement R6.**
- **The wording in the Data Retention section was revised at the request of one stakeholder and now reflects the wording used in other recently-approved standards.**
- **Minor changes were made in the VSL's for Requirements R1, R2, R3, and R4 to add clarity or correct errors mentioned by several stakeholders.**
- **The wording in the Severe VSL for Requirement R5 was revised to add a reference to Parts 5.1 – 5.6 and the tardiness levels in the Requirement R6 VSL's were revised to reflect the change in the requirement.**
- **The underfrequency curve for the Western Interconnection and corresponding data table were corrected in Attachment 1 at the request of many stakeholders in the WECC region.**
- **Curves for the ERCOT Interconnection and a corresponding data table were added to Attachment 1 at the request of ERCOT.**
- **The term "base voltage" was replaced with "nominal operating voltage" in Clarification #1 to Attachment 2 at the request of several stakeholders.**
- **Minor wording changes were also made to Clarifications #2, and #5 to better convey the intent of the SDT in response to questions presented by several stakeholders.**

6. **Requirement R4 has been added for owners of existing units or generating plant/facilities to provide an estimate of the performance of the units during frequency and voltage excursions. This information is intended to provide Transmission Planners with information useful in performing planning studies. Do you agree with this approach? If not please explain and provide alternative language.**

Summary Consideration: A slight majority of stakeholders were in agreement with the approach taken for Requirement R4. Of the stakeholders who did not agree with the approach, the reasons most often cited were that such estimates would not provide any reliability benefit, the estimates are difficult to calculate, and the time period allowed to respond to a request for an estimate (60 days) is too short. The SDT modified the structure of the requirement to clarify the intent and the limits of what entities could request in a performance estimate, but did not change the time period allowed to respond.

Organization	Yes or No	Question 6 Comment
Independent Electricity System Operator	Negative	Requirement R4 asks owners of existing units or generating plant/facilities to provide an estimate of the performance of the units during frequency and voltage excursions. This estimate is difficult to provide with sound technical basis, and may not contribute to any more valid assessment of a generator's expected performance than a TP's conservative assumptions drawn from available information already provided by the GO and the standard's Attachments 1 and 2. In brief, this requirement does not appear to provide any reliability benefit at all.
Response: Thank you for your comments. The SDT appreciates your position, but was charged with meeting the recommendations of FERC Order 693 and the 2003 Blackout Report. Requirement R4 attempts to address a portion of the recommendation to provide better information to Transmission Planners regarding the performance of generating facilities during frequency and voltage excursions. This requirement is written such that the information is only provided if it is requested by a planner. If the planner does not believe the information received would be of any value, it is permissible to not make the request. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate."		
Oncor Electric Delivery	Negative	In a deregulated market, the Balancing Authority (BA) and Planning Authority (PA) are in the best position to provide a more strategic look at gathering this type of information and ensuring the necessary broad distribution. As a result, the receiving

Organization	Yes or No	Question 6 Comment
		of modeling data from a Generator Owner (GO) should be the responsibility of the PA or the BA and not the Transmission Planner or Transmission Operator. This approach provides a single clearinghouse for generator data, ensuring accuracy and consistency, from the GO which then can accessed by any impacted Registered Entities.
Response: Thank you for your comments. Planning Authority is no longer used in the current NERC Functional Model; the functions are now assigned to the Planning Coordinator, which is included in Requirement R4. The SDT believes that the Balancing Authority typically does not do long-term planning studies, but if the BA were interested in the performance estimate, he could work with the Transmission Operator or Transmission Planner to obtain the information.		
Wisconsin Electric Power Co., Wisconsin Electric Power Marketing	Negative	Requirement R4 is not reasonable since it is difficult to provide any meaningful estimate of performance during frequency excursions. **The SDT appreciates your position, but was charged with meeting the recommendations of FERC Order 693 and the 2003 Blackout Report. Requirement R4 attempts to address a portion of the recommendation to provide better information to Transmission Planners regarding the performance of generating facilities during frequency and voltage excursions. This requirement is written such that the information is only provided if it is requested by a planner. If the planner does not believe the information received would be of any value, it is permissible to not make the request. In addition, the SDT does not require Generator Owners to do extensive dynamic simulations to determine performance. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate." The SDT believes the Generator Owner could identify the most likely piece of equipment to fail to ride through (whether from contactor dropout or other mechanism) and estimate the time between that event and a generator trip due to the resulting process upset.** Also, the No Trip curve in Attachment 2 needs further clarity, especially when the Generator Owner has voltage relaying that is connected to VT's on the low-side of the GSU. **The SDT agrees that generator protection normally senses the voltage at the**

Organization	Yes or No	Question 6 Comment
		generator terminals. Because there are many configurations of the connections of the generators to the transmission systems, it is not practical to develop a single voltage curve defined at the generator terminals that equates to the voltage caused by an event on the transmission system. Each Generator Owner will have to determine how the transmission system event affects his specific generating units. This approach is consistent with FERC Order 661-A and other international grid standards that are in effect.
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Wisconsin Energy Corp.	Negative	PRC-024-1: Requirement R4 is not reasonable since it is difficult to provide any meaningful estimate of performance during frequency excursions. **The SDT appreciates your position, but was charged with meeting the recommendations of FERC Order 693 and the 2003 Blackout Report. Requirement R4 attempts to address a portion of the recommendation to provide better information to Transmission Planners regarding the performance of generating facilities during frequency and voltage excursions. This requirement is written such that the information is only provided if it is requested by a planner. If the planner does not believe the information received would be of any value, it is permissible to not make the request. In addition, the SDT does not require Generator Owners to do extensive dynamic simulations to determine performance. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate." The SDT believes the Generator Owner could identify the most likely piece of equipment to fail to ride through (whether from contactor dropout or other mechanism) and estimate the time between that event and a generator trip due to the resulting process upset.** Also, the No Trip curve in Attachment 2 needs further clarity, especially when the Generator Owner has voltage relaying that is connected to VT's on the low-side of the GSU. **The SDT agrees that generator protection normally senses the voltage at the generator terminals. Because there are many configurations of the connections of**

Organization	Yes or No	Question 6 Comment
		the generators to the transmission systems, it is not practical to develop a single voltage curve defined at the generator terminals that equates to the voltage caused by an event on the transmission system. Each Generator Owner will have to determine how the transmission system event affects his specific generating units. This approach is consistent with FERC Order 661-A and other international grid standards that are in effect.
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Texas Reliability Entity	No	Most existing facilities are likely not designed to a frequency or voltage ride-through standard, and a useful estimate may be very difficult for owners to provide. Generator Operators may be able to document "known" equipment limitations. There are probably many examples of unknown equipment limitations, simply because a plant may not have experienced a fault condition that could expose the limitation.
Response: Thank you for your comments. The SDT agrees that most existing facilities are not designed to ride through a voltage excursion created by a three-phase fault at the plant substation. The SDT believes the Generator Owner could identify the most likely piece of equipment to fail to ride through (whether from contactor drop out or other mechanism) and estimate the time between that event and a generator trip due to the resulting process upset. The SDT was charged with meeting the recommendations of FERC Order 693 and the 2003 Blackout Report. Requirement R4 attempts to address a portion of the recommendation to provide better information to Transmission Planners regarding the performance of generating facilities during frequency and voltage excursions. This requirement is written such that the information is only provided if it is requested by a planner. If the planner does not believe the information received would be of any value, it is permissible to not make the request. In addition, the draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate."		
Exelon Corp.	No	The Frequency/Voltage Excursions should be limited to those listed in the standard, this should be explicitly stated in the requirement. 60 calendar days is an unreasonable amount of time to perform a study of this magnitude, suggest increasing the amount of time perform this study.

Organization	Yes or No	Question 6 Comment
Response: Thank you for your comments. The SDT believes there is value in allowing the estimate of performance for a voltage excursion specific to particular facilities (which would be less stringent than the curves in Attachment 2). The SDT does not require Generator Owners to do extensive dynamic simulations to determine performance. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate." The SDT believes the Generator Owner could identify the most likely piece of equipment to fail to ride through (whether from contactor dropout or other mechanism) and estimate the time between that event and a generator trip due to the resulting process upset.		
ACES Power Marketing Standards Collaborators	No	This requirement will essentially be redundant with standards MOD-026 and MOD-027. MOD-026 already requires the Generator Owner to verify its excitation and volt/VAr control systems. MOD-027 already requires the Generator Owner to verify its frequency response and its turbine/governor, load control and active power/frequency control models.
Response: Thank you for your comments. The SDT disagrees that this requirement is redundant with MOD-026 and MOD-027. Those standards require Generator Owners to verify the response of the excitation system (MOD-026) and frequency control system (MOD-027) to disturbances, but do not address the ability of a generating unit to ride through excursions.		
MRO NSRF	No	Since most existing facilities are likely not designed to a frequency or voltage ride-through standard, the estimate may be very difficult for owners to provide. Staged testing would not be practical for making this determination and engineering analysis may not have the accuracy to make it useful for use by Transmission Planners.
Response: Thank you for your comments. The SDT agrees that most existing facilities are not designed to ride through a voltage excursion created by a three phase fault at the plant substation. The SDT does not require Generator Owners to do extensive dynamic simulations or staged testing to determine performance. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate." The SDT believes the Generator Owner could identify the most likely piece of equipment to fail to ride through (whether from contactor dropout or other mechanism) and estimate the time between that event and a generator trip due to the resulting process upset. The SDT was charged with meeting the recommendations of FERC Order 693 and the 2003 Blackout Report. Requirement R4 attempts to address a portion of the recommendation to provide better information to Transmission Planners regarding the performance of generating facilities during frequency and voltage excursions. This requirement is written such that the information is only provided if it is requested by a		

Organization	Yes or No	Question 6 Comment
planner. If the planner does not believe the information received would be of any value, it is permissible to not make the request.		
PPL Electric Utilities and PPL Supply NERC Registered Organizations	No	Independent generators provide model data to the TP/TOP and TO, who then run their models, but we do not ourselves have means of predicting responses to voltage and frequency excursions. This is especially the case when one must, per R4.1, engage in the phenomenal complexity of calculating the transient performance of auxiliary buses and identifying the short-term drop-out thresholds of the multitudinous pieces of equipment they power. The references in R4.1 and 4.2 to experience, actual event histories or sound engineering judgment as alternatives to a computer model are not helpful, because meaningful assessments can be made only if one has relevant data (i.e. high-speed records of past disturbances, at HV, MV and LV voltage levels) and issue a PV. Further on the subject of complexity, there are a variety of aux bus configurations possible for our multiple-unit plants, any one of which could be deemed normal depending on circumstances. Having to check every aux bus configuration for every units-running combination would be unduly burdensome, even if it were possible. The fact that R4 cites "Frequency/Voltage Excursions" (apparently meaning simultaneous deviations of these parameters), while R5 is careful to refer to "frequency excursion or voltage excursion," adds confusion. Another concern is that the boundary conditions for the above-described analysis are presently undefined, with the standard invoking instead a "dynamic simulation provided by the Transmission Planner." For the reasons stated above, the proposed requirement R.4 should be eliminated.
Response: Thank you for your comments. The SDT did not intend that the Generator Owner have to estimate performance during simultaneous voltage and frequency excursions and has revised the wording in Requirement R4 to say, "…frequency or voltage excursion…" The SDT does not require Generator Owners to do extensive dynamic simulations to determine performance. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate." The SDT believes the Generator Owner could identify the most likely piece of equipment to fail to ride through (whether from contactor drop out or other mechanism) and estimate the time between that event and a generator trip due to the resulting process upset. The SDT was charged with meeting the recommendations of FERC Order 693 and the 2003 Blackout Report. Requirement R4 attempts to address a portion of the recommendation to provide better information to Transmission Planners		

Organization	Yes or No	Question 6 Comment
regarding the performance of generating facilities during frequency and voltage excursions.		
Luminant Power	No	An estimate of the time that a unit would remain on-line during or following a voltage or frequency event described by a Transmission Planner would be difficult if not impossible considering the complexity of the auxiliary system and would result in little value to the Transmission Planner. There is no known methodology to provide a consistent estimation or calculation of the value. Luminant recommends that the requirement be removed from the standard.
Response: Thank you for your comments. The SDT does not require Generator Owners to do extensive dynamic simulations to determine performance. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate." The SDT believes the Generator Owner could identify the most likely piece of equipment to fail to ride through (whether from contactor drop out or other mechanism) and estimate the time between that event and a generator trip due to the resulting process upset. The SDT was charged with meeting the recommendations of FERC Order 693 and the 2003 Blackout Report. Requirement R4 attempts to address a portion of the recommendation to provide better information to Transmission Planners regarding the performance of generating facilities during frequency and voltage excursions.		
Arizona Public Service Company	No	This type of data is not going to result into any more accurate simulation than the existing methodology which does not include this data. There are many other inaccuracies involved in modeling and scenario planning for islanding studies. It is a misconception that just by having more complex modeling will improve accuracy and thus reliability.
Response: Thank you for your comments. The SDT appreciates your position, but was charged with meeting the recommendations of FERC Order 693 and the 2003 Blackout Report. Requirement R4 attempts to address a portion of the recommendation to provide better information to Transmission Planners regarding the performance of generating facilities during frequency and voltage excursions. This requirement is written such that the information is only provided if it requested by a planner. If the planner does not believe the information received would be of any value, it is permissible to not make the request.		
Southern Company	No	We cannot agree with the approach of Requirement R4 due to the uncertainty about how to estimate the performance of "each" plant system, sub-system, or

Organization	Yes or No	Question 6 Comment
		component that could cause the unit to trip for the voltage excursion profile of Attachment 2. For most units, this estimate may vary from a few cycles (examples: dropout of low voltage motor contactors or an auxiliary control relay) to up to 1-2 seconds (examples: tripping of boiler controls or medium voltage motors). Determination of a more accurate time estimate would require detailed dynamic analysis, which would entail significant engineering study and involve assumptions and judgment based on experience. Data from actual event histories, if available, would likely not match all points of the Attachment 2 time-voltage profile. The voltage excursion profile needed for an evaluation would be the voltages present on the generator bus and plant distribution system auxiliary buses rather than at the point of interconnect. Without detailed analysis, only a rough estimate could be made which would probably be of limited value for transmission system analyses. A conservative approach would be the "go/no-go" approach and identify those units that are likely to trip for a specified voltage excursion. For the current requirements stated in R4, the 60 day time requirement would be a significant challenge for a GO to meet for a single unit. For GOs who have a large number of units and limited engineering resources, the 3-year phase-in period will be impractical to establish on many units the estimated performance of "each" plant system, sub-system, and component that could trip. Bottom line is, the concept may seem simple enough in principle, but these requirements cannot be practically met. We believe the scope of the standard should be limited to identification of the protection function trips per R1, R2, R3, and R6 only.

Response: Thank you for your comments. The SDT does not require Generator Owners to do extensive dynamic simulations to determine performance. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate." The SDT believes the Generator Owner could identify the most likely piece of equipment to fail to ride through (whether from contactor drop out or other mechanism) and estimate the time between that event and a generator trip due to the resulting process upset (similar to the go/no go methodology suggested). While it is possible that a Transmission Planner could request a performance estimate for all of a Generator Owner's units over the implementation period (which has been revised from three years to five years), the SDT feels the Transmission Planner would be more likely to only request the information for generators more critical to system stability. The SDT was charged with meeting the recommendations of FERC

Organization	Yes or No	Question 6 Comment
Order 693 and the 2003 Blackout Report. Requirement R4 attempts to address a portion of the recommendation to provide better information to Transmission Planners regarding the performance of generating facilities during frequency and voltage excursions.		
AECI	No	My concern with this requirement is that if a GO provides an estimate of how long they believe that the unit can ride out the event, then what will happen if they do not make this target? Will the GO be held responsible for not making this time? Due to this concern how accurate are these times that are provided by the GO going to be and how much will be a built in cushion?
Response: Thank you for your comments. There is no language in Requirement R4, Measure M4, or the associated VSL that indicates there would be any penalty to the Generator Owner if an excursion occurred and a generating unit did not perform as estimated.		
We Energies	No	It is very difficult to estimate generator performance during frequency or voltage excursions, especially frequency, and the best efforts to provide an estimate may not provide a meaningful result. It is proposed that the TO or TP could achieve the objective better by tracking transmission system voltage/frequency events that could have resulted in abnormal voltages at generating stations, and work cooperatively with the GO informally to determine the generator performance.
Response: Thank you for your comments. The SDT does not require Generator Owners to do extensive dynamic simulations. The process suggested in your comment would be one method of estimating the generating unit performance. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate."		
Manitoba Hydro	No	More detail is required in R4 to ensure that the Transmission Planner can model behavior before and after the disturbance. Information should be provided on how long the unit should take to ramp back to full power following a voltage or frequency excursion that doesn't cause the unit to trip.
Response: Thank you for your comments. The SDT believes it the uncertainties involved in trying to determine generator outputs		

Organization	Yes or No	Question 6 Comment
and ramp rates would not improve grid reliability.		
Independent Electricity System Operator	No	As indicated in our previous comment, we do not support having a requirement to obtain such an estimate. First of all, the requirement does not distinguish whether it applies to units that are equipped with frequency/voltage protective relays or otherwise. Secondly, the intent of providing the suggested estimate is to allow Transmission Planners to apply valid or supported assumptions in their planning studies. Given the requirements in Attachments 1 and 2 and Requirement R3 and the information already received, a TP can apply the following relevant assumptions to its planning studies: i. For units that are equipped with frequency/voltage protective relays, the GO's submitted relay settings will determine when the units will trip;ii. For units that are NOT equipped with frequency/voltage protective relays, the units are conservatively assumed to trip when the simulated frequency/voltage goes outside the bounds of Attachments 1 and 2. We do not see what other estimates that can be more relevant and valid than the above. We see that there may be some value in providing these estimates but only in the case of generators not equipped with frequency/voltage protective relays where tripping takes place beyond the no-trip zones of Attachments 1 and 2. For this information to be useful however, the generator's behavior must be predictable. While it may facilitate some "what-if" analysis, it is not clear that using this information would be more valid than applying the conservative assumption "b" above. We cannot envisage a Transmission Planner to use this additional information if this information cannot be ascertained to be more valid. In short, we do not believe provision of this estimate will provide any more valid assessment of a generator's expected performance than a TP's conservative assumptions drawn from available information already provided by the GO and Attachments 1 and 2. The estimate does not provide any reliability benefit at all.We suggest the SDT remove this requirement altogether.
Response: Thank you for your comments. The SDT appreciates your position, but was charged with meeting the recommendations of FERC Order 693 and the 2003 Blackout Report. Requirement R4 attempts to address a portion of the recommendation to provide better information to Transmission Planners regarding the performance of generating facilities during		

Organization	Yes or No	Question 6 Comment
frequency and voltage excursions. This requirement is written such that the information is only provided if it requested by a planner. If the planner does not believe the information received would be of any value, it is permissible to not make the request.		
Ingleside Cogeneration LP	No	Ingleside Cogeneration believes that this is an open-ended requirement that allows multiple planning and operations entities - not just Transmission Planners - to require complex assessments completely at their discretion. There is no allowance for the availability of GO resources nor any need for the requestor to provide a reliability justification. Furthermore, we would like to point out that the modeling validation requirements of MOD-027-1 (frequency) and MOD-026-1 (voltage) must, by definition, include the impact of protective relay settings. This means that a need for an estimate of performance is not necessary as real performance data will always be available. In addition, these Standards already allow recourse for a re-validation if Transmission Planners cannot reconcile their models with actual generator performance.
Response: Thank you for your comments. The SDT does not require Generator Owners to do extensive dynamic simulations to determine performance. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate." The SDT disagrees that MOD-026 and MOD-027 evaluate voltage and frequency protection functions. Those standards require Generator Owners to verify the response of the excitation system (MOD-026) and frequency control system (MOD-027) to disturbances, but do not address the ability of generator protection or a generating unit to ride through excursions.		
Luminant Energy	No	An estimate of the time that a unit would remain on-line during or following a voltage or frequency event described by a Transmission Planner would be difficult if not impossible considering the complexity of the auxiliary system and would result in little value to the Transmission Planner. There is no known methodology to provide a consistent estimation or calculation of the value. Luminant recommends that the requirement be removed from the standard.
Response: Thank you for your comments. The SDT does not require Generator Owners to do extensive dynamic simulations to determine performance. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required		

Organization	Yes or No	Question 6 Comment
to develop the estimate." The SDT believes the Generator Owner could identify the most likely piece of equipment to fail to ride through (whether from contactor drop out or other mechanism) and estimate the time between that event and a generator trip due to the resulting process upset (similar to the go/no go methodology suggested). The SDT was charged with meeting the recommendations of FERC Order 693 and the 2003 Blackout Report. Requirement R4 attempts to address a portion of the recommendation to provide better information to Transmission Planners regarding the performance of generating facilities during frequency and voltage excursions. The SDT cannot remove the requirement without replacing it with another method of giving the Transmission Planner the necessary information.		
Duke Energy	No	Generator Owners don't currently have the capability to provide this information, and will need time to obtain the capability and perform the studies. Requirement R4 should be removed from Effective Date sections 5.1, 5.2 and 5.3 because one, two or three years is insufficient time. R4 should have its own effective date section specifying an effective date of the first day of the first calendar quarter five years following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter five years following Board of Trustees adoption. Requirement R4 should also be revised to allow the Generator Owner 180 days (instead of 60 days) to respond to a request and provide an estimate of a unit's performance during frequency/voltage excursions.
Response: Thank you for your comments. The SDT does not require Generator Owners to do extensive dynamic simulations to determine performance so has not extended the time period for responding to a request for the estimate. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate." The SDT agrees with the suggestion to change the implementation period to five years.		
Ameren	No	At the end of R4.2, we suggest to add "the Transmission Planner's voltage recovery characteristic from R2 part 2.1.1" since that may well have bearing on the estimate. We understand the reasons for such studies, but we ask the GVSDT to consider the fact that more than 60 days may be needed to estimate generating unit performance especially the first time it is done for each unit. As long as this applies only to generator frequency and voltage protective relaying (and not to station auxiliaries)

Organization	Yes or No	Question 6 Comment
		developing these estimates in the time frame mentioned earlier is achievable.
Response: Thank you for your comments. The standard has been modified to require the requesting entity to provide a "…frequency or voltage excursion defined by the voltage or frequency profile at the point of interconnection described by dynamic simulation provided by the requestor (Reliability Coordinator, Planning Coordinator, Transmission Operator or Transmission Planner that monitors or models the associated generating unit)." The SDT does not require Generator Owners to do extensive dynamic simulations to determine performance, so has not extended the time period for responding to a request for the estimate. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate."		
Cowltiz PUD	No	Cowlitz is only concerned with the 60-day response time. The responding entity should be given some leeway to negotiate a delivery time if the 60-day response is not feasible. Otherwise, substandard estimates will be provided to avoid violation of the standard.
Response: Thank you for your comments. The SDT does not require Generator Owners to do extensive dynamic simulations to determine performance so has not extended the time period for responding to a request for the estimate. The SDT agrees with many commenters that it is not realistic to provide an extremely precise estimate. The quality of the estimate is not specified in the requirement, measure, or associated VSL. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate."		
Indiana Municipal Power Agency	No	IMPA does not agree that there would be any gain in reliability by requiring Generator Owners to give an estimate on the performance of a unit or the overall plant during a frequency or voltage excursion. Will such a request include specific parameters that would be expected on the system to narrow down this imposition of an estimate upon the Generator Owner? Will Generator Owners be capable of providing an estimate that may be required under this item? In addition, the Transmission Planner is to provide the dynamic simulation of the voltage and frequency profile at the point of interconnection. There is no guidance in the Standard as to how often or what means will be used to submit the (new) profile(s) to the GO - will it be annually, seasonally or?? IMPA also has concerns with attempting

Organization	Yes or No	Question 6 Comment
		to accurately predict the ride-thru capabilities of a generating unit/plant on a consistent basis. As an example, if the unit/plant was operating during an extreme and prolonged period of heat and humidity it's characteristics and ability to ride thru a frequency and/or voltage event will be different than if running during the opposite - extreme cold and wind. Many of the unit/plant auxiliary systems may be located in areas that are not climate controlled and it would be extremely difficult to consistently predicte how they will react during temperature extremes.
Response: Thank you for your comments. As you note in the comment, the standard requires the requestor to specify the voltage or frequency excursion for which the Generator Owner is to provide an estimate of the time duration the generator unit will remain connected. The SDT does not require Generator Owners to do extensive dynamic simulations to determine performance, so has not extended the time period for responding to a request for the estimate. The SDT agrees with many commenters that it is not realistic to provide a precise estimate. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate." The SDT believes the Generator Owner could identify the most likely piece of equipment to fail to ride through (whether from contactor drop out or other mechanism) and estimate the time between that event and a generator trip due to the resulting process upset. While the requirement does not limit the number of requests that may be submitted by a Reliability Coordinator, Planning Coordinator, Transmission Operator, or Transmission Planner, it also does not prevent the Generator Owner from responding with the same estimate to each request.		
Pepco Holdings Inc. & Affiliates	Yes	Agree in principle with attempting to quantify the ability of the unit (including affect on plant auxiliary systems) to remain connected during voltage and frequency excursions. However, the present wording of this requirement may not result in sufficient information to fully model the performance of the unit in dynamic studies. It may be more constructive to request a modified set of voltage and frequency ride through curves (similar to Attachments 1 & 2) that represent the Generator Owner's best estimate of a no trip zone for each unit, taking into account the performance of plant auxiliary systems, as well as any other protection / control setting, or operational limitation, that would prevent the unit from remaining on line within the no-trip zone as defined in Attachments 1 & 2. This would provide the Transmission Planner with sufficient information to fully model the anticipated performance of the

Organization	Yes or No	Question 6 Comment
		unit in their dynamic studies.
Response: Thank you for your comments. The SDT believes that requiring the Generator Owner to produce a set of curves that define successful performance would require more resources and would not provide any more useful information than the approach currently defined in Requirement R4. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate."		
Xcel Energy	Yes	We agree that the current wording (which removes the requirement to provide a probability of ride through) is an adequate means of achieving the reliability goal.
Response: Thank you for your comments.		
American Electric Power	Yes	AEP agrees with this approach for Attachment 1 only. We also have the following comments about the reference to Attachment 2 in R4. The reliability advantage to be gained from the inclusion of Attachment 2 is unclear, unprecedented and potentially costly. With respect to Attachment 1, any information that a GO can provide about a potential for their unit to trip within the no-trip zone of Attachment 1 will assist the Planning Coordinator in devising a UFLS program for their area, which they are obligated to do under PRC-006-1. A successfully designed UFLS program depends on knowing whether or not generation would trip prior to operation of all stages of UFLS. If it is known that a generator could trip prior to all stages of UFLS, apart from protection settings that would be reported to them under R1 of this standard, the PC ought to know that. Of course, we understand that a GO would not be held accountable under R4 for unknown factors that may result in tripping of their unit within the no-trip zone of Attachment 1. Attachment 1 should be referenced because it would be difficult for the TP to come up with simulation results that would adequately convey in a comprehensive fashion the coordination that should take place between UFLS and generation tripping apart from Attachment 1. We also believe reference to Attachment 1 is necessary for consistency in the application of R4 throughout an interconnection. We therefore conclude that it is desirable for overall reliability purposes to reference Attachment 1 in R4. We also point out that

Organization	Yes or No	Question 6 Comment
		curves of the nature of those in Attachment 1 have long existed as guidelines for generation performance during frequency excursions in each of the reliability regions. GOs are familiar with these types of curves, and generating units have been designed with these guidelines in mind. With respect to Attachment 2 being referenced in R4, the reliability advantage is not as clear, but we ask the SDT to consider again that it may be difficult for the TP to come up with simulation results that would adequately convey in a comprehensive fashion the possible voltage excursion events that a generating unit may be subject to, and for which it may be desirable to know whether or not a given generating unit would be able to ride through that disturbance. Reference to Attachment 2 may be desirable for, again, consistency in the application of R4 throughout an interconnection. However, in contrast to frequency, voltage is a local quantity and so it is not as critical to system reliability that GOs report voltage excursion trips within the no-trip zone of Attachment 2. The translation of the no-trip zone of Attachment 2 to internal generating plant voltages that would need to be determined is not straightforward, though that translation would need to be made by a GO regardless of whether they would receive point-of-interconnection voltage simulations from a TP or be directed to Attachment 2. We conclude that reference to Attachment 2 in R4 may have reliability benefits that the SDT may want to consider, but we do not believe reference to Attachment 2 is as essential as reference to Attachment 1.If the SDT did not include reference to Attachment 2, that should not have a bearing on the reference to Attachment 1. We assert that, because of the different characteristics of frequency and voltage, it would not be inconsistent to reference Attachment 1 but not Attachment 2.

Response: Thank you for your comments. The SDT agrees that it will be easier for a Generator Owner to estimate generating unit performance for a frequency excursion than to estimate performance for a voltage excursion. The SDT does not require Generator Owners to do extensive dynamic simulations to determine performance. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate." For a voltage excursion, the SDT believes the Generator Owner could identify the most likely piece of equipment to fail to ride through (whether from contactor drop out or

Organization	Yes or No	Question 6 Comment
other mechanism) and estimate the time between that event and a generator trip due to the resulting process upset.		
Western Electricity Coordinating Council		I am unsure of the intent of the phrase "estimate of the performance of the units during frequency and voltage excursions." Is this intended to mean that the owners should estimate whether or not the unit will stay connected, or provide some estimate of the unit's dynamic performance and response to an event? I also don't understand the purpose of this requirement. If models already exist and are available to the Transmission Planners, then the owners should be validating the model. As part of the validatio process the owners should be able to tell the Transmission Planner what the performance will be. Is this for units for which models have not been validated?
Response: Thank you for your comments. The wording in Requirement R4 has been revised so that it now states, "…the time duration the existing unit or generating plant or generating Facility will remain connected (considering performance of the auxiliary systems as well as the generator) as a result of a frequency excursion or voltage excursion…" It is only an estimate of if the unit is expected to ride through the event or to trip. There is no connection between this requirement and the verification of excitation response or frequency response models as defined in Standards MOD-026 and MOD-027.		
Northeast Power Coordinating Council	Yes	
Southwest Power Pool Standards Development Team	Yes	
Puget Sound Energy	Yes	
Dominion	Yes	
Imperial Irrigation District (IID)	Yes	
Tennessee Valley Authority	Yes	

Organization	Yes or No	Question 6 Comment
GO/GOP		
PacifiCorp	Yes	
Massachusetts Attorney General	Yes	
Dynegy	Yes	
PSEG	Yes	
ISO New England Inc	Yes	
American Transmission Company, LLC	Yes	
South Carolina Electric and Gas	Yes	
GenOn Energy	Yes	
Essential Power, LLC	Yes	
FirstEnergy Corp	Yes	
Austin Energy	Yes	
Southern California Edison Company	Yes	
Georgia Transmission	Yes	

Organization	Yes or No	Question 6 Comment
Corporation		
American Wind Energy Association	Yes	
Los Angeles Department of Water and Power		LADWP does not have comments on this question at this time.

7. **Requirement R5 requires a Generator Owner's new unit or generating plant/facility to be able to stay on line when exposed to point-of-interconnection frequency or voltage excursions depicted in the curves of Attachment 1 and Attachment 2. Do you believe this requirement is technically achievable for new units or generating plant/facilities? Please provide comments supporting your answer. Please provide along with your comment, what you believe the timeframe is needed to implement this requirement.**

Summary Consideration: A large majority of stakeholders indicated that they did not agree that it is technically achievable for new generation to meet the performance required in Requirement R5. The most common reason stated was that Attachment 1 did not correctly specify the WECC region underfrequency tripping limits. Other objections cited by more than one responder were that the curves in Attachments 1 and 2 are too stringent, that significant R&D work needs to be done on the design of a plant to meet the requirement, and that the cost of building such a plant would be too high with little corresponding gain in grid reliability. The SDT corrected the error in the Attachment 1 underfrequency curve and data table for the Western Interconnection. The SDT did not make any substantive changes to Requirement R5 since the SDT did not feel stakeholders presented valid arguments that the requirement could not be achieved technically, given that similar requirements are already in effect in other parts of the world. The SDT did not feel objections to the cost or lack of reliability benefit could be considered as overriding FERC Order 693.

Organization	Yes or No	Question 7 Comment
Avista Corp.	Negative	The curve depicting the "no trip zone" for WECC in Attachment A is not consistent with the overfrequency and underfrequency requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan (Plan). A step is missing in the curve for the underfrequency requirements. The table representing the points on the "no trip zone" curve for WECC is also missing the same step as the plot. Additionally the presentation of the information in the table is confusing. As presented, the table specifies a time range of staying connected for selected specific frequencies. The table should specify a specific time for staying connected for frequency ranges. For example, as currently depicted in the table, a generator would need to stay connected up to 0.75 seconds (or between 0 and 0.75 seconds) at 57.0 Hz. The WECC Plan allows for instantaneous trips at 57.0 Hz. Further, the WECC Plan requires the generator to stay connected for 45 cycles (0.75 seconds) for frequencies greater than 57.0 Hz. but less than or equal to 57.3 Hz. This is not accurately reflected in the Table. The plot in Attachment A and the associated tables must be corrected to accurately

Organization	Yes or No	Question 7 Comment
		reflect the requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan.
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected.		
Balancing Authority of Northern California	Negative	Regarding Attachment for the "OFF NOMINAL FREQUENCY CAPABILITY CURVE" o The WECC ONFLS plan vs. the PRC-024 plan do not match for the low-frequency duration. Please refer to the submitted WECC Comments. o Regarding the PRC-024 Attachment I curves, the multiple regional frequency curve overlay is quite busy and difficult to discern. Please consider posting separate curves for the various interconnection. o It is unclear whether or not frequency events that fall on the "line" allow for the generator to trip. For instance the WECC Off-Nominal Frequency Plan allow for instantaneous trip for frequency excursions f ? 57.0 Hz. Please identifying the allowable trip-time values for each interconnection table at the given time delay.
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected.		
BrightSource Energy, Inc.	Negative	The curve depicting the "no trip zone" for WECC in Attachment A is not consistent with the overfrequency and underfrequency requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan (Plan). A step is missing in the curve for the underfrequency requirements. The table representing the points on the "no trip zone" curve for WECC is also missing the same step as the plot. Additionally the presentation of the information in the table is confusing. As presented, the table specifies a time range of staying connected for selected specific frequencies. The table should specify a specific time for staying connected for frequency ranges. For example, as currently depicted in the table, a generator would need to stay

Organization	Yes or No	Question 7 Comment
		connected up to 0.75 seconds (or between 0 and 0.75 seconds) at 57.0 Hz. The WECC Plan allows for instantaneous trips at 57.0 Hz. Further, the WECC Plan requires the generator to stay connected for 45 cycles (0.75 seconds) for frequencies greater than 57.0 Hz. but less than or equal to 57.3 Hz. This is not accurately reflected in the Table. The plot in Attachment A and the associated tables must be corrected to accurately reflect the requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan.
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected.		
Chelan County Public Utility District #1	Negative	The curve depicting the “no trip zone” for WECC in Attachment A is not consistent with the overfrequency and underfrequency requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan (Plan). A step is missing in the curve for the underfrequency requirements. The table representing the points on the “no trip zone” curve for WECC is also missing the same step as the plot. The presentation of the information in the table is confusing. As presented, the table specifies a time range of staying connected for selected specific frequencies. The table should specify a specific time for staying connected for frequency ranges. For example, as currently depicted in the table, a generator would need to stay connected up to 0.75 seconds (or between 0 and 0.75 seconds) at 57.0 Hz. The WECC Plan allows for instantaneous trips at 57.0 Hz. Further, the WECC Plan requires the generator to stay connected for 45 cycles (0.75 seconds) for frequencies greater than 57.0 Hz. but less than or equal to 57.3 Hz. This is not accurately reflected in the Table.
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected.		
City of Austin dba Austin	Negative	Regarding Attachment for the “OFF NOMINAL FREQUENCY CAPABILITY CURVE” o

Organization	Yes or No	Question 7 Comment
Energy		Please separate out the drawings for the various interconnection curves so they are not all on one graph. **The SDT feels that the overlay of each variance is beneficial to understanding the differences between the regions. The data tables that follow the graph provide the precise details of each curve.** o Formally state that the “line” in the graph is not included in the No Trip Zone. Currently, the only way to know whether the “line” is in or out is this note on the graph. Regarding the “Curve Data Points:” tables **There is already a statement on the graph that states that the no trip zone does not include the lines.** o Please clarify the Frequency delineation by adding where appropriate or a text description such as “up to and including” or “up to but not including”. **There is already a statement on the graph that states that the no trip zone does not include the lines and the data tables have been reformatted to make this clearer.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
City of Farmington	Negative	FEUS agrees with the comments submitted by WECC: "The curve depicting the “no trip zone” for WECC in Attachment A is not consistent with the overfrequency and underfrequency requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan (Plan). A step is missing in the curve for the underfrequency requirements. The table representing the points on the “no trip zone” curve for WECC is also missing the same step as the plot. Additionally the presentation of the information in the table is confusing. As presented, the table specifies a time range of staying connected for selected specific frequencies. The table should specify a specific time for staying connected for frequency ranges. For example, as currently depicted in the table, a generator would need to stay connected up to 0.75 seconds (or between 0 and 0.75 seconds) at 57.0 Hz. The WECC Plan allows for instantaneous trips at 57.0 Hz. Further, the WECC Plan requires the generator to stay connected for 45 cycles (0.75 seconds) for frequencies greater than 57.0 Hz. but less than or equal to 57.3 Hz. This is not accurately reflected in the Table. The plot in Attachment A and the associated tables must be corrected to accurately reflect the requirements of the

Organization	Yes or No	Question 7 Comment
		WECC Coordinated Off-Nominal Frequency Load Shedding Plan."
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected.		
City of Redding	Negative	Regarding Attachment for the "OFF NOMINAL FREQUENCY CAPABILITY CURVE" - The WECC ONFLS plan vs. the PRC-024 plan do not match for the low-frequency duration. - Suggest to separate out the drawings for the various interconnection curves so they are not all on one graph. - Formally state that the "line" in the graph is not included in the No Trip Zone. Currently, the only way to know whether the "line" is in or out is this note on the graph. WECC formally indicates it in their table with the "<" signs.
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected. The note on the graph of Attachment 1 formally states that the No Trip Zone excludes the boundary line.		
Clark Public Utilities	Negative	I have voted negative because the PRC-024 criteria for generator frequency ride through and generator voltage ride through are not consistent with current WECC practices and proposals. Regarding frequency, WECC has had its Off Nominal Frequency Plan in place for many years. In addition, Reliability Standard Project WECC-0065 is proposed regional generator frequency ride through plan. Both of those plans use a long existing frequency ride through schedule. PRC-024 as proposed has a frequency ride through that neglects one of the low frequency points in the WECC plans. The 58.4 Hz setpoint (missing in PRC-024) avoids a low frequency area will result in damage to combustion turbines. PRC-024-1 must have a WECC low frequency ride through as follow: 57.0 HZ (0 - 0.75); 57.3 HZ (0.75 - 7.5); 57.8 Hz (7.5 - 30); 58.4 Hz (30 - 180); 59.4 Hz (>180). The overfrequency setpoints in PRC-024 are consistent with WECC practices. **The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has**

Organization	Yes or No	Question 7 Comment
		also been corrected. Additionally, the voltage ride through is confusing. In WECC, generators are supposed to be able to run continuously from 1.10 pu to 0.9 pu. I urge the STD to look at the work in the now terminated WECC-060 standards project (see the document entitled The Technical Basis for the New WECC Voltage Ride). The PRC-024 curve point data table seems to indicate that instantaneous trips are not allowed for 1.20 pu overvoltage. There is no reason for not allowing an instantaneous trip at this high of voltage. The generator will probably trip on overexcitation at this level anyway. The table needs to be informative enough so that if the data points were plotted, the expected curve would result. Looking at the curves it appears the table should read as follows for overvoltage. 1.05 pu (no trip); 1.10 pu (1.0 - 600.0); 1.15 pu (0.5 - 1.0); 1.175 pu (0.2 - 0.5); 1.20 pu (0 - 0.2). To avoid confusion the undervoltage criteria should read as follows. 0.95 pu (no trip); 0.90 pu (2.0 - 600.0); 0.75 pu (2.0 - 3.0), 0.65 pu (0.3 - 2.0); 0.45 pu (0.15 - 0.3); 0.00 pu (0.15). **The SDT acknowledges that certain regions may have more stringent voltage requirements, but does not believe that the standard should require the entire continent to meet the most stringent requirements. The data table for Attachment 2 has been reformatted to make the information clearer**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Colorado Springs Utilities	Negative	The curve depicting the "no trip zone" in Attachment A is not consistent with the overfrequency and underfrequency requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan (Plan). A step is missing in the curve for the underfrequency requirements. The table representing the points on the "no trip zone" curve is also missing the same step as the plot. Additionally the presentation of the information in the table is confusing. As presented, the table specifies a time range of staying connected for selected specific frequencies. The table should specify a specific time for staying connected for frequency ranges. For example, as currently depicted in the table, a generator would need to stay connected up to 0.75 seconds

Organization	Yes or No	Question 7 Comment
		(or between 0 and 0.75 seconds) at 57.0 Hz. The WECC Plan allows for instantaneous trips at 57.0 Hz. Further, the WECC Plan requires the generator to stay connected for 45 cycles (0.75 seconds) for frequencies greater than 57.0 Hz. but less than or equal to 57.3 Hz. This is not accurately reflected in the Table. The plot in Attachment A and the associated tables must be corrected to accurately reflect the requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan.
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected.		
Consumers Energy	Negative	"Related to undervoltage criteria, the 18 cycle at 45% of generator voltage would put a great deal of strain on the plant auxiliary systems and that may not be something these systems are able to withstand. The same would be true of a fault that produces 65% voltage at the generator terminals for 2 seconds. These comments relate specifically to Consumers Energy. However, it is likely that many others have similar equipment and would have the same issues. Please also note that the proposed standard does not align with ANSI C37.102, IEEE Guide for AC Generator Protection or with the NERC Technical Reference Document entitled Power Plant and Transmission System Protection Coordination." My vote is the same on the non-binding poll.
Response: Thank you for your comments. Please note that the voltage levels specified in Attachment 2 are at the point of interconnection to the transmission system. They would not correlate directly with the auxiliary bus voltages, especially if the auxiliaries are unit-connected. The SDT does not believe this proposed standard is in conflict with either the IEEE or the NERC documents cited. Please inform the SDT of the specifics of your concerns.		
MEAG Power	Negative	Regarding Attachment for the "OFF NOMINAL FREQUENCY CAPABILITY CURVE" o The WECC ONFLS plan vs. the PRC-024 plan do not match for the low-frequency duration. o We'd like them to separate out the drawings for the various interconnection curves so they are not all on one graph. o Formally state that the "line" in the graph is not included in the No Trip Zone. Currently, the only way to

Organization	Yes or No	Question 7 Comment
		know whether the “line” is in or out is this note on the graph.
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected. The note on the graph of Attachment 1 formally states that the No Trip Zone excludes the boundary line.		
Municipal Electric Authority of Georgia	Negative	Regarding Attachment for the “OFF NOMINAL FREQUENCY CAPABILITY CURVE” o The WECC ONFLS plan vs. the PRC-024 plan do not match for the low-frequency duration. o We’d like them to separate out the drawings for the various interconnection curves so they are not all on one graph. o Formally state that the “line” in the graph is not included in the No Trip Zone. Currently, the only way to know whether the “line” is in or out is this note on the graph.
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected. The note on the graph of Attachment 1 formally states that the No Trip Zone excludes the boundary line.		
Pacific Gas and Electric Company	Negative	The curve depicting the “no trip zone” for WECC in Attachment A is not consistent with the overfrequency and underfrequency requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan (Plan). A step is missing in the curve for the underfrequency requirements. The table representing the points on the “no trip zone” curve for WECC is also missing the same step as the plot. Additionally the presentation of the information in the table is confusing. As presented, the table specifies a time range of staying connected for selected specific frequencies. The table should specify a specific time for staying connected for frequency ranges. For example, as currently depicted in the table, a generator would need to stay connected up to 0.75 seconds (or between 0 and 0.75 seconds) at 57.0 Hz. The WECC Plan allows for instantaneous trips at 57.0 Hz. Further, the WECC Plan requires the generator to stay connected for 45 cycles (0.75 seconds) for frequencies greater than 57.0 Hz. but less than or equal to 57.3 Hz. This is not accurately reflected in the Table. The plot in Attachment A and the associated tables must be corrected to accurately

Organization	Yes or No	Question 7 Comment
		reflect the requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan.
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected.		
Portland General Electric Co.	Negative	The curve depicting the “no trip zone” for WECC in Attachment A is not consistent with the overfrequency and underfrequency requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan (Plan). A step is missing in the curve for the underfrequency requirements. The table representing the points on the “no trip zone” curve for WECC is also missing the same step as the plot. Additionally the presentation of the information in the table is confusing. As presented, the table specifies a time range of staying connected for selected specific frequencies. The table should specify a specific time for staying connected for frequency ranges. For example, as currently depicted in the table, a generator would need to stay connected up to 0.75 seconds (or between 0 and 0.75 seconds) at 57.0 Hz. The WECC Plan allows for instantaneous trips at 57.0 Hz. Further, the WECC Plan requires the generator to stay connected for 45 cycles (0.75 seconds) for frequencies greater than 57.0 Hz. but less than or equal to 57.3 Hz. This is not accurately reflected in the Table. The plot in Attachment A and the associated tables must be corrected to accurately reflect the requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan.
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected.		
Sacramento Municipal Utility District	Negative	Regarding Attachment for the “OFF NOMINAL FREQUENCY CAPABILITY CURVE” o The WECC ONFLS plan vs. the PRC-024 plan do not match for the low-frequency duration. Please refer to the submitted WECC Comments. o Regarding the PRC-024

Organization	Yes or No	Question 7 Comment
		Attachment I curves, the multiple regional frequency curve overlay is quite busy and difficult to discern. Please consider posting separate curves for the various interconnection. o It is unclear whether or not frequency events that fall on the "line" allow for the generator to trip. For instance the WECC Off-Nominal Frequency Plan allow for instantaneous trip for frequency excursions f ? 57.0 Hz. Please identifying the allowable trip-time values for each interconnection table at the given time delay.
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected. The note on the graph of Attachment 1 formally states that the No Trip Zone excludes the boundary line.		
Seattle City Light	Negative	A) Regarding Attachment for the "OFF NOMINAL FREQUENCY CAPABILITY CURVE" o The WECC ONFLS plan vs. the PRC-024 plan do not match for the low-frequency duration. o Please separate out the drawings for the various interconnection curves so they are not all on one graph. It is difficult to read as presented. o Formally state in the standard that the "line" in the graph is not included in the No Trip Zone. Currently, the only way to know whether the "line" is in or out is a note on the graph. B) Regarding timing of various proposed activities: o Clarify the time given to Generator Owners to document all the equipment limitation that prevents compliance with the proposed Requirements R1 and R2, in reference to Requirement R3. o Provide a timeline on when to communicate the removal of a documented limitation if it takes more than 30 days to remove or repair the limitation after it is identified. (R3.1 requires the communication within 30 days of the identifying the limitation, but the repair or removal could take longer than 30 days, depending what the causes for the limitation are.)
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected. The note on the graph of Attachment 1 formally states that the No Trip Zone excludes the boundary line.		

Organization	Yes or No	Question 7 Comment
Northeast Power Coordinating Council	No	The exception in 5.2 should not be allowed. Each generating unit that is registered based on the NERC Registry Criteria as a single unit, or as part of a generating facility, should comply with PRC-024 without exception. Simultaneous loss of 10 percent of the generators at a number of installations could introduce severe reliability concerns. This standard allows loopholes which undermine reliability. **Part 5.2 gives an allowance for loss of up to 10% of units at a site with many small units, which is analogous to a runback in power on a single larger unit. The SDT does not agree that the exceptions written unduly compromise reliability.** Suggest revising Requirement 5.6 from "may retroactively grant a temporary exemption" to "may grant a retroactive temporary exemption". **The SDT agrees and has made the suggested revision.** The magnitude of voltage excursions at the point of interconnection may be different from the generator terminals where generator relays receive their voltage inputs. **The SDT agrees that the voltage at the point of interconnection to the transmission system will almost always be different than the voltage at the generator terminals. It is not practical to define the generator terminal voltage for an event on the transmission system considering all of the different configurations of generators and transformers. Each Generator Owner will have to evaluate the designs for his particular equipment.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Exelon Corp.	No	It should be noted that even if a relay is not set to operate according to the curves in the attachments, a minute deviation will exist in the operation of the relay, and as such, a protection system may operate in what the SDT has deemed the "no trip zone." If a relay operates in that zone, then an entity will technically be out of compliance with this standard even though it set its protection system correctly as per the standard. An allowable tolerance needs to be included in the requirements in order to capture real world conditions.

Organization	Yes or No	Question 7 Comment
Response: Thank you for your comments. Relays that are known to drift from their settings should either be calibrated more frequently or set such that a tolerance is built into the relay setting so that the drift will not cross the "no trip zone" boundary.		
Texas Reliability Entity	No	While it is technically feasible to set generator protective relays to meet the intent of this Standard, there are technical limitations that may prevent manufacturers from achieving it, especially if the term "generating plant" includes auxiliary equipment within the plant that is required for the generator to continue to operate. The standard needs to clarify if and how the limitations of auxiliary equipment are to be addressed in connection with applicable generating facilities.
Response: Thank you for your comments. NERC standards do not specify how reliability goals are to be accomplished. There are already similar requirements in effect in parts of Europe and Asia. The implementation schedule for Requirement R5 allows six years before the requirement goes into effect in order to allow North American engineers to determine optimal methods for accomplishing the goal.		
ACES Power Marketing Standards Collaborators	No	It is not clear to us why this requirement is needed given the many tariffs that already exist to govern interconnection requests. These tariffs already have well established facility connection requirements. If the requirement persists, we believe it actually belongs in the FAC-001 standard which establishes facility connection requirements for new facilities including generators. While we believe that this requirement is probably technically achievable in most cases, there should be exceptions available. It looks like Part 5.3 will allow the Transmission Planner to offer these exceptions. However, this does not consider that the Transmission Planner in many cases (especially organized markets) is not the entity evaluating interconnection requests. Thus, the Planning Coordinator should be allowed to grant exceptions in those situations as well. **The SDT was charged with meeting the recommendations of FERC Order 693 and the 2003 Blackout Report. The SDT does not agree that placing the requirement in an Interconnection Agreement would achieve the desired performance goal.** The need to supply the bases for the estimate in Part 4.2 is not clear, offers no

Organization	Yes or No	Question 7 Comment
		reliability benefit and is administrative in nature. Of the three bases listed, (experience, actual event histories, or sound engineering judgment) what will the RC, PC, TOP, or TP do with the bases? Will they decide the bases are invalid and substitute their own judgment? If so, what is the purpose of getting an estimate from the Generation Owner anyway? It appears to be a documentation requirement that offers no reliability benefit or even information for which the recipient of the information could take action. **The SDT agrees and has removed the wording that required the Generator Owner to supply the basis for the estimate to the requesting entity.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Puget Sound Energy	No	Steam units appear to have very tight frequency requirements, and the damage is cumulative. In order to protect the prime mover, after several under frequency operations the units may need to immediately trip offline.
Response: Thank you for your comments. A number of regions in North America already require operation to underfrequency levels more stringent than those described in this standard. Manufacturers are able to build turbines to meet these requirements. If a particular unit has experienced cumulative damage to the extent it can no longer meet Requirement R5, the Generator Owner may request an exemption from the Reliability Coordinator per Part 5.5. The RC can determine if there is more reliability gain to the grid by having the unit operational with a risk that it may not remain connected during an excursion.		
MRO NSRF	No	A Standard cannot tell us what or how a generator needs to be built. Section 215 of the Federal Powers Act “(i) Savings Provisions, (2) This section does not authorize the ERO or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services”. We believe that R5 is directing “GO’s to design, build and maintain new unit...” and is in violation to the Federal Power Act as stated above. **This requirement does not specify what equipment a generation facility needs to install. It does specify how it is to perform under certain conditions. The requirement does not indicate that a Generator Owner has to build**

Organization	Yes or No	Question 7 Comment
		anything at all, so the cited section of the Federal Power Act does not apply. It is true that a new plant that trips due to an excursion as defined in this standard would be out of compliance (with certain caveats as described in Parts 5.1 – 5.7). Since there are already similar grid requirements in effect in parts of Europe and Asia, the SDT believes it is possible to build a plant to meet Requirement 5 without a need for "future technology." The question was posed to ascertain if anybody is aware of valid technical reasons why it cannot be done with existing technology. There are many factors that a Generator Owner must consider when making a decision to build a new facility. Regulatory compliance may be one factor. As R5 is written, if an entity builds a new unit and it trips for a voltage or excursion event within the parameters of Attachment 1 and 2, the entity is non compliant. **The SDT agrees that this interpretation is correct. However, per Requirement R5, Part 5.5, the Generator Owner could ask the Reliability Coordinator for a retroactive exemption if he determines how to address the limitation that caused the unit to trip.** This Requirement seems to be based on future technology that does not exist today. The SDT should state that the parameters of Attachment 1 and 2 "should" prevent a unit from tripping. R5 is written as an absolute and may reduce a new unit from being built. With the risk of non compliance being $1 million per day, it is easier and less risky not to even build a new unit. **There are already similar requirements in effect in parts of Europe and Asia, so the SDT does not believe meeting the reliability goal will require "future technology." Evaluation of risks and rewards has always been a part of determining when and where to build generating resources.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
PPL Electric Utilities and PPL Supply NERC Registered Organizations	No	It is possible for new facilities to buy steam turbines that permit operation in accordance with Att.1. We cannot confirm that it is possible to do so for all fossil unit sizes or generation unit types, however, and recommend that question 7 above be put to OEMs. This is particularly the case for gas turbine engines, for which the

Organization	Yes or No	Question 7 Comment
		limiting factor may be surge avoidance rather than resonance margins. Note also that such units may auto-unload at abnormal frequencies. This action may not provide the grid ride-out capability wanted, despite satisfying R5's no-trip requirement. The general acceptability stated above for steam turbines bears clarification, however, because OEM guidelines for off-frequency operation typically have a lifetime basis. That is, each transient results in cumulative fatigue damage. The frequency curves of PRC-024-1 are consequently not acceptable for an unstable grid that often swings to the max-specified deviations, and a statement should be added to this standard to the effect that the no-trip zones of Att. 1 apply for frequency excursions to the extremes no more frequently than once per decade. **A number of regions in North America already require operation to underfrequency levels more stringent than those described in this standard. Manufacturers are able to build turbines to meet these requirements. If a particular unit has experienced cumulative damage to the extent it can no longer meet Requirement R5, the Generator Owner may request an exemption from the Reliability Coordinator per Part 5.5. The RC can determine if there is more reliability gain to the grid by having the unit operational with a risk that it may not remain connected during an excursion.** Att. 2 presents a problem in that the deviation location is specified to be the point of interconnection, but GOs are being asked to confirm that all MV and LV devices required to maintain the unit on-line will not drop-out. An excursion to -10% voltage on the 230 kV span would correspond to -10% on the LV and MV systems only for theoretically ideal transformers, and the actual transient at critical loads may be greater. It would not be possible in any event to get OEMs to guarantee that the auxiliary equipment they supply will not drop-out for the Att. 2 excursions of 10 minutes at -10% voltage, 2 sec at -35% or 0.2 sec at -55%. The industry standard on this subject is ANSI C84.1, which stipulates voltage boundaries of +/- 5% for continuous operation and +/- 10% for emergency operation of no specified duration. If NERC feels that the criteria of Att. 2 are important for BES reliability they should start by asking the appropriate ANSI and IEEE committees to revise their standards

Organization	Yes or No	Question 7 Comment
		accordingly. We cannot support PRC-024-1 until its criteria become the nationally-accepted norm, because we otherwise would be making a commitment that it is impossible to fulfill. **The SDT agrees that studies will need to be done to design generating units (especially their auxiliary systems) to be able to ride through the types of transmission system voltage excursions defined in this standard. Since similar requirements are already in effect in parts of Europe and Asia, the SDT believes it is technically feasible. ANSI C84.1 sets standards for steady-state operating voltages and does not apply to voltage transients.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Luminant Power	No	Although this requirement may be achieveable, it is highly probably that as the unit ages, components will begin deteriate such that they will not be able to ride through severe voltage or frequency excursions. For example, Luminant has done testing of 480v contactors that when purchased new exhibit a drop out voltage level but over time, the drop out level will deteriate to a level. Since there is no method for determining when to replace equipment susceptible to voltage ride through criteria, this requirement is not auditable for the maintain requirement. The “maintain” requirement should be removed. The cost of meeting this requirement could potentially discourage new generation. Overall, requirement R5 provides little benefit to the reliability of the BES, and Luminant recommends that this requirement be removed.
Response: Thank you for your comments. The SDT is charged with meeting the reliability recommendations of FERC Order 693 and the 2003 Northeast Blackout Report. Maintenance is required for most equipment to ensure reliable operation. Contactor coils may have to be supplied from a source isolated from transmission system voltage excursions to ensure their reliable operation.		
Progress Energy	No	Progress Energy has a concern associated with the voltage ride through curve referenced in R5 (Attachment 2). The concern is not about setting the relay protection to ride through this transient or the generators capability of riding through

Organization	Yes or No	Question 7 Comment
		such a transient but of the physical capability associated with the large pumps and motors in the auxiliary equipment that would be subjected to this transient. A lot has to do with the size of the motors at the 4160 or 6900 volt level and the control relays at the 480 volt level. After 9 cycles at zero voltage the phase of the motor decay voltage and the incoming line voltage of the large motors may have shifted significantly causing large currents to be drawn when the voltage is restored to the motor. This could cause significant cyclical torques on motor shafts that can damage the shaft over time. Also the control contactors for most 480 volt control circuits do not hold in for less than 60 -70 % voltage. The capability of UPS systems are not sufficient to power the large motors being discussed and it may not be feasible to UPS all the plant 480 volt control circuitry. (We wouldn't be concerned with 480 if we thought we would lose higher voltage equip...) To implement this requirement as presently worded appears to be impractical and could prevent building of any new generating facilities at reasonable cost. **The SDT agrees that shaft torques on large motors is something that needs to be considered in designing the auxiliary system, but that is a concern for existing plants as well unless they have high speed under voltage bus tripping. Presumably, a new facility designed to ride through the voltage excursion described in the standard would include means of mitigating some of the effects of the excursion (e.g. unit-connected auxiliary transformers) which would reduce the shock on motor shafts. The SDT does not believe it would be necessary to carry the 480 V auxiliary loads on a UPS system. It would be sufficient to power the contactor coils with a UPS or from DC to ensure that they don't drop out on an excursion. Similar voltage ride through requirements are already in effect in parts of Europe and Asia so it appears that it is possible to design facilities to achieve the required performance.** There needs to be some ability to deviate for the specific requirements of the voltage curve in Attachment 2 if it can be show that the fault clearing time for the bulk electric system that the unit is connected to is different than the specific voltage requirements of Attachment 2 or there needs to be some more specific wording excluding the auxiliary equipment from the requirements of this voltage curve. **Part**

Organization	Yes or No	Question 7 Comment
		5.3 of Requirement R5 allows the Generator Owner to use the site-specific voltage recovery characteristic provided by the Transmission Planner for that site. Attachment 2 gives engineers and manufacturers the outer bounds of what might have to be met when designing equipment and facilities for multiple locations.
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Tennessee Valley Authority GO/GOP	No	There are specific areas within the no-trip zone curves in attachments 1 & 2 that would violate nuclear safety limits, which are controlled by the NRC. Also, the turbines of large steam-turbine units may be exposed to unsafe operating conditions within the no-trip zone of the frequency curve.
Response: Thank you for your comments. Requirement R5 does not apply to existing plants (nuclear or otherwise). Existing plants with documented technical limitations (including nuclear safety considerations) may obtain an exemption from portions of the No Trip Zones defined in the standard through the process described in Requirement R3.		
Arizona Public Service Company	No	Yes, the requirement is technically achievable. However there is a problem with measure and how compliance may enforce it. Generating units trip for many other reasons other than frequency and voltage excursions. The meaure, as written, will require a GO to prove that the unit(s) did not trip due to frequency or voltage excursion which may be impossible to prove. Even if it finds other reasons, it may be hard to prove that frequency and voltage excursion did not contribute to that other reason. Thus, a GO may be non-compliant unless for each unit trip it can clearly prove that the frequency and voltage excursion did not contribute to trip, which may be impossible to prove.
Response: Thank you for your comments. The SDT believes it is general practice for Generator Owners to investigate and determine the cause of all generating unit trips. Recording unit speed (for synchronous units) or system frequency does not seem overly burdensome. Determining local transmission system voltage may require coordination with the Transmission Operator in some cases, but is not unachievable. This requirement would necessitate adding a step to a trip investigation to evaluate this information to determine if there was an excursion at the time of the trip.		

Organization	Yes or No	Question 7 Comment
PacifiCorp	No	While PacifiCorp has no concerns with this Requirement R5 as applied to new units or generating plant/facilities meeting the point of interconnection frequency excursion performance depicted in Attachment 1 (for the corrected WECC curve), PacifiCorp believes that new units or generating plant/facilities should meet the voltage excursions performance depicted in Attachment 2; however, ultimately it will be up to generator manufacturers to implement necessary facility changes to withstand the voltage excursions.
Response: Thank you for your comments. The SDT appreciates the support for the reliability goals. We would add that it will require changes in auxiliary system configuration and equipment as well as the turbine and generator manufacturers' inputs to achieve the goal		
Southern Company	No	We recommend R5 be eliminated. New plants should be subjected to the same requirements as existing plants. The design of plant systems, sub-systems, and components are based on industry technical standards (ANSI, IEEE, ASME, etc.). Establishment of new NERC plant performance requirements must be coordinated with the industry through those standard processes. We believe significant R&D will be required to achieve significant new plant design requirements that can be used to revise the industry technical standards and that plant, system, and equipment designers and builders can meet. The scope of systems and components that must be addressed includes, but is not limited to, turbine generators, transformers, feed pump systems/controls, boiler control systems, reactor protection systems, emergency diesel generators, AC motors, pumps, fans, AC motor contactors, auxiliary relays, etc. In addition, significant costs will be incurred by the industry that we believe demand further justification.
Response: Thank you for your comments. The implementation schedule calls for six years beyond approval of the standard before Requirement R5 goes into effect. The SDT believes this is enough time to develop the required designs. Similar grid requirements are already in effect in parts of Europe and Asia so it appears to the SDT that existing technology exists to meet the requirements of this standard.		

Organization	Yes or No	Question 7 Comment
AECI	No	In my opinion, there needs to a definition of what is considered to be a new plant. Many plants are being built that were actually plants and projects that started 10 years ago. I do not believe that those plants should be included.
Response: Thank you for your comments. The SDT believes that Footnotes 2 and 4 provide a clear definition of "existing" plants and "new" plants. Plants that are already in the design or construction stages are not considered "new" plants.		
American Electric Power	No	AEP believes that the requirement for new units and plants to not trip within the no-trip zone of Attachment 1 is reasonable, and has precedence in existing reliability region guidelines.To not trip within the no-trip zone of the Attachment 2 is another matter. AEP believes Attachment 2 is inappropriate as a requirement on conventional generation for the following reasons:(1) It has not been found necessary to impose such a requirement as Attachment 2 on conventional generation in the past and we question why this should be proposed now. The appearance of such graphs seems to have been in response to the performance of wind farms that tripped off-line by protective relays when minor fault disturbances occurred on the transmission system. Attachment 2 may thus be an appropriate requirement for wind turbine generators and other non-conventional generation. We ask the SDT why such a requirement now needs to be imposed on conventional generation. If this is being done solely for the standard to appear technology neutral, it does not remove the fact that a new, unnecessary, and possibly onerous requirement is being imposed. **The SDT is charged with implementing the reliability improvement recommendations from FERC Order 693 and the 2003 Northeast Blackout Report. The SDT is working under the assumption that when industry approved the SAR for this project it agreed that the standard provided a reliability gain.** (2) Application of Attachment 2 to conventional generation is not straightforward because of the need to translate point-of-interconnection voltage to plant or unit internal voltage, particularly in the time period following fault removal (.15 seconds). Conventional synchronous generators have a substantial capability to control the voltage they are subjected to during a system disturbance (unlike most wind farms)

Organization	Yes or No	Question 7 Comment
		and whose critical auxiliary systems are usually (and should be) served from the generator bus (low side of GSU) and are thus shielded to some degree by the GSU impedance from voltage excursions on the transmission system. **The SDT agrees that it will require engineering studies when designing new generating units to determine the effect of the transmission system voltage excursion on the generator terminals and on the various auxiliary bus voltages taking into consideration the configuration of the various transformers. The SDT does not believe this is unachievable.** (3) Back in 2005, FERC Order 661-A contained a requirement for wind farms to ride through point-of-interconnection faults up to 9 cycles as determined by the actual fault clearing time at the interconnection station. The final order was thought to be sufficient to ensure wind farm fault ride-through by intervening parties including NERC and AWEA without the need for a graph along the lines of Attachment 2. Justification for the content of the final order was that all generation would be treated equitably. Why does the SDT now think it necessary to impose Attachment 2 on new generation? It would seem that deference to TPL standards for the types of transmission system disturbances where stability should be maintained should continue to be an acceptable ride-through criterion for all types of generation. Reference to Attachment 2 in R5 should thus be replaced by a requirement for all generation to ride through normally cleared 3-phase or unbalanced faults at the POI not to exceed 9 cycles. **If the Transmission Planner for a new generation facility can provide the voltage profile for that specific site, then per Part 5.2 the Generator Owner can design his new facility to ride through that profile even if it is less stringent (i.e. uses faster clearing and faster voltage recovery) than Attachment 2. The voltage envelope described in Attachment 2 provides equipment OEM's with an outer boundary on the voltage stress they have to design for.** (4) We do not know the incremental cost to comply with Attachment 2 under R5; however, we believe that it could be very costly to design and build synchronous generating units that would, with a high degree of confidence, remain on-line for any and all disturbances whose POI voltage falls within the no-trip zone. Attachment 2

Organization	Yes or No	Question 7 Comment
		would also be a new requirement without historical precedent and the SDT has not stated how reliability would be improved. With uncertain reliability benefits and uncertain and potentially high incremental costs to comply, we do not think the SDT is in a position to impose this requirement.For these reasons, we believe that reference to Attachment 2 in R5 should be removed. **There are similar voltage ride through requirements already in effect in parts of Europe and Asia. The SDT is charged with implementing the reliability improvement recommendations from FERC Order 693 and the 2003 Northeast Blackout Report. The SDT agrees that generating units designed and built to meet Requirement R5 will be more costly than those that cannot meet this reliability goal. The SDT is not in a position to place a monetary value on the consequent reliability gain. The SDT is working under the assumption that when industry approved the SAR for this project it agreed that the standard provided a reliability gain.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Luminant Energy	No	Although this requirement may be achieveable, it is highly probably that as the unit ages, components will begin deteriate such that they will not be able to ride through severe voltage or frequency excursions. For example, Luminant has done testing of 480v contactors that when purchased new exhibit a drop out voltage level but over time, the drop out level will deteriate to a level. Since there is no method for determining when to replace equipment susceptible to voltage ride through criteria, this requirement is not auditable for the maintain requirement. The "maintain" requirement should be removed. The cost of meeting this requirement could potentially discourage new generation. Overall, requirement R5 provides little benefit to the reliability of the BES, and Luminant recommends that this requirement be removed.
Response: Thank you for your comments. The SDT is charged with meeting the reliability recommendations of FERC Order 693 and the 2003 Northeast Blackout Report. Maintenance is required for most equipment to ensure reliable operation. Contactor coils may have to be supplied from a source isolated from transmission system voltage excursions to ensure their reliable		

Organization	Yes or No	Question 7 Comment
operation.		
Duke Energy	No	The proposed bands should be considered by new plant designers and incorporated into their design basis if feasible. Specific criteria have not been provided in new plant design guidance provided by EPRI Utility Requirements Document (URD) nor in other industry standards used by new plant designers. The frequency band was considered for some new plant design basis and no concerns were identified. It's not clear if all or even most of the designers for other nuclear/fossil designs have considered this.The proposed voltage band has caused many concerns and probably is not achievable for existing or new steam plants because electrically powered equipment (motors, MCC components, contactors, etc.) has been and is normally designed for proper operation as follows:The normal voltage boundaries have been specified to be for the steady-state operating conditions based on the ANSI C84.1-2006 “American National Standard for Electric Power Systems and Equipment - Voltage Ratings (60Hz)”as follows:a. Normal Conditions: Â±5% Continuous Durationb. Emergency Conditions: Â±10% not specified DurationThese Criteria are currently widely used in practice and can be complied with by all types of new generating plants designed with an in-plant voltage regulation capability. In connection with these criteria, all new equipment, both on the transmission system and in new generation plants must be chosen in order to be able to operate and withstand these voltage excursions.For transients, the above should be applied for conditions lasting more than one second. Transient conditions lasting more than one second, can be more severe and the equipment can still ride through it. A design solution to address severely degraded voltage lasting more than one second is to utilize expensive voltage regulation devices, normally not utilized at power generation plants. This standard shouldn’t dictate a solution to the situation where a generator goes offline due to low voltage on the transmission system, because in many cases the generator going offline may not be a problem for the overall transmission system. In situations where it is a problem, a collaborative effort between the Transmission Planner and the Generator Owner would be the best approach (see AREVA white paper that has been provided to the SDT).An R&D effort

Organization	Yes or No	Question 7 Comment
		should be considered to investigate steam plant ride through capabilities if a criteria is needed.
Response: Thank you for your comments. The voltage profile described in Attachment 2 is specified at the transmission system. This cannot be directly applied to the auxiliary system buses unless the Generator Owner insists on using substation-connected auxiliary transformers. Operating the auxiliaries from unit-connected transformers would provide a much better voltage profile to the equipment. As noted, ANSI C84.1 applies to steady state voltages. This standard does not state that any transient condition lasting longer than one second is defined as steady state. In IEEE 1159 a long duration variation is defined as being longer than one minute. The SDT is charged with implementing recommendations from FERC Order 693 and the 2003 Northeast Blackout Report. The implementation schedule calls for six years beyond approval of the standard before Requirement R5 goes into effect. The SDT believes this is enough time to develop the required designs. Similar grid requirements are already in effect in parts of Europe and Asia so it appears to the SDT that existing technology exists to meet the requirements of this standard.		
Ameren	No	(1) We understand this to include generating plant auxiliary load based on the GVSDT reply to our draft 2 comments. If still is the case, please clarify and explicitly insert “including its auxiliary systems” after generating plant so that all GO understand it. **The SDT agrees and has added “(including auxiliary systems)” to the wording in the requirement.** (2) Many 480V class contactors drop out in the 70% to 80% voltage range, so we doubt they’ll ride through the 2 to 3 second portion of the voltage excursion. The middle portion of your voltage excursion curve is more stringent than the CBEMA and SEMI curves, both of which recover to 80% in 0.5 sec. Transmission system protection in our system will clear faults faster than the proposed voltage excursion curve, thus in effect yielding a voltage recovery curve with shorter durations for the voltages specified. We would ask the GVSDT to consider what we feel is a more realistic approach of designing a new generating facility to the Transmission Planner’s voltage recovery characteristic allowed for in R2 part 2.1.1 is achievable now. What was the basis on which the proposed voltage excursion curve developed? **The curves cited in your comments specify voltages at the equipment. The voltages specified in Attachment 2 of the standard are at the high side of the generator step-**

Organization	Yes or No	Question 7 Comment
		up transformer. A new generation facility would have to be designed such that contactor coils and delicate electronic equipment are isolated from the full extent of a transmission system voltage excursion. If the Transmission Planner for a new generation facility can provide the voltage profile for that specific site, then per Part 5.3 the Generator Owner can design his new facility to ride through that profile even if it is less stringent (i.e. uses faster clearing and faster voltage recovery) than Attachment 2. The voltage envelope described in Attachment 2 was developed from studies in WECC and SERC of multiple fault scenarios and their recovery characteristics. It is similar to the envelope described in FERC Order 661-A that wind units already are required to meet and to grid requirements already in effect in parts of Europe and Asia.
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Southern California Edison Company	No	The language in the requirement is acceptable, but the frequency curve identified for generators is too restrictive for hydro facilities, which are often dispatched to provide VAR and voltage support. SCE's hydro generation plants operate at very low RPM, which provides them with the ability to operate safely above (60-78 Hz) and below (<58 Hz) the frequency curves in Attachment 1 and Attachment 2, respectively. As a transmission operator, SCE applies this flexibility in its hydro generation plants to compensate for system instabilities resulting from VAR and voltage excursions. In addition, SCE's employs its hydro plants to support system restoration.
Response: Thank you for your comments. The SDT is not clear on your response. It appears that you want hydro units to be able to operate below 57.0 Hz and/or above 61.7 Hz that are the boundaries for the WECC interconnection. The standard does not require that any generators trip if the frequency goes outside of the No Trip Zone defined in Attachment 1, it only prevents tripping within the No Trip Zone.		
Cowltiz PUD	No	Cowlitz supports Clark County PUD's position. Please verify the following: The problem is that PRC-024 skips a frequency step in the low frequency operating area. The generator frequency ride through of Attachment 1 is inconsistent with the

Organization	Yes or No	Question 7 Comment
		current WECC Off Nominal Frequency plan and the frequency ride through in the proposed WECC-0065 regional criteria. The PRC-024 ride through could cause a combustion turbine to operate at 58 Hz for a duration that would cause damage to the turbine blades. The current WECC ONF ride through avoids this.
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected.		
Indiana Municipal Power Agency	No	Is the technology to meet this requirement even currently available to a newly built generating facility? To force such a requirement on newly built generating facilities at this time, one is speculating that the technology will be available. Can we risk reliability of the gird on such speculation (Generator Owners not building generating facilities because they cannot meet this requirement)? What if the technology is not available? IMPA believes that this standard will be reviewed by NERC in five years or sooner and at the time the SDT can revisit this possible requirement to see if the technology to keep a generating facility on line during a voltage or frequency excursion has been proven. Or a condition could be added that says new units shall be designed and built with the frequency and voltage excursion equipment if it is the industry standard, readily and commercially available and comes at competitive market prices.
Response: Thank you for your comments. The implementation schedule calls for six years beyond approval of the standard before Requirement R5 goes into effect. The SDT believes this is enough time to develop the required designs. Similar grid requirements are already in effect in parts of Europe and Asia so it appears to the SDT that existing technology exists to meet the requirements of this standard.		
Pepco Holdings Inc. & Affiliates	Yes	Yes, it is possible to design a new facility to operate within the requirements identified in this standard. However, it may require specification of equipment with higher than normal overvoltage capabilities. Also, significant analyses would have to be conducted on the behavior of plant control systems (exciter controls, boiler

Organization	Yes or No	Question 7 Comment
		controls, etc.), as well as equipment connected to auxiliary busses (including low voltage motor contactors) to ensure that all systems are designed with appropriate ride-through capabilities.
Response: Thank you for your comments. The SDT agrees with your position.		
ISO New England Inc	Yes	The exception in 5.2 should not be allowed. Each generating unit that is registered based on the NERC Registry Criteria as a single unit, or as part of a generating facility, should comply with PRC-024 without exception. Simultaneous loss of 10 percent of the generators at a number of installations could introduce severe reliability concerns. This standard appears to allow loopholes which undermine reliability.
Response: Thank you for your comments. Part 5.2 (now 5.1) gives an allowance for loss of up to 10% of units at a site with many small units which is analogous to a runback in power on a single larger unit. The SDT does not believe the exceptions written in Requirement R5 unduly compromise reliability.		
Xcel Energy	Yes	We believe the requirement is technically achievable, but question whether the additional cost to design and build plants to meet this goal is the most effective way to spend money to increase grid reliability.
Response: Thank you for your comments.		
Ingleside Cogeneration LP	Yes	In our view, the time frame allotted to accommodate PRC-024-1's frequency and voltage ride-through specifications for new generating facilities is reasonable.
Response: Thank you for your comments.		
GenOn Energy	Yes	Conditionally yes; unconditionally no. It is achievable for any plant with a modern AVR and unit connected auxiliaries. Problems arises for unique circumstances that may require auxiliaries that are not unit connected (directly connected to transmission systems). Existing plants orginally designed with unit connected

Organization	Yes or No	Question 7 Comment
		auxiliaries have been forced to extend auxilary power feeds directly from transmission level voltages.It is believed that transmission system performance better than Attachment 2 is available at the majority of locations, and therefore, it is not necessarily appropriate to make this the design criteria for every future generating station.
Response: Thank you for your comments. Requirement R5 does not apply to existing plants. Part 5.3 of Requirement R5 allows the Generator Owner to design to a less stringent voltage profile (e.g. a profile with faster clearing and faster recovery) if the Transmission Planner can provide the profile for the specific site in question. Attachment 2 provides the outer bounds that may be used by engineers and manufacturers to determine the limits of what they may be required to withstand.		
American Wind Energy Association	Yes	Yes, the feedback we have received from wind turbine manufacturers is that, if such a standard were not applied retroactively and were implemented with a grace period extending at least several years into the future, wind plants would be able to meet these requirements.
Response: Thank you for your comments. The implementation for Requirement R5 is set at six years past approval of the standard. Requirement R5 applies only to "new" plants (as defined in Footnotes 2 and 4) and does not apply retroactively to existing plants.		
Southwest Power Pool Standards Development Team	Yes	
Dominion	Yes	
Imperial Irrigation District (IID)	Yes	
Dynegy	Yes	
Manitoba Hydro	Yes	

Organization	Yes or No	Question 7 Comment
American Transmission Company, LLC	Yes	
Essential Power, LLC	Yes	
FirstEnergy Corp	Yes	
PSEG		We do not know whether new units installed 6+ years out can meet the requirements. We suggest that the team should reach out to OEMs for their input.
Response: Thank you for your comments. One OEM has been participating on the SDT, and the SDT has inquired to other OEM's. In addition, similar grid requirements are already in effect in parts of Europe and Asia. The SDT believes new technology is not required to meet the requirement, but posed the question to determine if industry knew of specific reasons why it cannot be implemented.		
Consolidated Edison Co. of NY, Inc.		Requirement 5.6 suggested wording revieion:Replace "may retroactively grant a temporary exemption" with "may grant a reactoactive temporary exemption"
Response: Thank you for your comments. The SDT agrees and has made the suggested revision.		
Independent Electricity System Operator		We believe this requirement is achievable for most cases. However, provision should be given to the Generator Owners which for specific technical reasons are unable to design a generating unit to comply with the requirements. As worded, R5 does not contain this provision. We therefore suggest that R5 be appended with ", or provide the technical reasons why this is not achieveable" after "the following conditions and exceptions".
Response: Thank you for your comments. The SDT is not aware of technical limitations that would prevent the design and construction of a new generation facility to meet Requirement R5. There are already similar grid requirements in effect in parts of Europe and Asia.		

Organization	Yes or No	Question 7 Comment
Georgia Transmission Corporation		Don't know
Los Angeles Department of Water and Power		LADWP does not have comments on this question at this time.

8. Do you have any other comment, not expressed in questions above, for the GVSDT regarding PRC-024-1?

Summary Consideration: The Effective Date section was modified for Requirements R1, R2, R3, R4, and R6 to reflect a five-year implementation at the request of several stakeholders. The wording in Requirement R1 was revised for clarity, Part 1.1 (rate of change of frequency) was removed and new Parts 1.2 and 1.3 were added for consistency with Requirement R2 at the request of several stakeholders. Minor changes in the wording in Requirement R2 were made to improve clarity at the request of several stakeholders. The structure of Requirement R4 was modified and minor wording changes were made to improve clarity at the request of several stakeholders, though no changes were made to the intent of the requirement. Part 5.1 and Subpart 5.1.1 were incorporated into the body of Requirement R5 so that the remaining Parts of this requirement describe exceptions (i.e. allowances to trip). Minor wording changes were made at the request of multiple stakeholders to clarify wording in Parts 5.1 – 5.6 of Requirement R5. The allowable time to respond to a request for generator protection settings in Requirement R6 was increased from 30 days to 60 days at the request of several stakeholders. The Violation Risk Factors for Requirements R1, R2, and R5 were changed from High to Medium at the request of several stakeholders. Minor wording changes were made to Measures M3, M4, and M5 were made for clarity at the request of several stakeholders. The time frame referenced in Measure M6 was modified to correlate with the change made in Requirement R6. The wording in the Data Retention section was revised at the request of one stakeholder and now reflects the wording used in other recently-approved standards. Minor changes were made in the VSL's for Requirements R1, R2, R3, and R4 to add clarity or correct errors mentioned by several stakeholders. The wording in the Severe VSL for Requirement R5 was revised to add a reference to Parts 5.1 – 5.6 and the tardiness levels in the Requirement R6 VSL's were revised to reflect the change in the requirement. The underfrequency curve for the Western Interconnection and corresponding data table were corrected in Attachment 1 at the request of many stakeholders in the WECC region. Curves for the ERCOT Interconnection and a corresponding data table were added to Attachment 1 at the request of ERCOT. The term "base voltage" was replaced with "nominal operating voltage" in Clarification #1 to Attachment 2 at the request of several stakeholders. Minor wording changes were also made to Clarifications #2, and #5 to better convey the intent of the SDT in response to questions presented by several stakeholders.

Organization	Yes or No	Question 8 Comment
Southern Company		Yes: 1) We respectfully disagree with the SDT's response to our prior comment related to maintaining the safety of the reactor core at nuclear plants for voltage or frequency transients. The intent of our comments is to ensure that application of this standard to nuclear units is coordinated per the requirements of NUC-001.

Organization	Yes or No	Question 8 Comment
		Employing any changes to the grid frequency and voltage ride-through requirements may impact the licensing and design basis of nuclear facilities. NUC-001-1 requires coordination between Nuclear Plant Generator Operators and Transmission Entities for the purpose of ensuring nuclear plant safe operation and shutdown. This is achieved through development of Nuclear Plant Interface Requirements (NPIRs) for each nuclear unit that are based on plant-specific Nuclear Plant Licensing Requirements (NPLRs) and Bulk Electric System requirements that have been mutually agreed to by the Nuclear Plant Generator Operator and the applicable Transmission Entities. The NPLRs are requirements included in the design basis of the nuclear plant and statutorily mandated for the operation of the plant, including nuclear power plant licensing requirements for 1) Off-site power supply to enable safe shutdown of the plant during an electric system or plant event; and 2) Avoiding preventable challenges to nuclear safety as a result of an electric system disturbance or transient condition is important. It is essential that this process be followed closely in attempting to apply any new grid frequency and voltage requirements that are more extreme than those currently addressed in each plant's licensing and design basis. The safety of nuclear power plants is of paramount importance. **The SDT respectfully disagrees that this standard is in conflict with the requirements of NUC-001. Requirement R4.3 of NUC-001 acknowledges that it is not always possible to operate the transmission system to meet the requirements of a particular site's NPIR. The Reliability Coordinator is an applicable entity to the NUC-001 standard, and as such can be involved in granting an exemption (per PRC-024 part 5.6) to any new nuclear facility that cannot meet the ride-through requirements of Requirement R5 because of a conflict with the facility's NPIR if the Reliability Coordinator agrees there is a reliability benefit to allowing the facility to operate with a greater risk of tripping during a frequency or voltage excursion. Existing nuclear facilities can get an exemption from portions of the no trip zones defined in Attachments 1 and 2 through the process defined in Requirement R3 based on the regulatory nuclear safety requirements.** 2) R1, R2, and R3 state "each" non-protection system equipment limitation. This

Organization	Yes or No	Question 8 Comment
		should be clarified to state "each non-protection system equipment limitation associated with the applicable protection function." **The SDT agrees and has removed the term "non-protection system equipment limitation" from Requirements R1, R2, and R3.** 3) Event monitoring equipment required by M5 will be a significant burden on GOs to only prove a negative. We believe M5 should be removed from the standard, because the benefits gained do not justify the costs. **The SDT does not agree that event monitoring equipment poses a significant burden compared to the cost of a new generating unit.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Ameren		(1)Under Applicability it should state that 'all existing generators meeting registry criteria' and also 'new generating units that will meet the registry criteria.' **The SDT feels that the applicable generators owned by a "Generator Owner" is clearly stated in the Registry Criteria and that no further clarification is required.** (2)Please modify the Effective Date and Implementation Plan to provide a five year phase-in to match that of the companion PRC-019-1. Generator voltage protective relaying must be reviewed in both these standards, and we believe that doing so on the same schedule will yield a better coordinated result and less confusion. Each of these standards will consume valuable resource time and the efficiency of reviewing each generator concurrently will improve BES reliability **The SDT agrees and has changed the implementation period, relative to Requirements R1, R2, R3, R4 and R6, of PRC-024-1 to match that of PRC-019.** (3)Please add 'R1, 1.3 If clearing a system fault necessitates disconnecting a generator, then this action is acceptable within the "no trip zone".' This affords the same practical reality recognized for voltage excursions. **The SDT agrees so that there is consistency between Requirements R1 and R2. Part 1.2 has been added in the current revision.**

Organization	Yes or No	Question 8 Comment
		(4)Please be clearer regarding the Voltage Ride-Through curve. Attachment 2 Voltage Ride-Through Curve Clarification #2 could be interpreted to imply that the curve is based on three phase faults. But the inclusion of #5 states that phase-to-ground or phase-to-phase voltages (minimum or maximum as appropriate) are assumed. Of course, for a three phase fault the each phase's voltage is equal. So we interpret #5 to mean that the actual fault type to be simulated should match the Transmission Planning criteria, which for example may be double or single line to ground faults with delayed clearing. We recommend to the GVSDT to align this with the TPL standards, which use three phase fault or single line to ground fault with Normal Clearing, but only single line to ground fault with Delayed Clearing. We would appreciate an example or in depth explanation to tie these together. Please annotate Attachment 2 with references to R2 and clarifications on page 18. **Clarification #2 to Attachment 2 has been modified with an added statement saying "The curves apply to voltage excursions regardless of the type of initiating event." The SDT believes it is not realistic to design generating units to be able to withstand zero voltage at the point of interconnection to the transmission system for extended time periods. None of the other grid standards for generator ride through that the SDT reviewed contain requirements to ride through delayed clearing.** (5)Delete 'or generating plant' from R1, R2, and R3 to be clear that the generating plant auxiliary loads are not subject to these requirements. Alternatively, restate R3 as "...that prevents a generator frequency or voltage protective relay generating unit or generating plant, from meeting the criteria in Requirements R1 or R2 including study results, experience from an actual event, or manufacturer's advisory" to be consistent with R1 and R2. **The SDT agrees and has removed the words "or generating plant" from the Requirements. The wording of R1 and R2 has been changed to indicate that the relaying included in the scope of R1, R2, and R3 are generator voltage relays and generator frequency relays, both of which trip the unit when they operate**. (6)At the end of Requirement R4.2, please add "the Transmission Planner's voltage recovery characteristic from R2 part 2.1.1" since that may well have bearing on the estimate. **Since it is not a requirement for the Transmission Planner to provide the**

Organization	Yes or No	Question 8 Comment
		voltage profile defined in Part 2.1.1. (now Part 2.2), the SDT does not believe it can be required to provide this information in Requirement R4. (7)From our perspective, Requirement R5 doesn't make sense for a newly designed generator. We would suggest the GVSDT to realign M5 to be prospective and to require the GO to provide design basis evidence appropriate for the stage of design of new generators. In early conception stages, the GO would request the Transmission Planner's frequency and voltage excursions. Then the GO would design the generator train and auxiliary system to ride through, and if infeasible, request technical exceptions. Late in the design process the generator frequency and voltage protective trip settings would be determined; it would be appropriate at that time to provide them R6 requests for future system studies. **The SDT appreciates this suggestion, but in discussions with the US regulatory agency regarding this approach, they indicated it could only be used in addition to the performance requirement, not in lieu of performance. The SDT does not believe it would increase grid reliability to require Generator Owners to do both.** (8)For Requirement R6 we oppose providing this specific information to all these functional entities, given that they are getting the R4 estimate of performance during such excursions. **The information would only be given to the entity that requested the information. The number of entities who are allowed to request the information is restricted to those named in Requirement R6. The performance estimate requested in Requirement R4 is different in that it must consider the performance of the entire generating unit including auxiliaries, not just the protection system.** (9)If R6 is retained, please make the following changes: (a) We strongly prefer a reporting of exceptions to the standards frequency and voltage excursion ride-through curves rather than reporting all these relay settings. Use PRC-006-1 Attachment 1 page 28 of that standard for frequency reporting. Develop a similar envelope for voltage reporting. If a Transmission Planner's voltage recovery characteristic allowed for in R2 part 2.1.1 differs that should be provided for the

Organization	Yes or No	Question 8 Comment
		generators in their area. Generator Owners would then report exceptions. (b)Insert “frequency and voltage” between generator and protection in the first line.(c)Delete “and within 30 calendar days of any change to those trip settings,” because this creates an open ended obligation on the GO. **The SDT assumes that the requestor would only ask for settings for the protection functions that are modeled for stability or UFLS performance. Typically, most generator protection functions are not included in these models. However, in order to predict the generators’ behavior accurately, the entity creating the model must know the settings for all of the modeled protection functions, not just those that do not meet Requirements R1 or R2. Following such a request only changes to the settings that have been requested would need to be reported. The SDT has added the words “…unless otherwise directed” so that the requestor can indicate that future changes do not have to be reported (as may be the case for a one-time study that will not be repeated).** (10)We would suggest the GVSDT to not capitalize frequency and voltage excursions as they are no longer defined terms. **The SDT agrees and has made the suggested changes.** (11)We suggest the GVSDT to replace the time-based or binary VSL for R1, R2, R3, R4 and R6 with a VSL in terms of the GO % of MWh produced for the time period of violation. This better characterizes the risk to BES reliability. We propose <5% for Lower, 5 to 10% for Moderate, 10 to 15% for High, and >15% for Severe. As presently proposed a generator with no operating hours could cause a GO to incur a Severe violation though it posed no risk to the BES. **The SDT discussed this approach with NERC earlier in the drafting process and was told it is not an acceptable method of structuring a VSL.** (12)From our perspective, the VSL for R5 doesn’t make sense for a newly designed generator. We suggest, a time-based VSL with x days late in providing R4 or R6 type information. . In this regard, we propose to the GVSDT 30 days late for Lower, 31 to 60 days late for Moderate, 61 to 90 days late for High, and >90 days for Severe. **The**

Organization	Yes or No	Question 8 Comment
		SDT does not see how a tardiness structure would apply to a performance requirement. (13)PRC-024-1, R2.1 states that generator terminal voltage refers to Attachment 2. However, in R2 itself, footnote 3 states that voltage excursion applies to point of interconnection, meaning the GSU high-side. We suggest the SDT resolve this discrepancy. **Requirement R2, part 2.1 states that Attachment 2 applies to conditions on the transmission system when the generator is operating within 95% to 105% of its rated voltage. The SDT does not see a discrepancy.** (14)Attachment 2 should include footnote similar to footnote 3 provided for R2. **The SDT does not believe it is necessary to insert duplicate footnotes.**
Response: Thank you for your comments. Please see the responses to individual comments above.		
Pepco Holdings Inc. & Affiliates		1) If it is critical to the reliability of the BES to not have generators trip off line for voltage excursions associated with close in three phase faults, then it is equally as important to have them remain on-line for single line to ground faults, which are much more common. During a phase to ground fault at the point of interconnection the faulted phase voltage collapses to zero but the unfaulted RMS phase to ground voltages could rise as high as 80% of the RMS line to line voltage for an effectively grounded system (with a coefficient of grounding = 80%). This is well in excess of the 1.2 p.u. overvoltage requirement presently shown in Attachment 2. As such, for the unit to ride through phase to ground faults at the point of interconnection then the short time 1.2 p.u. overvoltage threshold at the point of interconnection needs to be raised above 0.8 x 1.73 = 1.38 p.u.. In summary, the overvoltage portion of the curve in Attachment 2 should be modified to require the unit to stay connected with a 138% phase to ground overvoltage appearing at the point of interconnection for up to the expected clearing time of a Zone 1 phase to ground fault. **The SDT agrees that the phase to ground voltage can rise to the level noted in your comment during single phase to ground faults. The SDT has modified Clarification #5 to remove the words "…phase to ground…" If only the phase-to-phase voltages are evaluated,**

Organization	Yes or No	Question 8 Comment
		then the limit can remain at 1.2 p.u. voltage. 2) The standard should make clear whether the no-trip zone shown in Attachments 1 and 2 includes the boundary curves themselves. **There is a text box in the middle of the graph that specifically states that the no trip zone does not include the lines. The SDT does not believe any further explanation is necessary.** 3) To add clarity and avoid confusion, the ordinate of the graph in Attachment 2 should be labeled Per-unit RMS Voltage Measured at the Point of Interconnection. **Clarification #5 to Attachment 2 has been modified to include the term "RMS."** 4) The current language in Item #1 of the "Voltage Ride-Through Curve Clarifications," which appears on the last page of the standard, may cause problems for generator interconnections on the 500kV system. Most transmission Planners use "nominal" transmission system voltage levels as the "base voltage" in their system models. These are the same "nominal" system voltages specified in ANSI C84.1. In most cases, C84.1 shows the maximum allowable system voltage as 105% of nominal, with the exception of 500kV. For 500kV systems the maximum system voltage is 550kV, and it is routine to operate the transmission system above 525kV (105% of nominal). If the "base voltage" at the point of interconnection used in planning studies is 500kV but the system is normally operated above 105%, then the generation protective systems must be capable of maintaining operation with the continuous voltage at the point of interconnection above 105% of "nominal" (at least for 500kV systems). This being the case the voltage base in Attachment 2 for 500kV systems will by necessity have to be something other the "nominal base voltage" used by the Transmission Planner in their system models. Perhaps this could be addressed by re-wording Item #1 to read "1. The per unit voltage base for these curves is to be specified by the Transmission Planner at the point of interconnection to the Bulk Electric System (BES)." By removing the reference to "the base voltage used in the system models by the Transmission Planner" it eliminates the conflict mentioned above. On the other hand it now requires the Transmission Planner to provide this "other than nominal base voltage for 500kV systems" to the Generator Owners. **Since some 500**

Organization	Yes or No	Question 8 Comment
		kV systems may not operate in the same manner as yours, the SDT would prefer not to specify different ranges for particular voltage classes. In order to address your concern, the SDT has modified Clarification #1 to Attachment 2 by removing the words “base voltage” and “in the system models” and has replaced them with “nominal operating voltage specified by the Transmission Planner.” The SDT believes this will address the different operating criteria used in different regions. 5) The word “crest” should be removed from Item #5 of the “Voltage Ride-Through Curve Clarifications,” which appears on the last page of the standard . The voltages referred to in this standard are all per-unit “RMS” voltages, not “peak” or “crest” voltages. **The word “crest” is necessary for equipment manufacturers to know what the limits are that they must meet in designing equipment to meet the requirements of this standard. Under normal operating conditions per unit crest and per unit RMS are the same, but during high voltage excursions, magnetic saturation creates differences.** 6) Typically unit connected generator protection packages, which include frequency and voltage protective elements, are supplied by voltage transformers connected on the terminals of the generator rather than on the high side of the generator step-up (GSU) transformer. For frequency elements, the frequency at the terminals of the generator is the same as on the high side of the GSU transformer. So comparison of frequency protective element set points can be made directly with Attachment 1. However, this is not true for voltage. The generator terminal voltage could be higher, or lower, than the system voltage on the high side of the GSU transformer depending on the voltage drop across the transformer, which varies depending on the generator real power output and whether the generator is supplying or absorbing reactive power. Since this standard requires the generation to remain connected for specific voltage criteria as measured at the point of interconnection, but the voltage sensing protection is connected to the generator terminals, some technical guidance (with specific examples) must be provided to allow the Generator Owner to properly translate these voltage criteria to the voltages seen by the protective relays on the terminals of the generator. Otherwise an incorrect evaluation may result. It is

Organization	Yes or No	Question 8 Comment
		recommended that a Technical Reference Document similar to the "Power Plant and Transmission System Protection Coordination" document developed by the NERC System Protection and Control Subcommittee be produced, or the above mentioned document revised, to provide illustrative examples of how to apply the Attachment 2 POI voltage criteria to voltage sensing protective elements connected to the terminals of the generator. **There are text books that cover the necessary calculations. Clarification #6 to Attachment 2 provides guidance to the conditions to be used when doing the evaluation.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Texas Reliability Entity		1) Purpose Statement: If we correctly understand the intent, the second comma should be removed. **The SDT agrees and has removed the comma.** 2) Does the SDT want to consider any specific requirements regarding generators that are connected as synchronous condensers, and is it the intent of the standard to cover this operating mode? **The SDT considered including synchronous condensers as applicable facilities for this standard. The SDT determined that it is not necessary to include synchronous condensers because frequency transients within the scope of this standard are not a serious concern for synchronous condensers, and most synchronous condensers do not have the auxiliary systems that would cause a condenser to trip under the voltage transients defined in this standard.** 3) All requirements: Need to clarify the phrase "generating unit or generating plant". Does the "generating plant" phrase imply that the frequency and voltage setting criteria also applies to plant auxiliary equipment (referenced in R4)? In ERCOT, we have seen multiple instances where close-in faults have created low voltage conditions which caused auxiliary equipment to trip (boiler feed pumps, baghouse fans, etc.) which in turn caused a unit runback and trip. If the intent of this standard is to also cover plant auxiliary equipment, then this needs to be very clearly stated in the Applicability section and/or in the Requirements. **The SDT agrees and has removed the words "or generating plant" from the Requirements. The wording of**

Organization	Yes or No	Question 8 Comment
		R1 and R2 has been changed to indicate that the relaying included in the scope of R1, R2, and R3 are generator voltage relays and generator frequency relays, both of which trip the unit when they operate. 4) R1 and R2: The SDT may want to consider adding Volts per Hertz criteria. For example: ERCOT region criteria currently states a generator must remain connected if Volts/Hertz is less than 105% of generator design voltage and frequency, and also if Volts/Hertz is less than 116% of generator design voltage and frequency for less than 1.5 seconds. **The V/Hz relaying applicability is addressed in Footnote 1. R1 and R2 apply to situations where a unit is tripped by generator frequency relaying or voltage relaying.** 5) R1: Need to add “or generating plant” to end of R1. **The SDT has removed the words “or generating plant” from Requirements R1 and R2 at the suggestion of other commenters, so it is no longer necessary to add it to the end of Requirement R1 for consistency.** 6) R2: Need to specify that the undervoltage “no trip zone” applies to both single-phase and three-phase voltage excursions. **Clarification #2 to Attachment 2 has been modified with an added statement saying, “The curves apply to voltage excursions regardless of the type of initiating event.”** 7) R2.1.2 and 2.1.3 need to include the phrase “generating unit or generating plant” versus “generator” to be inclusive of a plant site and provide consistency throughout Standard. **The SDT agrees. The standard has been revised to use the words “generating unit.”** 8) R1 and R2 Exclusions: The SDT may want to consider these additional exclusions: a. A generating unit may trip by frequency or voltage protection while a unit is being brought on or off-line, if the trip does not result in the loss of generation to the system.b. A generation unit may trip by frequency or voltage protection if the unit is being operated below its Low Sustained Limit (LSL), where LSL is defined as the limit established by the Generator Operator that describes the minimum sustained energy

Organization	Yes or No	Question 8 Comment
		production capability of the generator.c. A generator unit may trip by frequency or voltage protection if the unit is being operated in a "Test" status and is not under AGC control. **The SDT disagrees that these exclusions are needed in Requirements R1 and R2. These two requirements specify how generator protection is to be set, which does not change for different operating conditions. There are similar exceptions written into Requirement R5, which is a performance requirement, to cover these situations for plants designed and built after the standard is approved and this requirement is implemented.** 9) R3: Generator Operators should be required to document "known" equipment limitations. There are probably many examples of unknown equipment limitations, simply because a plant may not have experienced a fault condition that could expose the limitation. Also need to clearly state if this requirement (i.e. due to the phrase "generating plant") also applies to plant auxiliary equipment, which would require the GO to provide extensive review and documentation on all of their plant auxiliary systems as well. **The SDT agrees and has added the word "known" to Requirement R3.** 10) R5: Need to clearly state if this requirement applies to plant auxiliary equipment. **The SDT agrees and has added "(including auxiliary systems)" to Requirement R5.** 11) In 5.2, insert "nameplate" after "aggregate" to be consistent with R5.1.1. **The SDT agrees and has added the word "nameplate," as suggested.** 12) R5 Exceptions: The SDT may want to consider these additional exceptions: (a) A generating unit may trip by frequency or voltage protection while a unit is being brought on or off-line, if the trip does not result in the loss of generation to the system. (b) A generator unit may trip by frequency or voltage protection if the unit is being operated in a "Test" status and is not under AGC control. **The SDT believes that the first suggested exception is already covered under part 5.1 (now part of the main body of the requirement). The SDT is not sure why AGC status is of issue since many base loaded units do not run on AGC, but if it would cause certain units to become unstable during an excursion such that it was about to lose synchronism,**

Organization	Yes or No	Question 8 Comment
		then part 5.6 would apply. 13) In Measures M1 and M2: See comment 3 above regarding the use of the phrase "generating plant". Is it the intent of these measures to also cover frequency and voltage setting sheets for plant auxiliary equipment protection systems? **No. Requirement R1 specifically says, "generator frequency protective relaying" and Requirement R2 specifically says, "generator voltage protective relaying." The auxiliary equipment protection systems are not in the scope of these requirements.** 14) In Requirement R4, Measures M4 and M5, and some VSLs: Remove capitalization of "Frequency/Voltage Excursions" and similar terms (e.g. Frequency Excursion), which are not formally defined in this standard nor in the NERC glossary. **The capitalization has been removed as suggested.** 15) VSLs for R1, R2, and R3: What is the SDT's intent regarding a GO that has set its relays per R1 and R2, and has no documented equipment limitations per R3, but still experiences a unit trip within the one of the "no trip" zones in Attachment 1? Is that intended to be a violation of this standard? There is not a VSL for this situation. The VSL for R5 contemplates a violation for tripping in the no-trip zone, but it only covers "new" generation units, and there is not a similar VSL for existing units. **For existing generating units, a trip during a frequency or voltage excursion for reasons other than operation of the generator protection is *not* a violation. For that reason, it is not covered in the VSL's. Requirement R5 is only applicable to "new" units (as defined in the standard). The standard does not contain an equivalent performance requirement for "existing" units, hence there is no such VSL.** 16) VSL for R1 and R2: The term "technical" should be replaced with "equipment" to be consistent with the Requirements. Need to replace "generator" with "generating unit or generating plant" to be consistent with the Requirements. **The SDT agrees that the word "technical" should be replaced with "equipment" and has made the suggested revision. The word "generator" has been replaced with "generating unit" since that wording is now used in Requirements R1 and R2.**

Organization	Yes or No	Question 8 Comment
		17) VSL for R2: Language should be similar to VSL for R1 with respect to "activated to trip" phrase and to be consistent with the Requirement itself. Suggest replacing "conditions" with "criteria" to be consistent with VSL for R1. **The SDT agrees and has changed the wording in the VSL for Requirement R2 as suggested.** 18) VSL for R3 and R4: What VSL applies if the communication occurs on day 61? It looks like the answer is "none." **The SDT agrees and has revised the number used in the Severe level of the VSL accordingly.** 19) VSL for R3: See comment 9 regarding requirement R3 above. The requirement and VSL should only apply to "known" equipment limitations. **The SDT agrees and has added the word "known" to the VSL.** 20) VSL for R4: Consider changing "unit's performance" to "unit's or plant's performance." **The wording in Requirement R4 refers to "generating unit" so the SDT did not change the wording in the associated VSL.** 21) VSL for R6: Remove the phrase "or limitations," because R3 discusses limitations and the reporting thereof and it is out of place here. **The SDT agrees and has removed the words "or limitations" from the VSL** 22) Attachment 1- Change "Texas Interconnection" to "ERCOT Interconnection". **The labels on Attachment 1 and the associated data tables have been changed as suggested.** 23) Regarding the Voltage Ride-Through Curve Clarifications: The reference to a generation facility's "point of interconnection to the Bulk Electric System" is incorrect, because the generation facility is itself part of the BES. We assume this is intended to refer to the point of interconnection between the generation facility and the transmission facility, and the text should be modified accordingly. **The SDT appreciates your position, but declines to change the wording because other commenters have expressed concern when the term Bulk Electric System is not used.**

Organization	Yes or No	Question 8 Comment
Response: Thank you for your comments. Please see the responses to your specific comments above.		
PacifiCorp	Negative	1. PacifiCorp does not support the addition of the term "bulk power system" to Section 4.2.2.1 of the "Applicability" section. The term is ambiguous and, in this context, fails to provide the clarity afforded by either the previous language ("at greater than or equal to 100 kV") or the defined term of "Bulk Electric System." PacifiCorp suggests maintaining the existing applicability language, including the "directly connected" qualifier so that the sentence reads as follows: "Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected to the point of interconnection at greater than or equal to 100 kV." **It appears to the SDT that this comment refers to MOD-026, not PRC-024. Please see the response provided to this same comment in Question 5.** 2. PacifiCorp believes that the second bullet under Section 4.2.2.2 of the "Applicability" section introduces confusion for registered entities. If we correctly understand the intent of the GVSDT, then please consider the following language to replace the two existing bullets: o "Each individual generating unit greater than 20 MVA (gross nameplate rating), plus an aggregate model for the other generating units of less than 20 MVA at the plant/Facility; and o Where there are no individual generating units greater than 20 MVA in a plant/Facility with total generation greater than 75 MVA (gross aggregate rating), an aggregate model for the generating units of less than 20 MVA." **It appears to the SDT that this comment refers to MOD-026, not PRC-024. Please see the response provided to this same comment in Question 5.** 3. PacifiCorp agrees that the addition of sub-Requirement 2.2 is a good clarification, but believe that the language could be further clarified to remove unnecessary confusion by amending the sub-Requirement as follows: "For generating plants/Facilities with total generation greater than the thresholds established in the Applicability section of this standard that are comprised of units that have gross nameplate rating of less than 20 MVA, each Generator Owner shall perform its verification using plant aggregate model(s) that include the information required by

Organization	Yes or No	Question 8 Comment
		Requirement sub-parts 2.1.1 through 2.1.6." **It appears to the SDT that this comment refers to MOD-026, not PRC-024. Please see the response provided to this same comment in Question 5.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Luminant Power		1. Requirement R1 and R2 discuss generator frequency and voltage relaying to be set such that they do not trip within the "no trip zone" of Attachement 1 and 2 respectively. Luminant believes that these requirements should only apply to relays that use frequency or voltage sensing only. Impedance, and voltage controlled over-current relays should not be included since they are part of the Generator Loadability and AVR Control standards. Relays using both voltage and frequency should not be part of the standard. Alternately, if volts per hertz relays are included, Luminant recommends that an additional requirement R2.2 be added to take in consideration volts per hertz relays. R2.2 would become "Generator volts per hertz relaying shall not cause a unit trip for conditions that are less than 116% of generator rated design voltage and frequency and last for less than 1.5 seconds." For footnote 1, individual curves would have to be listed for each protective relay function, as the Attachement 1 curve is for voltage relays only. **The SDT feels that the list of relaying included in Footnote 1 needs to be considered in the scope of this standard, as they will be just as effective as voltage only and frequency only relays in tripping the unit during frequency or voltage excursions described by Attachments 1 and 2. V/Hz characteristics from applicable IEEE standards were considered. Clarification #4 to Attachment 2 states: "The curves depicted assume system frequency is 60 Hertz. Adjust the magnitude of the high voltage curve in proportion to deviations of frequency below normal."** 2. R3 is an administrative requirement that provides little or no benefit to the BES. Luminant recommends that the requirement be removed, and Requirements R1 and R2 should be modified to delete the reference to R3 as follows; " ... unless the generator owner has identified an equipment limitation ..." **The SDT agrees that Requirement R3 is basically administrative, but ensures the limitations (and associated changes in**

Organization	Yes or No	Question 8 Comment
		protection settings that affect the performance of a generating unit during a frequency or voltage excursion) are communicated to the appropriate planning and operating entities so that its performance can be correctly modeled. 3. R6 should be at a minimum of 90 days due to some entities have a large number of generating units. **The SDT agrees that an increase in the amount of time allowed for response is warranted. The SDT has changed the time period from 30 days to 60 days.** 4. Overall, this standard should address voltage and frequency relay settings only. **The SDT is charged with implementing the reliability improvement recommendations from FERC Order 693 and the 2003 Northeast Blackout Report which requires that the standard address performance.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Luminant Energy		1. Requirement R1 and R2 discuss generator frequency and voltage relaying to be set such that they do not trip within the “no trip zone” of Attachement 1 and 2 respectively. Luminant believes that these requirements should only apply to relays that use frequency or voltage sensing only. Impedance, and voltage controlled over-current relays should not be included since they are part of the Generator Loadability and AVR Control standards. Relays using both voltage and frequency should not be part of the standard. Alternately, if volts per hertz relays are included, Luminant recommends that an additional requirement R2.2 be added to take in consideration volts per hertz relays. R2.2 would become “Generator volts per hertz relaying shall not cause a unit trip for conditions that are less than 116% of generator rated design voltage and frequency and last for less than 1.5 seconds.” For footnote 1, individual curves would have to be listed for each protective relay function, as the Attachement 1 curve is for voltage relays only. **The SDT feels that the list of relaying included in Footnote 1 needs to be considered in the scope of this standard as they will be just as effective as voltage only and frequency only relays in tripping the unit during frequency or voltage excursions described by Attachments 1 and 2. V/Hz characteristics from applicable IEEE**

Organization	Yes or No	Question 8 Comment
		standards were considered. Clarification #4 to Attachment 2 states: "The curves depicted assume system frequency is 60 Hertz. Adjust the magnitude of the high voltage curve in proportion to deviations of frequency below normal." 2. R3 is an administrative requirement that provides little or no benefit to the BES. Luminant recommends that the requirement be removed, and Requirements R1 and R2 should be modified to delete the reference to R3 as follows; " ... unless the generator owner has identified an equipment limitation ..." **The SDT agrees that Requirement R3 is basically administrative, but ensures the limitations (and associated changes in protection settings that affect the performance of a generating unit during a frequency or voltage excursion) are communicated to the appropriate planning and operating entities so that its performance can be correctly modeled.** 3. R6 should be at a minimum of 90 days due to some entities have a large number of generating units. **The SDT agrees that an increase in the amount of time allowed for response is warranted. The SDT has changed the time period from 30 days to 60 days.** 4. Overall, this standard should address voltage and frequency relay settings only. **The SDT is charged with implementing the reliability improvement recommendations from FERC Order 693 and the 2003 Northeast Blackout Report which requires that the standard address performance.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
We Energies		a. Most generator voltage relaying is supplied from generator voltage transformers on the low-voltage side of the generator step-up transformer (GSU). It is necessary to provide the information needed for the Generator Owner to relate relay settings on the low-side of the GSU to the No Trip characteristic in Attachment 2, which is based on voltages on the GSU high-side. **The SDT agrees that generator protection normally senses the voltage at the generator terminals. Because there are many**

Organization	Yes or No	Question 8 Comment
		configurations of the connections of the generators to the transmission systems, it is not practical to develop a single voltage curve defined at the generator terminals that equates to the voltage caused by an event on the transmission system. Each Generator Owner will have to determine how the transmission system event affects his specific generating units. This approach is consistent with FERC Order 661-A and other international grid standards that are in effect. b. In Attachment 2, please clarify whether the No Trip zone includes the lines, similar to what was done in Attachment 1. **The no trip zone as depicted on the graph does include the lines (it is not permissible to trip if the voltage at the POI reaches 0.0 pu or if the continuous operating voltage is at 0.95 pu or 1.05 pu). The SDT expects that protection settings will be calculated to provide some margin from the absolute numbers on the curve (translated appropriately to the generator voltage level that the protection senses).**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
PPL Electric Utilities and PPL Supply NERC Registered Organizations		a. A standard-specific definition of the word "plant" is needed, restricting applicability to NERC-registered generators. A plant consisting of two 750 MW fossil units and a standby 10 MW diesel generator, for example, should not have to model the diesel unit's behavior. **Individual generators and plants are not "registered" with NERC. The Applicability section states that the standard is applicable to Generator Owners. As such, all generating facilities that fall within the definition of the Registry Criteria fall within the scope of this standard.** b. Clarity is needed for the expression, "it does not trip," in R1 and R2. Does this mean that the protective relaying does not trip, or that the unit does not trip? In the latter case do the requirements pertain only to interlocks, or do they also cover disturbances that may result in a trip? Such differentiations were clearly spelled-out in the PRC-005-2 draft currently out for voting, and they are needed here also. What seems at first to be relay-setting requirements may in fact also incorporate aux equipment drop-out, invoking for existing equipment the concerns stated above in

Organization	Yes or No	Question 8 Comment
		response to question 7 (with regard to designing a standard based on a technology for which vendors may not guaranty performance). **The wording of R1 (and R2) has been modified and, hopefully, clarifies the intent. The intention is that the relaying operate to trip the unit only when conditions are such that the frequency vs time characteristic (or voltage in R2) presented to the relay are described by the area outside of the "no trip zone" of Attachment 1 (2 for R2). It does not matter if the protection trips the generator directly or through a lockout relay or other auxiliary device.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Independent Electricity System Operator		a. Requirement R1: We believe the words "or generating plant" are missing at the end of R1 since the requirement addresses frequency protection relay settings for new or existing generating unit and generating plant. **The SDT has removed the words "or generating plant" from all of Requirement R1 for consistency in wording.** b. Requirement 4: In the last posting, we commented that:"We do not support the requirement to provide an estimate of the performance of the units during frequency and voltage excursions. First of all, the requirement does not distinguish whether it applies to units that are equipped with frequency/voltage protective relays or otherwise. Secondly, the intent of providing the suggested estimate is to allow Transmission Planners to apply valid or supported assumptions in their planning studies. Given the requirements in Attachments 1 and 2, and Requirement R3, the TPs can apply the following relevant assumptions: (i) For units that are equipped with frequency/voltage protective relays, the GO's submitted relay settings will determine when the units will trip; (ii) For units that are NOT equipped with frequency/voltage protective relays, the units are conservatively assumed to trip when the simulated frequency/voltage goes outside the bounds of Attachments 1 and 2. We do not see what other estimates that can be more relevant and valid than the above. We see that there may be some value in providing these estimates but only in the case of generators not equipped with frequency/voltage protective relays where tripping

Organization	Yes or No	Question 8 Comment
		takes place beyond the no-trip zones of Attachments 1 and 2. For this information to be useful however, the generator's behavior must be predictable. While it may facilitate some "what-if" analysis, it is not clear that using this information would be better than the conservative assumption "b" above. How does the SDT envisage that the Transmission Planner will use this additional information if it cannot be relied upon? The SDT responded that "The "estimate of performance in 25% increments" portion of the requirement has been removed. The SDT agrees that it would not improve reliability." We do not agree that removing the 20% increment part goes far enough to achieve a good quality standard. In our view, based in argument put forth in our previous comments, the whole requirement does not add any value to reliability. We again suggest the SDT to remove this requirement altogether." **The SDT appreciates your position but was charged with meeting the recommendations of FERC Order 693 and the 2003 Blackout Report. Requirement R4 attempts to address a portion of the recommendation to provide better information to Transmission Planners regarding the performance of generating facilities during frequency and voltage excursions. This requirement is written such that the information is only provided if it requested by a planner. If the planner does not believe the information received would be of any value, it is permissible to not make the request.** c. Requirement R4.1, last sentence "If the Generator Owner expects the existing unit, generating plant will remain connected.....". We believe the "," before "generating plant" should read "or". **The SDT agrees that the wording was incorrect. Requirement R4 has been significantly modified and the intent of Parts 4.1 and 4.2 incorporated into the body of the requirement.** d. The proposed implementation plan for both standards conflicts with Ontario regulatory practice respecting the effective date of implementing approved standards. It is suggested that this conflict be removed by appending to each of the sentences in Section A5, after "following applicable regulatory approval", of the two standards to the following effect:", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities." **The phrase "following**

Organization	Yes or No	Question 8 Comment
		applicable regulatory authority" includes regulatory bodies from Canadian provinces requiring regulatory body approval. For clarity, the SDT modified the Implementation section and expanded the implementation description to more clearly show effective dates for those areas requiring regulatory approval and those areas that do not require regulatory approval.
Response: Thank you for your comments. Please see the responses to your specific comments above.		
American Transmission Company, LLC		ATC recommends the SDT give consideration to the following:1. In Requirements R2 - the text refers to "non-protection system equipment" but this terminology is not defined. ATC recommends that the SDT provide some definition/description and perhaps a list of this type of equipment in a footnote to improve clarity. **The SDT agrees that this term was confusing. The term has been removed from Requirement R2 and the wording in Requirement R3 has been modified to more clearly indicate that limitations of the protection system do not qualify as a reason for exemption from portions of the no trip zones defined in Attachments 1 and 2.** 2. In Requirements, R3 - ATC recommends that the SDT add the requirement that the GO provides the expected duration of the limitation, if it is known. **In general, the SDT believes these limitations are permanent due to equipment design or regulatory considerations. The Reliability Coordinator, Planning Coordinator, Transmission Operator, or Transmission Planner may certainly inquire if they believe the Generator Owner is describing a temporary limitation.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
ACES Power Marketing Standards Collaborators		Because NERC has made clear that standards are enforced against the BPS and not the BES, the applicability section should be modified to state clearly that it applies to Facilities that are part of the BES. Otherwise small generators that do not affect reliability could be impacted by these standards. NERC enforcement has made this clear in response to comments on CAN-0016 that the CIP-001 standard applied only to the BES. They stated clearly: "According to Section 39 of the Energy Policy Act of

Organization	Yes or No	Question 8 Comment
		2005, NERC defines the Interconnected Power Grid as the Bulk Power System. Unless otherwise restricted by a standard, it is applicable to the BPS." **There is no mention of either BPS or BES in the Applicability section of this standard. The term "Bulk Electric System" is used within the Clarifications to Attachment 2.** Use of "new or existing" as a description for the generators in Requirements R1, R2 and R5 is confusing. What exactly constitutes new and why is it relevant? The requirements are performance requirements that apply to in-service generators so how does new help explain this further? The footnote in Requirement R5 only further confuses the situation since it is not included in Requirements R1 and R2. Part of the confusion likely centers around Requirement R5 applying to maintaining new generators frequency and voltage excursion performance as well as designing and building it. If "maintain" was removed from Requirement R5, we believe "new" could be removed from Requirement R1 and R2 and they essentially become the maintenance requirements. **The SDT agrees and has removed the words "new or existing" from both R1 and R2 and has revised Footnote 4 in Requirement R5** Furthermore, "new and existing" is not used consistently within other requirements such as Requirement R4. It is not obvious why it would not apply to Requirement R4 it if applies to Requirements R1 and R2. **The words "new and existing" were not used in Requirement R4. This requirement applies only to "existing" units because "new" units are expected to perform per Requirement R5.** Neither Requirement R1 nor R2 state within the main body of the requirement that the Parts are intended to be exceptions to the requirement. For clarity, there should be a statement (i.e. except when the Parts 1.1 and 1.2 are met) within the requirement that makes this clear. **The SDT agrees and has added wording identical to that in Requirement R2 to clarify that the sub parts are intended to be exceptions.** For Requirements R1 and R2, it is not clear if the sub-parts are the only reasons that allow for exceptions if other equipment limitations exceptions are allowed. Other equipment limitations should be allowed, and these requirements should be clarified to allow them. **It is stated in both Requirements R1 and R2 that equipment**

Organization	Yes or No	Question 8 Comment
		limitations (documented and communicated per Requirement R3) will allow tripping within portions of the no trip zones in Attachments 1 and 2. These statements have been moved into the sub parts of the two requirements for clarity. As written, Requirement R5 appears to be assumed to apply to a new generator in perpetuity. We draw this conclusion from the inclusion of "maintain" in the requirement. We think it makes more sense to have this requirement apply only to designing and building a new unit and then have the requirements that apply to existing units apply to the maintenance of the new units once they are established. The standard does not appear to allow "new" generating units to have frequency and voltage excursion performance limited by equipment. It should allow "new" equipment as it experiences normal wear and tear as well as damage for any other reasons to document its equipment limited frequency and voltage performance and communicate it similar to Requirements R1 through R3. Otherwise, a Geneator Operator with a "new" generator that has damaged equipment will be forced between operating the unit in a limited manner providing reliability support to the BES and possibly in violation of this standard or taking a forced outage to avoid violating the standard and experiencing escalated penalties for knowingly violating the standard. **The intent of Requirement R5 is to apply to "new" plants in perpetuity as you have described. If equipment aging or other conditions develop that clearly limit the generating plant's ability to ride through excursions and the owner is faced with performing maintenance that would not otherwise be needed in order to regain ride-through performance, Part 5.5 allows the Reliability Coordinator to grant an exemption if the RC believes the reliability improvement from having the generator operating or available outweighs the risk that it may not ride through an excursion.** We do not believe that Reliability Coordinator is the proper entity to grant a temporary exemption in Part 5.6. Rather, it is the Planning Coordinator that should grant the exemption. Furthermore, this is not consistent with other requirements such as Parts 2.1 and 2.1.1 that specify the Transmission Planner grant the exemption. Of course, Part 5.6 would not be necessary if Requirement R5 did not

Organization	Yes or No	Question 8 Comment
		deal with maintaining the unit and allowed the other requirements that apply to existing units to address maintenance. **It is the Reliability Coordinator that is responsible for the reliability of the transmission system, not the Planning Coordinator.** We do not believe the VRFs for Requirements R1, R2 and R5 warrant High VRFs. The BES is already operated within each BA and TOP for the loss of a single unit. Tripping of a generator due to a frequency or voltage excursion is an uncommon event that is already planned for. It is highly unlikely that tripping of such a generator or even several generators will lead to instability, system separation or cascading which is required for the VRF to be High. Furthermore, by setting the VRF to High, this increases the potential that every single unit outage could become subject to a Compliance Violation Investigation which is simply not necessary. **The SDT agrees and has changed the VRF's for these three requirements to Medium.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
ERCOT		Comment 1: In the Applicability section, it is not clear in 4.2.3.2 which units/plants are required to meet this standard. For example, a generating plant that is greater than 75 MVA and consisted of 75 1MW generating units, is this generating plant required to meet MOD-026-1? Another example, a generating plant that is greater than 75 MVA and consisted of one 45MVA generating unit and two 15MVA generating unit, is only the 45MVA generating unit required to meet MOD-026-1?
Response: Thank you for your comments. Your comment refers to MOD-026. The SDT has refined Section 4.2.2 of the MOD-026 standard applicability to clarify that all units in a plant that meet the applicability are to be verified. Units that are less than 20 MVA can be verified utilizing either individual or aggregate model(s)		
Georgia Transmission Corporation		Comment on R6, Severe VSL.Time limit is within 60 calendar days, however the time limit for R3, R4 and R5 state 61 calendar days.Wording for Severe VSL for R3, R4, R5 and R6 should have the same time limitations of either "...within 61 calendar days" or revised so that the documentation was"communicated greater than 60 calendar

Organization	Yes or No	Question 8 Comment
		days....”.
Response: Thank you for your comments. The SDT agrees. The Severe VSL for Requirement R6 has been revised to address the issue you presented.		
Ingleside Cogeneration LP		Ingleside Cogeneration LP fully supports the goal to standardize voltage and frequency ride-through settings. In addition, we recognize the benefit to provide accurate generator modeling information and perform regular performance validations to system planners. However, such activities come at a price and compete for the same resources needed to support BES reliability in other ways.Furthermore, there is a cost to develop new PRC-024-1 compliant generation technologies - or to harden existing ones. This may improve reliability over the longer term, but could delay or even rule out the deployment of promising capabilities early on. These are all considerations that we know that the project team is aware of, but we will continue to point out the hidden costs of compliance wherever we believe that a justification of its advantages is not immediately obvious.
Response: Thank you for your comments. The SDT agrees that designing, building, and maintaining a generating facility to meet the performance requirement of Requirement R5 will be more expensive than building one without that capability. For this reason, the SDT is limiting the scope of the requirement to new facilities, with a six-year implementation schedule to allow designs to be developed, and is not requiring existing generating facilities to have to redesign and rebuild to accomplish the same level of performance.		
ISO New England Inc		ISO New England has comments on Requirement R2 and R3:R2Although the time duration is acceptable ISO-NE does not agree with the band shown. The band is shown as 0.95 p.u to 1.05 p.u at the point of interconnection. Parts of the New England system have not been designed to maintain steady state operation within this band. The band needs to be expanded to 0.90 pu to 1.05 pu. We also believe there are a number of other parts of the system outside of New England which would have similar concerns. Failure to make this change means that it is acceptable for generators to trip during steady state operation of the system on “low” voltage.

Organization	Yes or No	Question 8 Comment
		Unanticipated tripping of generators under steady state conditions could lead to significant reliability concerns on the system. **The voltage band applies to the point of interconnection of an operating generator. Other portions of a transmission system may be at significantly different voltages, but that would not give the generator an excuse to trip. If it is necessary to have an expanded band of normal operating voltage for a particular region, it can be mandated through a regional standard without imposing the same requirements on the entire continent.** R3The ISO would like to reiterate its previous comment that R3 is a significant concern. In the event that a generator has a piece of equipment which prevents it from meeting the requirements of R1 and R2, such as a motor contactor which drops out on voltages in the "No Trip Zone", there is no requirement to correct the issue. Instead, the generator must only document the limitation. This completely undermines the intent of this standard. There is no point to setting undervoltage relays to meet the curve if other equipment is still going to trip the plant. This standard appears to simply documenting system concerns rather than identifying and correcting them. **Requirements R1 and R2 apply to generator protection, not to the auxiliary systems. An "existing" generating facility may trip during a frequency or voltage excursion due to upsets caused by events on the auxiliary system (such as the cited contactor drop out). Requirement R4 is included in the standard to allow planning entities to obtain an estimate of such performance from the Generator Owner so the facilities can be appropriately modeled. The SDT does not believe it is realistic to require all "existing" generating facilities to be rebuilt to ensure performance to the level of Requirement R5.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Los Angeles Department of Water and Power		LADWP supports the following comment below:"The curve depicting the "no trip zone" for WECC in Attachment A is not consistent with the overfrequency and underfrequency requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan (Plan). A step is missing in the curve for the underfrequency

Organization	Yes or No	Question 8 Comment
		requirements. The table representing the points on the "no trip zone" curve for WECC is also missing the same step as the plot. Additionally the presentation of the information in the table is confusing. As presented, the table specifies a time range of staying connected for selected specific frequencies. The table should specify a specific time for staying connected for frequency ranges. For example, as currently depicted in the table, a generator would need to stay connected up to 0.75 seconds (or between 0 and 0.75 seconds) at 57.0 Hz. The WECC Plan allows for instantaneous trips at 57.0 Hz. Further, the WECC Plan requires the generator to stay connected for 45 cycles (0.75 seconds) for frequencies greater than 57.0 Hz. but less than or equal to 57.3 Hz. This is not accurately reflected in the Table. The plot in Attachment A and the associated tables must be corrected to accurately reflect the requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan."
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected.		
Lakeland Electric	Negative	LAK is a member of FMPA, please refer to their comments.
Manitoba Hydro		Manitoba Hydro is voting negative for the following reasons:1 - R1 - the facility interconnection document required through FAC-001 should supersede Attachment 1 in order to best address local area issues. R1 should be revised to specify this. **The SDT was charged with creating continent-wide requirements for frequency and voltage excursions and believes that consistency will not occur if various Transmission Service Providers apply various "no trip zones." Requirement R1, therefore, should not be dictated by FAC-001.** 2 - NERC IVGTF Task Force Document - the SDT should consider the recommendations from the NERC IVGTF Task Force 1.3 document. Specifically, the recommendations regarding clarifying the potential coordination issues between TPL-001 and PRC-024, clearly defining performance requirements for unbalanced and

Organization	Yes or No	Question 8 Comment
		balanced faults, and defining the performance required during and after disturbances and making clear and unambiguous statements as to what remaining “connected” entails (i.e. how much real power is expected to be delivered post disturbance and how long until the normal pre-disturbance power can delivered) should be considered. **The SDT reviewed the NERC IVGTF Task Force 1.3 document. Changes in the wording to Clarifications#2 and #5 to Attachment 2 have been made that address the concern with unbalanced and balanced faults. At this point, the SDT does not have a technical basis for defining requirements for performance during and after disturbances. Section 3.5.3 of the IVGTF document states, “A detailed power recovery characteristic for variable generators is not necessary to be specified in a standard.”** 3 - Low Voltage Ride Through clarification - more information is required on the low voltage ride through curve. The GO should be required to provide unit outputs and ramp rates for the different voltage transitions and levels on the ride-through curve. **The SDT believes it the uncertainties involved in trying to determine generator outputs and ramp rates would not improve grid reliability.** 4 - Data Retention - The data retention requirements are too uncertain for two reasons. First, the requirement to “provide other evidence” if the evidence retention period specified is shorter than the time since the last audit introduces uncertainty because a responsible entity has no means of knowing if or when an audit may occur of the relevant standard. Secondly, it is unclear what ‘other evidence’, besides the specified evidence in the Measures, an entity may be asked to provide to demonstrate it was compliant for the full time period since their last audit. **The SDT agrees and has modified the wording in the Data Retention section of the standard to match that being used in other recently-approved NERC standards.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Nebraska Public Power District	Negative	Nebraska Public Power District (NPPD) supports the comments submitted through

Organization	Yes or No	Question 8 Comment
		the Midwest Reliability Organization (MRO) NERC Standards Review Forum (NSRF).
Dynegy		No
Omaha Public Power District	Negative	OPPD has singed on to MRO's NSRF comments
Puget Sound Energy		Our existing units capabilities are outside those required in the frequency attachment.
Response: Thank you for your comments. The SDT is pleased that your generating units will meet Requirement R1.		
Minnkota Power Coop. Inc.	Negative	Please see comments submitted by the MRO NSRF.
Lakeland Electric	Negative	Please see FMPA comments
MidAmerican Energy Co.	Negative	Please see MidAmerican and MRO NSRF Comments.
MidAmerican Energy Co.	Negative	Please see MidAmerican and NSRF comments.
MidAmerican Energy Co.	Negative	Please see MidAmerican and NSRF comments.
MidAmerican Energy Co.	Negative	Please see MidAmerican and NSRF comments.
Madison Gas and Electric Co.	Negative	Please see MRO NSRF comments
Great River Energy	Negative	Please see MRO NSRF comments.
Fort Pierce Utilities Authority	Negative	Please see separately submitted formal comments by Florida Municipal Power Agency
Muscatine Power & Water	Negative	Please see the comments submitted by MRO NSRF

Organization	Yes or No	Question 8 Comment
North Carolina Electric Membership Corp.	Negative	Please see the formal comments submitted by ACES Power Marketing.
Sunflower Electric Power Corporation	Negative	Please see the formal comments submitted by ACES Power Marketing.
Beaches Energy Services	Negative	R2 - point of interconnection is confusing. We recommend putting the footnote into body of requirements and replace "point of interconnection" with "high side of GSU or collector bus" **The SDT believes Footnote 3 clearly explains the meaning of "point of Interconnection," as used in this standard.** R3.1, the second bullet, should be clarified to explain that the equipment replaced is plural, meaning all equipment causing a limitation would need to be replaced, e.g., if one piece of equipment was replaced, but another stil causes a limitation, the "grandfathering" of existing equipment lmimtations should still be in place. **The SDT does not intend the "equipment" to necessarily be plural. For that reason, the SDT said, "The equipment…" instead of "All equipment…" If there are multiple pieces of equipment that are causing limitations, only those that are replaced as a result of an upgrade would have to be designed to meet the full range of the no trip zones in Attachments 1 and 2.** R1 and R2 are inconsistent with R5, bullet 5.2. R1 and R2 provide no exceptions for a new plant/wind farm/solar farm, R5 bullet 5.2 does. **There are no exceptions for "new" facilities in Requirements R1 and R2 because "new" facilities are expected to meet the performance requirements of Requirement R5. Part 5.2 (now 5.1) does allow up to 10% of a facility consisting of multiple small units to trip which is analogous to a power runback of a single large generator.** R6 is ambiguous as to whether or not any time any protection settings are changed, whether or not they violate the curves, the entity has to notify and provide the settings. It should be limited to only generators that violate the curves. Or is it that all trip settings of all generators are intended to be modeled? We would think that we

Organization	Yes or No	Question 8 Comment
		do not need to model the generator trip settings for those that meet the curves because the UFLS program is supposed to prevent us from reaching those curves. Hence, we should only need to model the trip settings of those generators that do not meet the curves. **The SDT assumes that the requestor would only ask for settings for the protection functions that are modeled for stability or UFLS performance. Typically, most generator protection functions are not included in these models. However, in order to predict the generators' behavior accurately, the entity creating the model must know the settings for all of the modeled protection functions, not just those that do not meet Requirements R1 or R2. Following such a request, only changes to the settings that have been requested would need to be reported. The SDT has added the words "unless otherwise directed" so that the requestor can indicate that future changes do not have to be reported (as may be the case for a one-time study that will not be repeated).**
Response: Thank you for your comments. Please see the responses to specific comments above.		
American Electric Power		R2 is very "wordy", essentially a single run-on sentence which references yet additional material in its two footnotes, making it difficult to follow. This could be made more clear with the usage of bulleted items.R2.1.1 through R2.1.4 could be and perhaps should be R2.2 through R2.5. **The SDT agrees that Requirement R2 could be improved and has shortened the initial sentence by moving the reference to Requirement R3 to Part 2.6 and has restructured the other Parts as suggested.** R3: We recommend adding "known" to R3 such as "...shall document each known equipment limitation..." to make clear that a GO is not responsible for a cause they are not aware of. **The SDT has added the word "known" as for clarity as suggested, although the SDT believes the Generator Owner would not set its protection inside the no trip zone because of "unknown" limitations.** R3: The second point under R3 causes the limitation to expire with rating increases. Is a 10percent or more rating increase a realistic scenario and common enough to justify attention?10 percent seems arbitrary and this provision could pose a

Organization	Yes or No	Question 8 Comment
		hindrance to rating increasesthat may supply other reliability benefits. It may be advisable to remove this point. **The SDT agrees that ten percent is an arbitrary number. The SDT feels that if a Generator Owner is making enough of an investment in a facility to achieve a ten percent increase in rating, then any limitations caused by the equipment being upgraded should be eliminated. If AEP can provide a technical justification for a different number the SDT would be very interested.** R4.1 should include the Planning Coordinator in addition to the TP because the PC is responsible for UFLS coordination and assessment in PRC-006-1. **Requirement R4 has been extensively revised. It should be clearer now that the Planning Coordinator is one of the entities allowed to request the performance estimate from the Generator Owner.** R5.2 should be removed because of its obvious partiality toward wind farms. **Part 5.2 (now 5.1) gives an allowance for loss of up to 10% of units at a site with many small units which is analogous to a runback in power on a single larger unit.** R5.6 needs to include coordination with the Planning Coordinator because of the PC's responsibilities with respect to automatic UFLS. This should also perhaps include coordination with the Transmission Planner for exceptions on voltage excursion ride-through. **Both the Planning Coordinator and Transmission Planner are allowed to request a performance estimate from a Generator Owner in Requirement R4. The SDT believes this gives these entities access to the pertinent information.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Florida Municipal Power Agency		R3.1, the second bullet, should be clarified to explain that the equipment replaced is plural, meaning all equipment causing a limitation would need to be replaced, e.g., if one piece of equipment was replaced, but another stil causes a limitation, the "grandfathering" of existing equipment lmimtations should still be in place. **The SDT does not intend the "equipment" to necessarily be plural. For that reason, the SDT**

Organization	Yes or No	Question 8 Comment
		said, "The equipment…" instead of "All equipment…" If there are multiple pieces of equipment that are causing limitations, only those that are replaced as a result of an upgrade would have to be specified to meet the full range of the no trip zones in Attachments 1 and 2. R1 and R2 are inconsistent with R5, bullet 5.2. R1 and R2 provide no exceptions for a new plant/wind farm/solar farm, R5 bullet 5.2 does. **There are no exceptions for "new" facilities in Requirements R1 and R2 because "new" facilities are expected to meet the performance requirements of Requirement R5. Part 5.2 (now 5.1) does allow up to 10% of a facility consisting of multiple small units to trip which is analogous to a power runback of a single large generator.** R6 is ambiguous as to whether or not any time any protection settings are changed, whether or not they violate the curves, the entity has to notify and provide the settings. It should be limited to only generators that violate the curves. Or is it that all trip settings of all generators are intended to be modeled? We would think that we do not need to model the generator trip settings for those that meet the curves because the UFLS program is supposed to prevent us from reaching those curves. Hence, we should only need to model the trip settings of those generators that do not meet the curves. **The SDT assumes that the requestor would only ask for settings for the protection functions that are modeled for stability or UFLS performance. Typically, most generator protection functions are not included in these models. However, in order to predict the generators' behavior accurately, the entity creating the model must know the settings for all of the modeled protection functions, not just those that do not meet Requirements R1 or R2. Following such a request only changes to the settings that have been requested would need to be reported. The SDT has added the words, "unless otherwise directed" so that the requestor can indicate that future changes do not have to be reported (as may be the case for a one-time study that will not be repeated).**

Response: Thank you for your comments. Please see the responses to your specific comments above.

Organization	Yes or No	Question 8 Comment
City of Vero Beach		R3.1, the second bullet, should be clarified to explain that the equipment replaced is plural, meaning all equipment causing a limitation would need to be replaced, e.g., if one piece of equipment was replaced, but another stil causes a limitation, the "grandfathering" of existing equipment lmimtations should still be in place. **The SDT does not intend the "equipment" to necessarily be plural. For that reason, the SDT said, "The equipment…" instead of "All equipment…" If there are multiple pieces of equipment that are causing limitations, only those that are replaced as a result of an upgrade would have to be specified to meet the full range of the no trip zones in Attachments 1 and 2.** R1 and R2 are inconsistent with R5, bullet 5.2. R1 and R2 provide no exceptions for a new plant/wind farm/solar farm, R5 bullet 5.2 does. **There are no exceptions for "new" facilities in Requirements R1 and R2 because "new" facilities are expected to meet the performance requirements of Requirement R5. Part 5.2 (now 5.1) does allow up to 10% of a facility consisting of multiple small units to trip which is analogous to a power runback of a single large generator.** R6 is ambiguous as to whether or not any time any protection settings are changed, whether or not they violate the curves, the entity has to notify and provide the settings. It should be limited to only generators that violate the curves. Or is it that all trip settings of all generators are intended to be modeled? We would think that we do not need to model the generator trip settings for those that meet the curves because the UFLS program is supposed to prevent us from reaching those curves. Hence, we should only need to model the trip settings of those generators that do not meet the curves. **The SDT assumes that the requestor would only ask for settings for the protection functions that are modeled for stability or UFLS performance. Typically, most generator protection functions are not included in these models. However, in order to predict the generators' behavior accurately, the entity creating the model must know the settings for all of the modeled protection functions, not just those that do not meet Requirements R1 or R2. Following such a request only changes to the settings that have been requested**

Organization	Yes or No	Question 8 Comment
		would need to be reported. The SDT has added the words, "unless otherwise directed" so that the requestor can indicate that future changes do not have to be reported (as may be the case for a one-time study that will not be repeated).
Response: Thank you for your comments. Please see the responses to your specific comments above.		
City of Green Cove Springs	Negative	R3.1, the second bullet, should be clarified to explain that the equipment replaced is plural, meaning all equipment causing a limitation would need to be replaced, e.g., if one piece of equipment was replaced, but another stil causes a limitation, the "grandfathering" of existing equipment lmimtations should still be in place. **The SDT does not intend the "equipment" to necessarily be plural. For that reason, the SDT said, "The equipment…" instead of "All equipment…" If there are multiple pieces of equipment that are causing limitations, only those that are replaced as a result of an upgrade would have to be specified to meet the full range of the no trip zones in Attachments 1 and 2.** R1 and R2 are inconsistent with R5, bullet 5.2. R1 and R2 provide no exceptions for a new plant/wind farm/solar farm, R5 bullet 5.2 does. **There are no exceptions for "new" facilities in Requirements R1 and R2 because "new" facilities are expected to meet the performance requirements of Requirement R5. Part 5.2 (now 5.1) does allow up to 10% of a facility consisting of multiple small units to trip which is analogous to a power runback of a single large generator.** R6 is ambiguous as to whether or not any time any protection settings are changed, whether or not they violate the curves, the entity has to notify and provide the settings. It should be limited to only generators that violate the curves. Or is it that all trip settings of all generators are intended to be modeled? We would think that we do not need to model the generator trip settings for those that meet the curves because the UFLS program is supposed to prevent us from reaching those curves. Hence, we should only need to model the trip settings of those generators that do not meet the curves. **The SDT assumes that the requestor would only ask for settings for the protection functions that are modeled for stability or UFLS**

Organization	Yes or No	Question 8 Comment
		performance. Typically, most generator protection functions are not included in these models. However, in order to predict the generators' behavior accurately, the entity creating the model must know the settings for all of the modeled protection functions, not just those that do not meet Requirements R1 or R2. Following such a request only changes to the settings that have been requested would need to be reported. The SDT has added the words, "unless otherwise directed" so that the requestor can indicate that future changes do not have to be reported (as may be the case for a one-time study that will not be repeated).
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Atlantic City Electric Company	Negative	Refer to comments submitted by Pepco Holdings Inc and Affiliates.
ReliabilityFirst		ReliabilityFirst votes in the affirmative for the the PRC-024-1 standard because the standard further enhances reliability by ensuring that generating units remain connected during frequency excursions. Even though ReliabilityFirst votes in the affirmative, we offer the following comments for consideration:1. Requirement R5 and associated Subpart 5.1a. ReliabilityFirst believes there is a potential conflict and seeks clarification on the choice of words between Requirement R5 and associated Subparts 5.1 and 5.1.1. Requirement R5 begins by stating "Each Generator Owner shall design, build, and maintain its new unit or new generating plant..." which lends itself more to the "planning" type stages while Subpart 5.1 states "When the generating unit or generating plant is operating at or above the minimum sustainable generation threshold" which lends itself to actual "operation" of the unit. ReliabilityFirst questions how the conditions in Subpart 5.1 and 5.1.1 can be utilized if the actual "operation" of the unit has yet to be observed since Requirement R5 is dealing with the design stages of a new unit? **The SDT believes the design, construction, and maintenance of a generating facility are the key elements in assuring that the facility is able to remain connected to the grid during the excursions defined in the standard. There is really nothing that can be done operationally to prevent a generator from tripping if it has not been designed, built,**

Organization	Yes or No	Question 8 Comment
		and maintained correctly. There are, however, certain operating regimes (e.g. start-up and shut-down) when generating units are much less stable and less capable of remaining connected during an excursion. The SDT believes there is not a large reliability risk to allow a generator to trip if it is in this condition when an excursion occurs given the short term nature of operation in these regimes. 2. Requirement R6 a. ReliabilityFirst request further clarity regarding whether the parenthetical, “(that monitors or models the associated unit),” is associated with all the requesting entities listed in Requirement R6 (RC, PC, TOP, and TP) or just the TP. **The parenthetical refers to all four of the named entities.** 3. VSL Requirement R5 a. Requirement R5 states “Each Generator Owner shall design, build, and maintain its new unit or new generating plant so that it will not trip due to a frequency excursion or voltage excursion.” The VSL states “The Generator Owner’s generator tripped due to a Frequency Excursion within the no-trip parameters set forth in attachment 1”. Based on the FERC Guideline #3 "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement," the language in the requirement is not consistent with the associated VSL. It is not a violation of Requirement R5 if the generator tripped offline within the no-trip parameters, rather it is a violation if the GO failed to design, build, and maintain its new unit or new generating plant so that it will not trip due to a frequency excursion or voltage excursion. ReliabilityFirst recommends the following language for the “High” VSL, “The Generator Owner failed to design, build, and maintain its new unit or new generating plant so that it will not trip during a frequency excursion within the no-trip parameters set forth in Attachment 1. OR The Generator Owner failed to design, build, and maintain its new unit or new generating plant so that it will not trip during a voltage excursion within the no-trip parameters set forth in Attachment 1. **The VSL relates to Measure M5. The Measure relates to how the entity demonstrates that they have designed, built, and maintained the generating unit so that it does not trip during an excursion. Requirement R5 is written as a performance requirement. The words “design, build, and maintain” give the Generator Owners guidance as to how to achieve the performance**

Organization	Yes or No	Question 8 Comment
		objective. b. ReliabilityFirst also noted there is no mention of the Subparts 1.1 through 1.7 in the VSL (ReliabilityFirst understands that these are "Conditions and Exceptions" but they should somehow be incorporated into the VSLs. **VSL's only apply when a violation of the requirement occurs. Parts 5.1 – 5.7 (now 5.1 – 5.6) are part of the requirement.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Gulf Power Company	Negative	See comments submitted via the electronic comments form by Antonio Grayson.
Dairyland Power Coop.	Negative	See MRO NSRF comments. In addition: The VSL must match the requirements of the standard. VSL R4 indicates a different calendar schedule than that of requirement R4. Requirement R4 indicates 60 calendar days after receipt of written request to provide information. VSL R4 indicates levels of severity less than 60 calendar days. **The SDT agrees and has revised the wording in the Requirement R4 VSL to address the issue.** Requirement R6 states "Each Generator Owner shall provide its generator protection trip settings to the...". Trip settings is open to interpretation. Please clarify what is meant by the term "trip settings", is meant to provide all trip settings or just specific trip settings. **The requesting entity will specify which protective functions he is modeling for which the trip settings (as opposed to settings that may be set to alarm only) must be reported. In this standard "trip" means disconnecting the generator from the transmission system.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
U.S. Army Corps of Engineers	Negative	See MRO/NSRF comments
Occidental Chemical	Negative	See submitted comments on behalf of Ingleside Cogeneration LP

Organization	Yes or No	Question 8 Comment
GenOn Energy		Thank you to the SDT for you efforts to produce a quality standards.R3 should be worded in a similar manner to R4. "The Generator Owner shall document the estimated equipment limitations..." The problem with a requirement like R3, is that documenting "each" equipment limitation on older facilities will contain uncertainties and unknowns. **The SDT has added the word "known" to qualify the equipment limitations for clarity, although the SDT does not see why a Generator Owner would set the protection system to operate inside the no trip zones due to unknown limitations.** The implementation schedule for the requirements will be more efficient if the schedule is aligned with the PRC-019 schedule rather than having the two similar efforts on different tracks. **The SDT agrees and has changed the implementation period, relative to Requirements R1, R2, R3, R4 and R6, of PRC-024-1 to match that of PRC-019.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Alberta Electric System Operator		The AESO does not support the changes made to the Curve Details, in the Voltage Ride-Through Curve Clarifications section of the standard, in particular the use of the term "base voltage" . In many parts of the Alberta transmission system the maximum normal operating voltages are significantly higher than 1.05pu of than the "base voltage" used in studies. The system has been studied, planned and designed around these higher voltages. For example; in a study the base (nominal) voltage is chosen to be one per unit (1.0 pu) equals 240 kV but in the study area typical operating voltages are 256 kV (1.07 pu) and can be as high as 1.10 pu.
Response: Thank you for your comments. The SDT has modified Clarification #1 to Attachment 2 by removing the words "base voltage" and "in the system models" and has replaced them with "nominal operating voltage" (specified by the Transmission Planner). The SDT believes this will address the different operating criteria used in different regions.		
Western Electricity		The Attachment depicting the No Trip Zone for frequency excursions for the WECC

Organization	Yes or No	Question 8 Comment
Coordinating Council		Interconnection is incorrect. It is missing one of the steps from the materials provided to the drafting team in July. The table is also missing a step. This must be corrected. In my opinion, the table identifying the High and Low Frequency Duration information is hard to interpret. As depicted, the table appears to be giving a range of time that a generator must stay interconnected at a specific frequency. I am not familiar with the requirements in other regions, but in WECC, we have specified a specific time that a generator must stay interconnected for a frequency range. In looking at the WECC table included int he draft standard I would not be able to discern how long a generator had to stay interconnected if the frequency were at 59.0 Hz. Similarly, I have the same problem with the information in the tables for the other interconnections. After discussions with drafting team representatives, an suggested revision for the format of the tables has been proveded to the drafting team for consideration.Even with the inclusion of the (not including the lines) statement on the No Trip Zone plot, it is still difficult to determine minute specifications from the plot. Depending on the quality of the diagram and the thickness of the line, there will still be the potential for debate. I believe a solution is to indicate the plot is for illusrative purposes only, and the specifics are provided in the tables. With the suggested format changes provided to the drafting team, there should be no room for speculation.Whether the Off-Nominal Frequency Capability Curve is used for illustrative purposes as suggested above, or for specifying details, it is difficult to view as presented. One option would be to provide three individual plots, one for each interconnection, and include them all as Attachment 2. This way you could still refer to Attachment A in Requirement R2, and perhaps add language such as "appropriate plot in Attachment 2" to the requirement.
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected.		
California Independent		The California Independent System Operator Corporation has adopted tariff requirements for generator frequency and voltage ride through capabilities that

Organization	Yes or No	Question 8 Comment
System Operator		apply to synchronous generators as well as requirements for generator frequency and voltage ride through capabilities that apply to asynchronous generators. As written, the requirements of draft PRC-024-1 apply to both synchronous and asynchronous generators. The ISO requests that the Generator Verification Standard Drafting Team confirm this reading of draft PRC-024-1, and suggests making this clarification in PRC-024-1 as well.
Response: Thank you for your comments. Under "Generator Owner" the Registry Criteria makes no distinction between synchronous and asynchronous generators. The SDT intends for both synchronous and asynchronous generators to be included as implied in the Registry Criteria and therefore made no specific distinction.		
Bonneville Power Administration		The curve depicting the "no trip zone" for WECC in Attachment A is not consistent with the overfrequency and underfrequency requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan (Plan). A step is missing in the curve for the underfrequency requirements. The table representing the points on the "no trip zone" curve for WECC is also missing the same step as the plot. Additionally the presentation of the information in the table is confusing. As presented, the table specifies a time range of staying connected for selected specific frequencies. The table should specify a specific time for staying connected for frequency ranges. For example, as currently depicted in the table, a generator would need to stay connected up to 0.75 seconds (or between 0 and 0.75 seconds) at 57.0 Hz. The WECC Plan allows for instantaneous trips at 57.0 Hz. Further, the WECC Plan requires the generator to stay connected for 45 cycles (0.75 seconds) for frequencies greater than 57.0 Hz. but less than or equal to 57.3 Hz. This is not accurately reflected in the Table. The plot in Attachment A and the associated tables must be corrected to accurately reflect the requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan.
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also		

Organization	Yes or No	Question 8 Comment
been corrected.		
Consolidated Edison Co. of NY, Inc.		The definition of the terms Frequency Excursion and Voltage Excursion were deleted.All references to these terms should now be lower case. Measures M4 and M5 continue to carry the prior wording and need to be revised to use lower case terms.
Response: Thank you for your comments. The capitalization has been removed as suggested.		
Northeast Power Coordinating Council		The definitions of the terms Frequency Excursion and Voltage Excursion were deleted. All references to these terms should be lower case. Measures M4 and M5 continue to carry the prior wording and need to be revised to use the lower case terms. **The capitalization has been removed as suggested.** Regarding requirement R2, the time duration is acceptable. However, the band is shown as 0.95 per unit to 1.05 per unit at the point of interconnection, and there are areas of the power system that have not been designed to maintain steady state operation within this band. The band needs to be expanded to 0.90 per unit to 1.05 per unit. Failure to make this change means that it would be acceptable for generators to trip during steady state operation of the system on "low" voltage. Unanticipated and unncecessary tripping of generators under steady state conditions could lead to significant reliability concerns on the system. **The voltage band applies to the point of interconnection of an operating generator. Presumably, the generator would be holding that voltage within the scheduled voltage band provided by the Transmission Operator per VAR-001. Other portions of a transmission system may be at significantly different voltages, but that would not give the generator an excuse to trip. If it is necessary to have an expanded band of normal operating voltage for a particular region, it can be mandated through a regional standard without imposing the same requirements on the entire continent.** The PTs connected to the high voltage terminals of the GSU may not be used as a

Organization	Yes or No	Question 8 Comment
		source for generator protective relaying. Generator protective relays may be connected to the generator output terminals for their source of potential. The wording of R2 should incorporate generator terminals in addition to point of interconnection. **The SDT agrees that generator protection normally senses the voltage at the generator terminals. Because there are many configurations of the connections of the generators to the transmission systems, it is not practical to develop a single voltage curve defined at the generator terminals that equates to the voltage caused by an event on the transmission system. Each Generator Owner will have to determine how the transmission system event affects his specific generating units. This approach is consistent with FERC Order 661A and other international grid standards that are in effect.** Regarding R3, in the event that a generator has a piece of equipment which prevents it from meeting the requirements of R1 and R2, such as a motor contactor which drops out on voltages in the “No Trip Zone”, there is no requirement to correct the issue. The generator must only document the limitation. This completely undermines the intent of this standard. It is counterproductive to set undervoltage relays to meet the curve if other equipment is still going to trip the plant for those same conditions. This standard appears to simply document system concerns rather than identify and correct them. **Requirements R1 and R2 apply to generator protection, not to the auxiliary systems. An “existing” generating facility may, indeed, trip during a frequency or voltage excursion due to upsets caused by events on the auxiliary system (such as the cited contactor drop out). Requirement R4 is included in the standard to allow planning entities to obtain an estimate of such performance from the Generator Owner so the facilities can be appropriately modeled. The SDT does not believe it is realistic to require all “existing” generating facilities to be rebuilt to ensure performance to the level of Requirement R5.** Under Requirement R5, 5.5 (exception) is unnecessary. It does not have to be stated that a generating unit or generating plant may trip if clearing a system fault necessitates disconnecting the generating unit or generating plant. **The SDT agrees that it is self-evident from a technical perspective, but is included for completeness**

Organization	Yes or No	Question 8 Comment
		for compliance auditing purposes.
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Duke Energy		The frequency and voltage ride-through curves are at the point of interconnection. Conditions inside a generating plant will depend upon how the generator responds to the transient. Models will have to be built and validated against plant-specific auxiliary equipment performance expectations.
Response: Thank you for your comments. The SDT assumes this comment is in reference to Requirement R4. The SDT does not require Generator Owners to do extensive dynamic simulations to determine performance. The SDT believes the Generator Owner could identify the most likely piece of equipment to fail to ride through (whether from contactor drop out or other mechanism) and estimate the time between that event and a generator trip due to the resulting process upset.		
MRO NSRF		The MRO NSRF believes that an entity having to attest to the fact that a generating unit or plant did not trip offers no foreseeable benefit to reliability. As currently stated, Measure M5 could be interpreted to mean that an entity would need to provide a letter of attestation each day or month a generating unit or plant were to function as intended. The MRO NSRF recommends the drafting team either remove this statement or else rephrase the Measure to avoid the expectation that entities verify normal operation. **The SDT agrees with your comment and has removed the wording that requires the attestation as evidence.** Additionally, as frequency excursion and voltage excursion are not NERC-defined terms nor terms to be defined as part of this project, recommend the terms be placed in lowercase letters to maintain consistency with the Requirement. M5. Each Generator Owner shall have evidence, such as dated unit output records, trip investigation reports or disturbance monitoring records, showing that each unit trip did not result from a FfrequencyEexcursion or VvoltageEexcursion as specified in Requirement R5, or evidence that a listed exception applied, or provide an attestation that the generating unit or generating plant did not trip. **The SDT agrees**

Organization	Yes or No	Question 8 Comment
		with your comment. The capitalization has been removed as suggested. Please give consideration to the following suggestions:1. In Requirements R2 - the text refers to “non-protection system equipment” but this terminology is not defined. Provide some definition/description and perhaps a list of this type of equipment in a footnote to improve clarity. **The SDT has removed the term “non-protection system” from the wording in Requirement R2. In Requirement R3 the parenthetical has been revised so that it reads “(excluding limitations that are caused by generator frequency and voltage protective relays).”** 2. In Requirements, R3 - add the requirement that the GO provides the expected duration of the limitation, if it is known. . **In general, the SDT believes these limitations are permanent due to equipment design or regulatory considerations. The Reliability Coordinator, Planning Coordinator, Transmission Operator, or Transmission Planner may certainly inquire if they believe the Generator Owner is describing a temporary limitation.** 3. Request MOD-026 and MOD-027 be verified for redundancy with PRC-024.In the applicability section the only reference is to Generator Owner. It is recommended the applicability section include a statement that the affected units are only those that are a part of the Bulk Electric System. **The SDT does not believe MOD-026 or MOD-027 are redundant with PRC-024. The MOD standards require model validations where PRC-024 is a generator protective relaying setting and generator performance standard. The SDT feels that the applicable generators owned by a “Generator Owner” is clearly stated in the Registry Criteria and that no further clarification is required.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Kansas City Power & Light Co.	Negative	The proposed change to requirement 1.1 will allow for generator trips in operating conditions involving automatic load shedding action and increase the risk of taking the interconnection into a black out condition.

Organization	Yes or No	Question 8 Comment
Response: Thank you for your comments. The allowance to trip for a specific rate of change of frequency that was specified in Requirement R1, Part 1.1 was provided so that any relaying added to protect from "Aurora" events would be allowed to trip the unit. The SDT investigated several major grid separation events and found that the rate of change of frequency during these events did not approach the 2.5 Hz/sec specified in the standard. However, it appears to the SDT that including the rate of change of frequency criterion in Requirement R1 is confusing industry and that "Aurora" protection is among the functions allowed to trip a generator due to impending or actual loss of synchronism or stability (Part 1.2 – now 1.1) and removed the rate of change of frequency criterion.		
Public Utility District No. 1 of Lewis County	Negative	The standard does not list a minimum size generator that this standard applies to. Our utility has one plant with two small generators. The plant is near a project 10 times our size. We do not have the monitoring equipment to run this frequency or voltage testing. Therefore we must hire the work done. We get little or no benefit from the testing and money spent. Suggest the standard state a minimum generator size of 100 MVA that verification is required.
Response: Thank you for your comments. The SDT feels that the applicable generators owned by a "Generator Owner" is clearly stated in the Registry Criteria and that no further clarification is required.		
Southern California Edison Company		The standard should allow for wider regional variances - for example, WECC allows lower frequency and voltage excursions.
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 2007 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected.		
Northern Indiana Public Service Co.	Negative	There is a concern about inconsistencies between the Standards and Appendices
Response: Thank you for your comments. The SDT cannot address your concern without knowing the specifics of the inconsistencies to which you refer. Standard PRC-024 does not have any Appendices.		

Organization	Yes or No	Question 8 Comment
Indiana Municipal Power Agency		This standard should concentrate on being a relay standard because it is not practical to include equipment limitations (excluding generator frequency and voltage protective relay equipment) that might trip the generating unit or generating plant offline. Just to figure out what the equipment limitations are at a generating plant an entity would have to perform a complete analysis and stability study on the generating plant including all auxiliary systems. If an entity cannot do this within it's organization, it will have to hire a contractor and/or outside consultant to inventory, test, and model the unit/plant. This type of analysis will be expensive and will come without any guarantees from the contractor that all the equipment limitations have been noted or discovered. In addition to the initial testing that a unit/plant will require to meet this standard, an entity will have to perform some type of routine testing and maintenance program in this area to ensure equipment characteristics have not changed enough to become a plant limitation (heat and age changes equipment characteristics). Based on this standard, entities will have to have equipment tested and built to certain specifications that will allow it to ride through a voltage and/or frequency excursion which will increase equipment and maintenance costs and could potentially limit equipment suppliers. One has to wonder if all of this cost will guarantee an increase in BES reliability that makes it worth paying for the work and equipment that will be needed for compliance (with the chance that the plant will still trip offline). In how many past instances has what this standard is trying to protect against been a proven issue? **The SDT agrees that studies will have to be done to design generating units (especially their auxiliary systems) to be able to ride through the types of transmission system voltage excursions defined in this standard. Since similar requirements are already in effect in parts of Europe and Asia, the SDT believes it is technically feasible.** There term "power conversion control equipmen"t is not defined and will allow entities to apply this term to different equipment which may or may not be correct. The SDT should take the time to define it now and not allow a CAN to define it. **There are a lot of terms that are not defined in the standard. The SDT prefers to refrain from adding definitions unless it is clear there is widespread confusion. You were**

Organization	Yes or No	Question 8 Comment
		the only entity to comment on this term. In this standard it refers to the electronics associated with asynchronous generator technologies. Measure five (M5) is currently written so that it appears that an entity will have to purchase a Digital Fault Recorder(s) for the unit/plant in order to produce the evidence needed to show a unit tripped offline (i.e. frequency rate of change greater than 2.5 Hz/sec) outside of the "no trip" zone. IMPA does not agree with this philosophy since the cost to purchase and install DFR's can be costly, especially to smaller entities. **Measure M5 does not require the purchase of any particular type of equipment. There are protective relays and voltage regulators with oscillographic recording capability. The Transmission Owner may already have a fault recorder in the substation. This requirement only applies to new units following a six-year implementation period to give time to budget for and design equipment to meet the requirement. In the event that it is determined that a fault recorder is the best option and does not exist in the substation the SDT believes the cost of adding a DFR as a percentage of the cost of building a new unit to be very small.** Why is 5.2 allowed for new units but not existing units**? Existing units are only required to set their protection systems such that they won't operate during an excursion as defined in the standard, but still may trip due to process upsets caused by the excursion. Requirement R5, however, does require new units to be designed to remain connected despite any process upsets. A generating unit may experience a power runback (which is allowed) and Part 5.2 (now 5.1) gives a facility with multiple small units an analogous allowance.** In 5.6, what makes the Mitigation Plan acceptable? Who needs to approve or make the Mitigation Plan acceptable. Where is the Mitigation Plan defined? IMPA believes the word "acceptable" should be removed. **The Reliability Coordinator has the discretion to determine if the plan to address the limitation that is submitted by a Generator Owner is acceptable. The SDT believes Part 5.6 (now 5.5) is worded correctly.**

Organization	Yes or No	Question 8 Comment
Response: Thank you for your comments. Please see the responses to your specific comments above.		
PSEG		We have these additional comments:a. In Part 4.1 of R4, the first sentence has this proposed change, indicated by capilatization: "An estimate of the time duration the existing generating unit or generating plant will remain connected (considering performance of the auxiliary systems as well as the generator) as a result of a frequency excursion or a voltage excursion defined by the voltage or frequency profile at the point of interconnection [deleted "described by"] THAT WAS DEVELOPED FROM A dynamic simulation provided by the Transmission Planner. **The SDT agrees and has revised the wording in Requirement R4.** b. M5 is confusing. M5 states "Each Generator Owner shall have evidence, such as dated unit output records, trip investigation reports or disturbance monitoring records, showing that each unit trip did not result from a Frequency Excursion or Voltage Excursion as specified in Requirement R5, or evidence that a listed exception applied, or provide an attestation that the generating unit or generating plant did not trip."i. Frequency Excursion and Voltage Excursion are capitalized terms - the previous version's defined terms were supposed to be removed. **The SDT agrees with your comment. The capitalization has been removed as suggested.** ii. While is appears that an "attestation that the generating unit or generating plant did not trip" is only required for a unit or plant that remained on line during a frequency or voltage excursion, the language should be made clearer. **The SDT agrees with your comment. The language referring to attestations has been removed.** iii. We suggest that the GVSDT consider rewording M5 to clearly state what trips should be reported, whether non-trips that occur during frequency and voltage excursions are to be reported, and what supporting evidence (or attestations) is required for each reported item. A table may be the best way to display this. **Measure M5 does not reference reporting non-trips during an excursion. Thus these events do not need to be reported. By default, the generating unit is compliant if it did not trip, whether there was an excursion or not.**

Organization	Yes or No	Question 8 Comment
		Finally, M5 should be developed to produce the VSL metric for R5. **The SDT believes that the VSL does cover both the Requirement its associated Measure.** c. The previously defined terms "Frequency Excursion" and "Voltage Excursion" were to be removed from this draft; however they are used in R4 and in the VSL table. The GVSDT should search the standard for all such usage and correct it. **The capitalization has been removed as suggested.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Gainesville Regional Utilities	Negative	We support FMPA's position on this matter.
Southwest Power Pool Standards Development Team		We would suggest revision of M5 to read. Also since the two terms Frequency Excursion and Voltage Excursion are no longer to be defined by this project we would ask that you use the lower case for these terms in the standard. M5. Each Generator Owner shall have evidence, such as dated unit output records, trip investigation reports or disturbance monitoring records, showing that each unit trip did not result from a frequency excursion or voltage excursion as specified in Requirement R5, or evidence that a listed exception applied.
Response: Thank you for your comments. The capitalization has been removed and reference to the attestation that the unit did not trip has been removed as suggested.		
PacifiCorp		While PacifiCorp has no concerns with this Requirement R5 as applied to new units or generating plant/facilities meeting the point of interconnection frequency excursion performance depicted in Attachment 1 (for the corrected WECC curve), PacifiCorp believes that new units or generating plant/facilities should meet the voltage excursions performance depicted in Attachment 2; however, ultimately it will be up to generator manufacturers to implement necessary facility changes to withstand the voltage excursions.
Response: Thank you for your comments. The SDT appreciates the support for the reliability goals. We would add that it will		

Organization	Yes or No	Question 8 Comment
require changes in auxiliary system configuration and equipment as well as the turbine and generator manufacturers' inputs to achieve the goal.		
Exelon Corp.		The Off Normal Frequency Capability Curve should consist of separate tables for each Interconnect to make it easier to read. **There are already separate data tables for each curve on Attachment 1. The SDT does not believe adding more graphs would add clarification.** Exelon still feels that Footnote 1 belongs in the Applicability section of the standard. Suggest that the Applicability section be revised to state "GO shall set applicable protective relaying so as not to impact R1.1, R1.2, R1.3, R1.5 unless exempted by non-protection system equipment limitations per the exclusion criteria. **The SDT respectfully disagrees. In PRC-024-1, Footnote 1 is intended for clarification purposes only to make it clear that the standard does not force the GO to install voltage or protective relays if they are not already installed on its unit(s).** It should be noted that even if a relay is not set to operate according to the curves in the attachments, a minute deviation will exist in the operation of the relay, and as such, a protection system may operate in what the SDT has deemed the "no trip zone." If a relay operates in that zone, then an entity will technically be out of compliance with this standard even though it set its protection system correctly as per the standard. An allowable tolerance needs to be included in the requirements in order to capture real world conditions. **Relays that are known to drift from their settings should either be calibrated more frequently or set such that a tolerance is built into the relay setting so that the drift will not cross the "no trip zone" boundary.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		

END OF REPORT