NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Generator Verification (MOD-025-2) — Project 2007-09

The Generator Verification drafting team thanks all commenters who submitted comments on the first posting of MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability (Project 2007-09). This standard was posted for a 30-day public comment period from June 15, 2011 through July 15, 2011. The stakeholders were asked to provide feedback on the standards through a special electronic comment form. There were 65 sets of comments, including comments from approximately 182 different people from approximately 95 companies representing nine of the 10 industry segments as shown in the table on the following pages.

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

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President of Standards and Training, Herb Schrayshuen, at 404-446-2563 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

SUMMARY CONSIDERATION:

A number of commenters suggested revisions for clarity that were accepted by the GVSDT. Minor changes were made to the standard to incorporate those suggestions.

- Language was added to recommend that the AVR be in automatic control while conducting reactive capability testing, but that reactive capability testing must be done even if the AVR is not available. The following language was also added to allow flexibility if 90 percent of the generation is not available when testing wind turbines or photovoltaic inverters:

  "If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, the Generator Owner must document the reasons it was unable to meet the threshold and test to the full capability at the time of the test. The Generator Owner shall retest the Facility within six months of being able to reach the 90 percent threshold."

- When polled, most stakeholders agree with combining MOD-024-1 and MOD-025-1 into a single standard. Several commenters suggested that the standard be clarified to indicate that Real and Reactive Power testing may be performed under separate tests. The GVSDT agrees and has separated R1 into two requirements to allow for separate Real and Reactive Power testing. The intent of these requirements remains unchanged. R1 now deals with Real Power testing only while R2 deals with Reactive Power testing. The measure and VSL for R1 were also revised to match the requirements.

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf.

R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1.

1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.

R2. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

2.1. Verify the Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.

2.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.

- A statement was also added to the beginning of Attachment 1 for additional clarity:

  "It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing, however separate testing is allowed for this standard."

- There was an error in the question relating to the Transmission Owner on the previous comment form. The question should have asked if the Transmission Planner was the appropriate entity rather than the Transmission Owner. Most stakeholders suggested that the Transmission Planner is the appropriate entity to receive the data required by MOD-025-1. The GVSDT will confirm this with an additional question on this topic in the next posting.

- With regard to correction factors for verifications, many commenters pointed out there are many factors that affect generator Real Power output, and these factors are different for different types of generating units. The GVSDT has revised the standard to include any parameter that the Generator Owner determines is required to make the ambient correction in Attachment 1:

  3.4. The ambient conditions at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:

  - Ambient air temperature
  - Relative humidity
  - Cooling water temperature

  The standard gives the Transmission Planner the discretion to request ambient condition correction at time of verification.

- There was overwhelming stakeholder support for verifying synchronous condensers as a reactive resource under MOD-025-2. Some stakeholders suggested that consideration be given under this or a different standard for verification of other reactive resources.

  The SDT added the following sentence to Attachment 1 in response to a stakeholder comment for clarity:

  "If a unit is operated in synchronous condenser mode as well as generation mode, the unit should be verified in both modes."

- There was an error in the comment form for the question regarding Synchronous Condenser size. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit. While some commenters suggested values higher than 20 MVA, technical justification was not provided for a value exceeding the generator registration criterion of 20 MVA. The GVSDT will confirm this with an additional question on this topic in the next posting.

Commenters have identified regional variances currently in effect as required by MOD-024 and MOD-025. It is anticipated that these regional standards will be retired once MOD-025-2 is approved. Language provided by Reliability*First* staff has been added to the Implementation plan concerning the Reliability*First* standards:

> "It is the intent of Reliability*First* to perform a review of both the MOD-024-RFC-01 and MOD-025-RFC-01 standards upon NERC Board of Trustees approval of the associated NERC MOD-025-2 standard. The purpose of the review would be to ensure that any duplicative requirements or any requirements which are less restrictive or do not add additional detail will be considered for retirement. The steps outlined in the Reliability*First* Reliability Standards Development Procedure will be followed for any such revisions or retirements."

Index to Questions, Comments, and Responses

Consideration of Comments on First Posting of MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability (Project 2007-09)

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-Serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Brent Ingebrigtson	LG&E and KU Energy	X		X		X	X				
No additional members listed.													
2.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council , LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Brian Evans-Mongeon	Utility Services	NPCC	8
8.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
9.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
10.	Kathleen Goodman	ISO - New England	NPCC	2

Consideration of Comments on First Posting of MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability (Project 2007-09)

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10
11. Chantel Haswell	FPL Group, Inc.	NPCC 5										
12. David Kiguel	Hydro One Networks Inc.	NPCC 1										
13. Michael R. Lombardi	Northeast Utilities	NPCC 1										
14. Randy MacDonald	New Brunswick Power Transmission	NPCC 9										
15. Bruce Metruck	New York Power Authority	NPCC 6										
16. Lee Pedowicz	Northeast Power Coordinating Council	NPCC 10										
17. Robert Pellegrini	The United Illuminating Company	NPCC 1										
18. Si Truc Phan	Hydro-Quebec TransEnergie	NPCC 1										
19. Saurabh Saksena	National Grid	NPCC 1										
20. Michael Schiavone	National Grid	NPCC 1										
21. Wayne Sipperly	New York Power Authority	NPCC 5										
22. Donald Weaver	New Brunswick System Operator	NPCC 2										
23. Ben Wu	Orange and Rockland Utilities	NPCC 1										
24. Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC 3										
3. Group	Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X				

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

4. Group	Albert DiCaprio	IRC Standards Review Committee (joint comments)		X								

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

Consideration of Comments on First Posting of MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability (Project 2007-09)

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10
4. Mark Thompson	AESO	WECC 2										
5. Steve Myers	ERCOT	ERCOT 2										
5. Group	David Thorne	Pepco Holdings Inc Affiliates	X		X							
Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1. Carl Kinsley	Pepco Holdings Inc	RFC	1, 3									
2. Alivan Depew	Pepco Holdings Inc	RFC	1, 3									
6. Group	Jonathan Sykes, Chair	NERC System Protection and Control Subcommittee	X			X	X					X
No additional members listed.												
7. Group	Carol Gerou	Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	X	X	X	X	X	X				

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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
15. Scott Bos		Muscatine Power and Water	MRO 3, 4, 5, 6										
16. Lee Kittleson		Otter Tail Power Company	MRO 5, 1, 3, 6										
17. Marie Knox		Midwest ISO	MRO 2										
8.	Group	Jonathan Hayes	SPP Reliability Standards Development Team										

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

9.	Group	Charles W. Long	SERC Planning Standards Subcommittee	X									X

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

10.	Group	Tim Brown	Idaho Power-Power Production					X					

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

11.	Group	Terry L. Blackwell	Santee Cooper	X		X		X	X				

Consideration of Comments on First Posting of MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability (Project 2007-09)

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10
Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1. S. T. Abrams	Santee Cooper	SERC	1									
2. Phil Pierce	Santee Cooper	SERC	5									
3. Paul Camilletti	Santee Cooper	SERC	5									
4. Rene Free	Santee Cooper		1									
5. Tom Curtis	Santee Cooper	SERC	5									
12. Group	Annette Bannon	PPL Generation					X					
Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1. Leland McMillan	PPL Montana, LLC	WECC	5									
2. Don Lock	Lower Mount Bethel Energy, LLC	RFC	5									
3.	PPL Brunner Island, LLC	RFC	5									
4.	PPL Holtwood, LLC	RFC	5									
5.	PPL Martins Creek, LLC	RFC	5									
6.	PPL Montour, LLC	RFC	5									
13. Group	Louis Slade	Dominion	X		X		X	X				
Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1. Mike Garton		MRO	5, 6									
2. Connie Lowe		SERC	5, 6									
3. Michael Gildea		RFC	5, 6									
4. Larry Whanger		SERC	5									
5. Mike Crowley		SERC	1, 3									
6. Jeff Bailey		MRO	5									
14. Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				
Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1. Ed Baznik	FE	RFC	1									
2. Bill Duge	FE	RFC	5									

Consideration of Comments on First Posting of MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability (Project 2007-09)

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
3. Brian Orians		FE	RFC 5										
15.	Group	Joe Spencer - SERC Bob Jones - DRS chair	SERC Dynamics Review Sub-committee										X

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

16.	Group	Mallory Huggins	NERC Staff										

No additional members listed.

17.	Group	John Seelke	Public Service Enterprise Group	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ken Brown	PSE&G	RFC	1, 3
2.	Clint Bogan	PSEG Fossil	RFC	5
3.	Peter Dolan	PSEG ER&T	RFC	6
4.	Scott Slickers	PSEG Fossil	NPCC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
5. Eric Schmidt		PSEG ER&T	NPCC 6										
6. Mikhail Falkovich		PSEG Fossil	ERCOT 5										
18.	Group	Joe Spencer - SERC staff	SERC Generation sub-committee										X

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

19.	Group	Jason Marshall	ACES Power Members						X				

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

20.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
21.	Individual	Bo Jones	Westar Energy	X		X		X	X				

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

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

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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
64.	Individual	Oscar Herrera	Los Angeles Department of Water and Power	X		X		X	X				
65.	Individual	John Yale	Chelan County PUD	X				X	X				

1. The SDT has proposed that the requirements of MOD-024-1 and MOD-025-1 be combined into a single standard MOD-025-2. Do you agree with this approach? If not, please explain.

Summary Consideration: Most stakeholders agree with combining MOD-024-1 and MOD-025-1 into a single standard. Several commenters suggested that the standard be clarified to indicate that Real and Reactive testing may be performed under separate tests. The GVSDT agrees and separated R1 into two requirements to allow for separate Real and Reactive testing. The intent of these requirements remains unchanged. R1 now deals with Real Power testing only, while R2 deals with Reactive Power testing. The measure and VSL for R1 were also revised to match the requirements.

R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1.

1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.

R2. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

2.1. Verify the Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.

2.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.

A statement was also added to the beginning of Attachment 1:

"It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing, however separate testing is allowed for this standard. For synchronous condensers, perform only the Reactive Power capability verifications as specified below. If an applicable Facility is operated in synchronous condenser mode as well as generation mode, the unit should be verified in both modes."

Organization	Yes or No	Question 1 Comment
IRC Standards Review Committee (joint comments)	No	It is not a matter of whether the requirements for real power verification is in one numbered standard and reactive verification is in another numbered standard, the important point is that the requirements be clear and separate. The posted standard fails that test by combining two requirements into one. It may look cleaner writing the two together; the problem is with the fact that such a format has the potential to needlessly risk getting some data when the other data is NOT available. If an asset owner could provide real data but not reactive data, the standard as written would incent the owner from providing either data (why waste a test when the owner knows it will be non-compliant anyway? By separating the two actions, the owner would be compliant with one and non-compliant with the other requirement - but the planner would have at least half the information.
Response: The GVSDT thanks you for your comment. The GVSDT has separated R1 into two separate requirements for real and reactive testing. A statement was also added to the beginning of Attachment 1 stating, "It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing, however separate testing is allowed for this standard."		
PPL Generation	No	MOD-024 has already been incorporated into a regional standard by RFC (MOD-024-RFC); and, as is implicit in the term "standard," these documents should change only infrequently.
Response: The GVSDT thanks you for your comment. The GVSDT is coordinating with RFC regarding the regional standard. The following statement was provided by RFC and will be added to the implementation plan for MOD-025-2. "It is the intent of Reliability*First* to perform a review of both the MOD-024-RFC-01 and MOD-025-RFC-01 standards upon NERC Board of Trustees approval of the associated NERC MOD-025-2 standard. The purpose of the review would be to ensure that any duplicative requirements or any requirements which are less restrictive or do not add additional detail will be considered for retirement. The steps outlined in the Reliability*First* Reliability Standards Development Procedure will be followed for any such revisions or retirements."		
Associated Electric Cooperative, Inc.	No	Real power verification is typically done using historical operating data because units commonly operate at full real power capability. Reactive power verification will most likely not be done using historical operating data. This standard implies that these verifications will be done at the same time. Applicable standards should allow for real and reactive verifications at different times.
Response: The GVSDT thanks you for your comment. The GVSDT has separated R1 into two separate requirements for Real and Reactive testing. A statement was also added to the beginning of Attachment 1 stating, "It is intended that Real Power testing be performed at the same time as full load Reactive Power testing, however separate testing is allowed for this standard."		

Organization	Yes or No	Question 1 Comment
Exelon	No	The requirements of MOD-024-1 and MOD-025-1 should remain separate. The testing periodicities and the reporting requirements for both of the existing Standards are different. In addition, the SDT needs to closely coordinate with existing testing and reporting requirements 1) Regional requirements and reporting criteria (e.g., MOD-024-RFC-01.1) and 2) Transmission Planner requirements (e.g., PJM has separate reporting criteria).If the SDT continues to push for a combined Standard, then consideration must be given to splitting out the requirements (i.e., separate Attachments) for Real and Reactive Testing.
Response: The GVSDT thanks you for your comment. **1) The GVSDT is coordinating with RFC regarding the regional standard. The following statement was provided by RFC and will be added to the Implementation plan for MOD-025-2.** "It is the intent of Reliability*First* to perform a review of both the MOD-024-RFC-01 and MOD-025-RFC-01 standards upon NERC Board of Trustees approval of the associated NERC MOD-025-2 standard. The purpose of the review is to ensure that any duplicative requirements or any requirements which are less restrictive or do not add additional detail will be considered for retirement. The steps outlined in the Reliability*First* Reliability Standards Development Procedure will be followed for any such revisions or retirements." **2) Requirements other than NERC or regional standards are outside the scope of the GVSDT. The GVSDT has separated R1 into two separate requirements for Real and Reactive testing. A statement was also added to the beginning of Attachment 1 stating, "It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing, however separate testing is allowed for this standard."**		
Wisconsin Electric	No	The testing of reactive power capability has inherent risks due to the need for coordination with relaying and excitation limiters, and requires more technical resources than real power testing. Therefore the verification of real and reactive power would best be addressed in separate standards.
Response: The GVSDT thanks you for your comment. The GVSDT has separated R1 into two separate requirements for Real and Reactive testing. We believe that this change will address your concern. A statement was also added to the beginning of Attachment 1 stating, "It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing, however separate testing is allowed for this standard."		
Indeck Energy Services	No	Testing will be more difficult if combined.
Response: The GVSDT thanks you for your comment. The GVSDT has separated R1 into two separate requirements for Real and Reactive testing. A statement was also added to the beginning of Attachment 1 stating, "It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing, however separate testing is allowed for this standard."		

Organization	Yes or No	Question 1 Comment
FirstEnergy	Yes	We agree that a “one-stop-shop” approach is appropriate for Real and Reactive Generator Verification requirements.
Response: The GVSDT thanks you for your comment.		
SERC Dynamics Review Sub-committee	Yes	Consolidating standards is beneficial
Response: The GVSDT thanks you for your comment.		
SERC Generation sub-committee	Yes	Please clarify if real and reactive verification can be performed at different times.
Response: The GVSDT thanks you for your comment. The GVSDT has separated R1 into two separate requirements for Real and Reactive testing. The tests can be performed separately. A statement was also added to the beginning of Attachment 1 stating, “It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing, however separate testing is allowed for this standard.”		
Cowlitz County PUD	Yes	Combination of closely related standards simplifies compliance program development, and is welcome.
Response: The GVSDT thanks you for your comment.		
American Electric Power	Yes	In general, AEP is not opposed to combining MOD-024-1 and MOD-025-1 into a single MOD-025-2 standard.
Response: The GVSDT thanks you for your comment.		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration LP agrees that generator reactive testing necessarily requires validation at the real power extremes. This means there is no benefit to require separate testing.
Response: The GVSDT thanks you for your comment.		
Duke Energy	Yes	Yes, however need to define "Rated Real Power" so that entities are using a consistent basis for data reporting. MW validation is intrinsically connected to governor response issues and thus should be instead be combined with MOD-27 frequency response efforts and the following modeling parameters defined and

Organization	Yes or No	Question 1 Comment
		addressed:- Pmax o The continuous operating limit o The ultimate max emergency output. o Should there consider weather conditions (summer or winter, etc.). o PMAX associated with Transient stability - is it the same as for LF o Is this on the order of 105% or 110% or ??% of normal max loading. Please clarify if real and reactive verification can be performed at different times.
Response: The GVSDT thanks you for your comment. To address your concern, Step 2.1 of Attachment 1 was modified by adding the phrase "(not emergency)" to the first sentence; which states, "The generating unit's normal (not emergency) expected maximum Real Power at the time of the verification." **The tests can be performed separately.**		
Lincoln Electric System	Yes	Yes, but the verification periods should be different for Real and Reactive Power. It is not unreasonable to expect a Real Power verification test on an annual basis, as this data is usually available annually at some time when the unit is operated to serve load. It states the purpose of the Project 2007-09 Generator Verification is: "To ensure that generator models accurately reflect the generator's capabilities and operating characteristics." Without annual operation to verify Real Power it appears difficult to ensure this objective with a high degree of confidence.
Response: The GVSDT thanks you for your comment. The GVSDT has separated R1 into two separate requirements for Real and Reactive testing. A statement was also added to the beginning of Attachment 1 stating, "It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing, however separate testing is allowed for this standard." **Regarding periodicity, the verification data is being utilized for the planning time horizon; and as such, the GVSDT believes that there is little, if any, reliability benefit associated with performing more frequent Real Power verification.**		
Independent Electricity System Operator	Yes	We support this approach. The real and reactive power capabilities are related and hence having them addressed in one standard would enhance verification efficiency.
Response: The GVSDT thanks you for your comment.		

Consideration of Comments on First Posting of MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability (Project 2007-09)

Organization	Yes or No	Question 1 Comment
Indiana Municipal Power Agency	Yes	IMPA supports combining MOD-024-1 and MOD-025-1 into a single standard MOD-025-2.
Response: The GVSDT thanks you for your comment.		
Northeast Power Coordinating Council	Yes	
Imperial Irrigation District (IID)	Yes	
Pepco Holdings Inc Affiliates	Yes	
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	
SPP Reliability Standards Development Team	Yes	
SERC Planning Standards Subcommittee	Yes	
Idaho Power-Power Production	Yes	Yes
Santee Cooper	Yes	
Dominion	Yes	
NERC Staff	Yes	
Public Service Enterprise Group	Yes	
ACES Power Members	Yes	

Consideration of Comments on First Posting of MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability (Project 2007-09)

Organization	Yes or No	Question 1 Comment
Arizona Public Service Company	Yes	
Westar Energy	Yes	
Southern Company	Yes	
Tennessee Valley Authority GO	Yes	
Luminant Power	Yes	
Lakeland Electric	Yes	
Salt River Project	Yes	
PacifiCorp	Yes	
South Carolina Electric and Gas	Yes	
APS		being intentionally left blank (no answer to be provided)
Dynegy Inc.	Yes	
New York Independent System Operator	Yes	
Tri-State Generation and Transmission, In.	Yes	
Xcel Energy	Yes	
Lakeland Electric	Yes	
American Wind Energy	Yes	

Organization	Yes or No	Question 1 Comment
Association		
Tacoma Power	Yes	
Georgia Transmission Corporation	Yes	
Austin Energy	Yes	
Great River Energy	Yes	
BC Hydro	Yes	
Northeast Utilities	Yes	
Constellation Power Generation	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	
Wisconsin Public Service Corp	Yes	
GE Energy	Yes	
ISO New England	Yes	
GenOn Energy	Yes	
Manitoba Hydro	Yes	
Gainesville Regional Utilities	Yes	
Ameren	Yes	

Organization	Yes or No	Question 1 Comment
Oncor Electric Delivery Company LLC	Yes	
Chelan County PUD	Yes	
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.

2. The SDT has proposed that the data from MOD-025-2 be submitted to the Transmission Owner. Do you believe the Transmission Owner is the appropriate entity to receive this data? If not, please explain.

Summary Consideration: There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. Most stakeholders suggested that the Transmission Planner is the appropriate entity to receive the data required by MOD-025-1. A few commenters suggested that the information should be provided to other reliability entities, such as the Reliability Coordinator. As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the planning and Real-time time horizons. Per the NERC Reliability Functional Model (V5, Page 25), the Transmission Planner has the following relationships with other entities:

2. Collects information including:

c. Generator unit performance characteristics and capabilities from Generator Owners.

5. Coordinates the evaluation of BES expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.

6. Reports on and coordinates its BES expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers.

The GVSDT has not revised the requirement with respect to submitting the data to the Transmission Planner. The requirement continues to require the data be submitted to the Transmission Planner.

Organization	Yes or No	Question 2 Comment
LG&E and KU Energy	No	Either the Planning Authority of the Transmission Planner are the more likely entity to submit data rather than the Transmission Owner as indicted in R2.3
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. You are correct that the Transmission Planner is the appropriate entity to receive the data required by MOD-025-1.		
Northeast Power Coordinating	No	The Transmission Operator (TOP) and Transmission Planner (TP) are far more likely to need and use the

Organization	Yes or No	Question 2 Comment
Council		data and models identified and dispatch the units in their market area. In New York, the NYISO as the TOP is responsible for real-time modeling and dispatch (specifying both real and reactive schedules), and as TP the longer term modeling. The Transmission Owners (TO's) do not have this type of relationship with the Generation Owners (GO's) and Generation Operators (GOP's). R1: A standard should be developed that makes reactive power testing mandatory for all units above 75 MVA. This standard will provide the TOP with critical information on the total dynamic reactive capability of dispatched generation.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. Most stakeholders suggested that the Transmission Planner is the appropriate entity to receive the data required by MOD-025-1. A few commenters suggested that the information should be provided to other reliability entities such as the Reliability Coordinator or Transmission Operator. As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the planning and Real-time operations time horizons. Per the NERC Reliability Functional Model (V5, Page 25), the Transmission Planner has the following relationships with other entities: **2. Collects information including:** **c. Generator unit performance characteristics and capabilities from Generator Owners.** **5. Coordinates the evaluation of BES expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.** **6. Reports on and coordinates its BES expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers.**		
IRC Standards Review Committee (joint comments)	No	MOD-025 is a requirement on owners to verify data, nowhere does the requirement state who the data goes to. Of course the owner is NOT the appropriate entity to send the data to since they are the ones that are responsible for generating the information. This standard has many issues related to who gets what data and why. There is no requirement to have the data in the first place. The standard would be better to require a planning entity to request the data that that entity needs to do its mandated functions. Once the planner asks for the data, then the owner can provide / verify the information being asked for. The SDT has rejected the comments that other standards already provide this information. The SDT has parsed the terms "capability" and "rating". However, the NERC Glossary defines Rating as strictly a transmission line term, and the word capability is not defined. Capability does show up within other

Organization	Yes or No	Question 2 Comment
		definitions related to Transfers and other transmission terms. The SDT is asked to review their findings in light of the above, and in light of the FAC and TOP standards purposes. The TOP standard has developed the flexible approach of having an entity ask for the data it needs, and for the receiver of the request to provide the needed information. This approach eliminates the idea of a common requirement for all planners (whether or not they want the data elements in the posted Attachment 2).Our proposal is to have a requirement (if it does not already exist) mandating entities asks for what they want, and a separate requirement for the receivers to provide just that data. If the revised standard is written in that fashion than the new MOD-025 COULD replace the old MOD-024 because there would be no need to specify reactive data from real data, because the entities who are asking for the data will do that for you. Editorial :(1) The receiving entity cited in this question (Transmission Owner) seems different than the entity indicated in the standard (Transmission Planner). If it is not a typo, then we may be missing something. Regardless, we commented previously (on MOD-024-2) on a related subject in which we indicated that given the purpose of the standard, which now reads: “To ensure that planning entities have accurate generator Real and Reactive Power capability data when assessing Bulk Electric System (BES) reliability”, we believe that the data is used for planning assessments that could entail both resource adequacy and transmission reliability, and may even include short or near-term transmission reliability assessments. In view of the facility ownership and potential users, submitting the data to the Transmission Owner does not seem to be logical from the following standpoints: a. The TO does not own the generators and may not actually use the data at all if it does not perform transmission planning assessments; b. The Transmission Planner is the entity that conducts transmission planning assessments; c. Other planning entities that use this data are the Planning Coordinators and Resource Planners. For the above reasons, a more logical entity to receive this data and be the one that requests for data is made by other entities that have a need for the data such as Transmission Planners, Resource Planners, Reliability Coordinator and Transmission Operator, would be the Planning Coordinator. We suggest to change Transmission Owner to Planning Coordinator. (2) And also in view of the potential use of this data, we suggest the purpose of the standard be reverted back to its previous version: “To ensure accurate information on generator gross and net Real Power capability is available for steady-state models used to assess Bulk Electric System reliability.”, or be revised to: “To ensure that [the word planning removed] entities have accurate generator Real and Reactive Power capability data when assessing Bulk Electric System (BES) reliability”.
Response: The GVSDT thanks you for your comment.		

Organization	Yes or No	Question 2 Comment
(First paragraph) The GVSDT points out that Requirement R1, Parts 1.3 and 2.3 both specify that the responsible entity shall, "Submit within 90 calendar days of the date the data is recorded to its Transmission Planner." **(Second Paragraph) The GVSDT has revised the MOD-024-1 and MOD-025-1 planning standards. Early in the project, the GVSDT considered the approach suggested of having entities requiring the verified data to also specify the data that they require. This approach was universally opposed by the members of the GVSDT who work in Transmission Planning because (1) it is common knowledge that Real and Reactive Power data is required, and (2) any communication requesting data from the generating entity will need to be documented and verified; which is a burdensome task without reliability benefit.** **(Editorial 1) There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the operations planning and Real-time operations time horizons. Per the NERC Reliability Functional Model (V5, Page 25), the Transmission Planner has the following relationships with other entities:** **2. Collects information including:** **c. Generator unit performance characteristics and capabilities from Generator Owners.** **5. Coordinates the evaluation of BES expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.** **6. Reports on and coordinates its BES expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers.** **The GVSDT believes that the Transmission Planner is the appropriate entity.** **(Editorial 2) The purpose statement has been revised to:** **1.** To ensure accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess BES (BES) reliability.		
Independent Electricity System Operator	No	(1) The receiving entity cited in this question (Transmission Owner) seems different than the entity indicated in the standard (Transmission Planner). If it is not a typo, then we may be missing something. Regardless, we commented previously (on MOD-024-2) on a related subject in which we indicated that given the purpose of the standard, which now reads: "To ensure that planning entities have accurate generator Real and Reactive Power capability data when assessing Bulk Electric System (BES) reliability", we believe that the data is used for planning assessments that could entail both resource adequacy and transmission reliability, and may even include short or near-term transmission reliability assessments. In view of the facility ownership

Organization	Yes or No	Question 2 Comment
		and potential users, submitting the data to the Transmission Owner does not seem to be logical from the following standpoints: a. The TO does not own the generators and may not actually use the data at all if it does not perform transmission planning assessments; b. The Transmission Planner is the entity that conducts transmission planning assessments; c. Other planning entities that use this data are the Planning Coordinators and Resource Planners. For the above reasons, a more logical entity to receive this data and be the one that requests for data is made by other entities that have a need for the data such as Transmission Planners, Resource Planners, Reliability Coordinator and Transmission Operator, would be the Planning Coordinator. We suggest to change Transmission Owner to Planning Coordinator. (2) And also in view of the potential use of this data, we suggest the purpose of the standard be reverted back to its previous version: "To ensure accurate information on generator gross and net Real Power capability is available for steady-state models used to assess Bulk Electric System reliability.", or be revised to: "To ensure that [the word planning removed] entities have accurate generator Real and Reactive Power capability data when assessing Bulk Electric System (BES) reliability".

Response: The GVSDT thanks you for your comment. Please see responses above.

(Section 1) There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the operations planning and Real-time operations time horizons. Per the NERC Reliability Functional Model (V5, Page 25), the Transmission Planner has the following relationships with other entities:

2. Collects information including:

c. Generator unit performance characteristics and capabilities from Generator Owners.

5. Coordinates the evaluation of BES expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.

6. Reports on and coordinates its BES expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource

Organization	Yes or No	Question 2 Comment
Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers. **The GVSDT believes that the Transmission Planner is the appropriate entity.** **(Section 2) The purpose statement has been revised to:** **1.** To ensure accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess BESreliability. .		
Pepco Holdings Inc Affiliates	No	The standard in Sec B-R1.3 and R2.3 state to submit the data to the TP not the TO. The TP is the appropriate entity. However, the TOP and the TOP also have need of the data. Should dissemination to these entities be covered in the requirements also?
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the operations planning and Real-time operations time horizons.		
NERC System Protection and Control Subcommittee		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	No	The standard states that the data be submitted to the Transmission Planner and we agree with that approach.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
SPP Reliability Standards Development Team	No	Is there a typo in the question? Should Transmission Owner be Transmission Planner? If not then adding the Transmission Owner as an intermediate step before submitting data to the Transmission Planner isn't needed.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		

Organization	Yes or No	Question 2 Comment
SERC Planning Standards Subcommittee	No	The PSS believes that the Transmission Planner (TP) should receive this information initially (which is what the standard currently requires).
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
PPL Generation	No	PPL Generation, LLC's Registered Entities are already performing VAR testing and reporting the results to our RTO (PJM), in accordance with Manual PJM-14D, and PJM then makes this information available to other entities. It would be very confusing to have to conduct two different VAR tests (PJM and NERC), possibly resulting in two different values (depending on the final wording of MOD-025), reported to two different entities.
Response: The GVSDT thanks you for your comment. The GVSDT is not aware of the testing required by PJM. If the testing requirements are the same, then a single test could be performed and reported to satisfy both PJM and NERC requirements.		
Dominion	No	R1.3 and R2.3 require submittal to Transmission Planner, not Transmission Owner. We believe it is also appropriate to submit these results to the Resource Planner as we are unaware of an existing reliability standard that requires this information be provided to that entity (even though aware that version 5 of the Functional Model (on page 28) states the Resource Planner "Coordinates with Transmission Planners, Transmission Service Providers, Reliability Coordinators, and Planning Coordinators on resource adequacy plans."Further, we believe it is also appropriate to submit these results to the Balancing Authority and Transmission Operator despite the fact that they may request verification pursuant to TOP-002a @R13. We believe that, given the owner is being required to verify real and reactive capability, and report the results to one entity, requiring reporting to additional entities who could find the information useful in its reliability assessment (whether in the planning or operating time horizon) adds significant value at little additional effort.
Response: The GVSDT thanks you for your comment. **(First part) There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.** **(Second part)** As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by		

Organization	Yes or No	Question 2 Comment
other entities. The TP then hands these models off to entities that are concerned with the operations planning and Real-time operations time horizons.		
FirstEnergy	No	The standard in Subpart 1.3 says that the Transmission Planner is the entity that shall receive this information. We agree that it should be the TP. Also, we question whether or not the Planning Coordinator should also receive this information. Furthermore, with respect to how this information will be used by the planning entities, the team needs to assure that there is no duplication of efforts with MOD-010-0 and MOD-011-0. We suggest that MOD-010-0 and MOD-011-0 get revised to remove redundancies, or make it clear that the entity may supply existing MOD-010/-011 compliance evidence to show compliance with MOD-025-2.
Response: The GVSDT thanks you for your comment. Please see responses above. **(First part) There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.** **(Second part) MOD-010-0 and MOD-011-0 pertain to data and equipment characteristics, not validation requirements; therefore, the standards do not duplicate requirements.**		
SERC Dynamics Review Sub-committee	No	The DRS believes that the Transmission Planner (TP) should receive this information initially (which is what the standard currently requires).
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
NERC Staff	No	Requirement R1, part 1.3 and Requirement R2, part 2.3 indicate that data is to be submitted to the Transmission Planner. We agree that the data should be submitted to the Transmission Planner, not the Transmission Owner. Further, we believe that the data should be provided to all entities that have need of the data, including the Transmission Operators and Reliability Coordinators who need the data for their operational planning and real-time models.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the operations planning and Real-time operations time horizons. Per the NERC Reliability Functional Model (V5, Page 25), the Transmission Planner		

Organization	Yes or No	Question 2 Comment
has the following relationships with other entities: 2. Collects information including: c. Generator unit performance characteristics and capabilities from Generator Owners. 5. Coordinates the evaluation of BES expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners. 6. Reports on and coordinates its BES expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers. The GVSDT believes that the Transmission Planner is the appropriate entity.		
Public Service Enterprise Group	No	MOD-025-2 requires that data be submitted by GOs or TOs to their respective Transmission Planner (R2.3). It should not require that it be submitted to the Transmission Owner as the TO has no need for this data.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
SERC Generation sub-committee	No	The TP or the PC (PA) is the entity needing the data, rather than the TO. R1.3 and R2.3 specifies that the TP be given this data.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
ACES Power Members	No	The requirements appear to correctly show the data being submitted to the TP. However, Transmission Owner in 3.4 of Attachment 1 should be Transmission Planner.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. Attachment 1, Step 3.4 was revised to change responsibility from the Transmission Owner to the Generator Owner. This adjustment is made before the data is sent to the Transmission Planner.		
South Carolina Electric and Gas	No	SCE&G believes that the Transmission Planner (TP) should receive this information, consistent with the current version of the standard.

Organization	Yes or No	Question 2 Comment
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
Associated Electric Cooperative, Inc.	No	The TP or PA seems more appropriate.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
New York Independent System Operator	No	In section B, R1.3, results are required to be submitted to the Transmission Planner. The NYISO agrees with R1.3.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
Westar Energy	No	We agree data should be submitted to the Transmission Planner as written in the draft of the standard.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
Southern Company	No	The TP or the PC is the entity who needs the data, not the TO. R1.3 and R2.3 specifies that the TP be given this data.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
Tennessee Valley Authority GO	No	The TP or the PC (PA) is the entity who will use the data. R1.3 and R2.3 specifies that the TP be given this data.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
Luminant Power	No	This is not applicable in the ERCOT region. Data should be submitted to TOP and BA. They are currently responsible to utilizing the information for grid reliability.

Organization	Yes or No	Question 2 Comment
Response: The GVSDT thanks you for your comment. MOD-025-2 is a long-term planning standard. The TOP and BA entities do not perform long-term planning functions.		
Cowlitz County PUD	No	Not all Transmission Owners have a complete system view of the BES, let alone modeling software. The standard as written specifies the Transmission Planner, and so the question appears to be in error. Following the purpose statement of the standard, the Planning Coordinator (formerly Planning Authority) might also need the data along with the Transmission Planner. To further complicate the matter, in WECC CUG meetings it has been brought up that entities are experiencing difficulty in identifying their Planning Coordinator and Transmission Planner. Such entities have been rebuffed when approaching the obvious candidates. Therefore, Cowlitz suggests that a mechanism must be devised such that Generator Owners will not left in a compliance quandary in their endeavors to identify the appropriate planner(s).
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the operations planning and Real-time operations time horizons. Per the NERC Reliability Functional Model (V5, Page 25), the Transmission Planner has the following relationships with other entities: **2. Collects information including:** **c. Generator unit performance characteristics and capabilities from Generator Owners.** **5. Coordinates the evaluation of BES expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.** **6. Reports on and coordinates its BES expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers.** **The GVSDT believes that the Transmission Planner is the appropriate entity. The GVSDT suggest contacting your regional Entity for help identifying your Planning Coordinator and Transmission Planner.**		
Exelon	No	The Transmission Planner should be the appropriate entity to receive this data.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
Georgia Transmission	No	This question seems to have identified the TO in error. MOD025-2 requires data to be submitted to the TP.

Organization	Yes or No	Question 2 Comment
Corporation		TP is the appropriate entity to receive the data.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
Austin Energy	No	We believe question #2 may contain a typo. The Proposed Standard Requirement 1.3 correctly requires data submittal to the Transmission PLANNER (in our case ERCOT). The data should be submitted to the Transmission Planner as currently written in the Proposed Standard, not the Transmission Owner as stated in the comment questionnaire.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
BC Hydro	No	Not clear why data would be submitted to TO. Based on Functional Model, TP, TOP or PC would be more applicable.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
Northeast Utilities	No	The Transmission Operator (TOP) and Transmission Planner (TP) are far more likely to need and use the data and models identified and dispatch the units in their market area. In New York, the NYISO as the TOP is responsible for real-time modeling and dispatch (specifying both real and reactive schedules), and as TP the longer term modeling. The Transmission Owners (TO's) do not have this type of relationship with the Generation Owners (GO's) and Generation Operators (GOP's). R1: A standard should be developed that makes reactive power testing mandatory for all units above 75 MVA. This standard will provide the TOP with critical information on the total dynamic reactive capability of dispatched generation.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. **The standard applies to units greater than 20 MVA directly connected to the bulk power system.**		
Consolidated Edison Co. of NY, Inc.	No	The Transmission Operator (TOP) and Transmission Planner (TP) are far more likely to need and use the data and models identified and dispatch the units in their market area. In New York, the NYISO as the TOP is

Organization	Yes or No	Question 2 Comment
		responsible for real-time modeling and dispatch (specifying both real and reactive schedules), and as TP the longer term modeling. The Transmission Owners (TO's) do not have this type of relationship with the Generation Owners (GO's) and Generation Operators (GOP's). R1: A standard should be developed that makes reactive power testing mandatory for all units above 75 MVA. This standard will provide the TOP with critical information on the total dynamic reactive capability of dispatched generation.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. The standard applies to units greater than 20 MVA directly connected to the bulk power system.		
Ingleside Cogeneration LP	No	Cogeneration LP believes that the proper recipient is the Transmission Planner. The Transmission Planner in turn must supply the information to the Planning Authority, Reliability Coordinator, and/or Transmission Operator as needed. There is no apparent reason why the Transmission Owner should be in the loop. Attachment 1, Item 3.4 seems to be the only place in MOD-025-2 that the Transmission Owner is shown as the recipient of generator verification data. It should be changed to Transmission Planner - consistent with the rest of the standard.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
ISO New England	No	The data from MOD-25-2 should be submitted to the Transmission Operator. The Transmission Owner does not appear to be the correct functional entity. The Transmission Owner may not have the area view required for this testing. Real and Reactive Power Testing must be coordinated with the Transmission Operator to ensure that the system remains within all operating limits.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. MOD-025-2 is a long-term planning standard.		
Duke Energy	No	The TP or the PC (PA) is the entity needing the data, rather than the TO. R1.3 and R2.3 specifies that the TP be given this data. Both the TPs and Transmissions Operations entities need to have accurate model information and the Operating studies are much more critical for BES reliability.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should		

Organization	Yes or No	Question 2 Comment
have asked if the Transmission Planner was the appropriate entity.		
CPS Energy	No	The Transmission Planner is the appropriate entity to use the data.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
Ameren	No	Both the Transmission Owner and Transmission Planner should receive it.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. Per the NERC Reliability Functional Model (V5, Page 24), the Transmission Planner has the following relationships with other entities: **2. Collects information including:** **c. Generator unit performance characteristics and capabilities from Generator Owners.** **5. Coordinates the evaluation of BES expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.** **6. Reports on and coordinates its BES expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers.** **The GVSDT believes that the Transmission Planner is the appropriate entity.**		
Indeck Energy Services	No	TP
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
Oncor Electric Delivery Company LLC	No	In the ERCOT Region, Oncor believes that the appropriate entity to receive this information is the Planning Authority.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the operations planning and Real-time operations time horizons. Per the NERC Reliability Functional Model (V5, Page 25), the Transmission Planner has		

Organization	Yes or No	Question 2 Comment
the following relationships with other entities: **2. Collects information including:** **c. Generator unit performance characteristics and capabilities from Generator Owners.** **5. Coordinates the evaluation of BES expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.** **6. Reports on and coordinates its BES expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers.** **The GVSDT believes that the Transmission Planner is the appropriate entity.**		
Indiana Municipal Power Agency	No	According to VAR-002-1, the Transmission Operator is responsible for providing the voltage schedule to the Generator Operator. This voltage schedule is to ensure generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained. It seems like the TOP should know what the generating units are capable of producing when it comes to reactive power. IMPA recommends adding the TOP entity to the requirement 1.3.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. MOD-025-2 is a long-term planning standard. It is inappropriate to include operating entities as applicable entities under MOD-025-2.		
Lakeland Electric	Yes	A Transmission Owner may need to size conductors according to Generator output.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. Your concern is addressed by the Interconnection agreements between TOs and GOs.		
Tri-State Generation and Transmission, In.	Yes	The standard also calls for the data to be submitted to the Transmission Planner, so this question seems ambiguous.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
American Electric Power	Yes	Draft Standard MOD-025-2 provisions 1.3 and 2.3 both state that the data be provided to the Transmission Planner, rather than the Transmission Owner as stated within this question #2. We agree that the

Organization	Yes or No	Question 2 Comment
		Transmission Planner is the correct recipient for this data.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
Arizona Public Service Company	Yes	
Imperial Irrigation District (IID)	Yes	
Idaho Power-Power Production		Yes
Santee Cooper	Yes	
Salt River Project	Yes	
PacifiCorp	Yes	
Xcel Energy	Yes	
Lakeland Electric	Yes	
Wisconsin Electric	Yes	
Great River Energy	Yes	
Dynegy Inc.	Yes	
American Wind Energy Association	Yes	
Tacoma Power	Yes	
Wisconsin Public Service Corp	Yes	

Organization	Yes or No	Question 2 Comment
Constellation Power Generation	Yes	
GenOn Energy	Yes	
Gainesville Regional Utilities	Yes	
Manitoba Hydro	Yes	
Chelan County PUD	Yes	
APS		being intentionally left blank (no answer to be provided)
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.

3. The SDT has proposed that the ambient temperature during the verification be provided to the Transmission Owner, as well as a correction factor to allow the Transmission Owner to adjust the Real Power data to a different ambient temperature, if needed. Do you feel the standard should require that the Real Power data submitted be temperature-adjusted to some other-than-ambient temperature? If yes, please explain and include which entity you think should perform the correction and which entity should determine the temperature value that should be used for the correction.

Summary Consideration: Many commenters pointed out there are many factors that affect generator Real Power output, and these factors are different for different types of generating units. The SDT modified the standard to assign responsibility for making the ambient condition (including ambient temperature) adjustments to the Generator Owner, rather than the Transmission Owner. The GVSDT has revised the standard to include any parameter that the GO determines is required to make ambient correction in Attachment 1:

> 3.4. The ambient conditions, if applicable, at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:
>
> - Ambient air temperature
> - Relative humidity
> - Cooling water temperature

The standard gives the Transmission Planner the discretion to request ambient condition correction at time of verification.

Organization	Yes or No	Question 3 Comment
IRC Standards Review Committee (joint comments)	No	See comment to Q2. The planner should ask for the data that it needs to comply with NERC standards (nothing more and nothing less). There is no need for the requirement to get into the details. The Planning standards will force the Planner to ask for the data that it needs for its models. This approach limits the Planners from asking for data that they do not use in their Planning Models or that is not needed to comply with a NERC standard. This approach also allows the Planner to tailor its requests to the Models and technologies that it has and needs. (1) We do not support the notion that a Transmission Owner has the technical expertise to adjust a generator's real power capability to reflect a difference in ambient temperature. If anyone, it should be the

Organization	Yes or No	Question 3 Comment
		Generator Owner. (2) Reporting the ambient temperature is unnecessary since it is only one of the many factors that could affect the real power output of a generator. Adjusting the real power capability for a different ambient temperature does not really provide a more accurate value, and can be misleading. (3) Notwithstanding the concerns expressed above, to make such an adjustment with some degree of accuracy, the responsible entity needs to have the information on that capability which corresponds to the ambient temperature for which the adjustment is to be made. It thus suggests that a capability-temperature curve be first established to provide credible references, implying that the Generator Owners must conduct a series of verification tests under different ambient temperature conditions. This is overly cumbersome, and creates unnecessary burden to the GOs. We suggest that this requirement be removed from Attachment 1.
Response: The GVSDT thanks you for your comment. Early in the project, the GVSDT considered the approach suggested of having entities requiring the verified data to also specify the data that they require. This approach was universally opposed by the members of the GVSDT who work in Transmission Planning because (1) it is common knowledge that Real and Reactive Power data is required, and (2) any communication requesting data from the generating entity will need to be documented and verified; which is a burdensome task without reliability benefit. **The SDT modified the standard to assign responsibility for making the ambient condition (including ambient temperature) adjustments, if applicable, to the Generator Owner in support of your suggestion.** **There are many factors that affect generator Real Power output, and these factors are different for different types of generating units. The reason why the GVSDT incorporated temperature correction consideration into the draft standard is because most Planners specify ambient temperature conditions when performing planning case studies.**		
Independent Electricity System Operator	No	(1) We do not support the notion that a Transmission Owner has the technical expertise to adjust a generator's real power capability to reflect a difference in ambient temperature. If anyone, it should be the Generator Owner. (2) There seems to be little value in reporting the ambient temperature for the purpose of making adjustments to measured Real Power capability since it is only one of the several factors that could affect the real power output of a generator. (3) Notwithstanding the concerns expressed above, to make such an adjustment with some degree of accuracy, the responsible entity needs to have the information on that capability which corresponds to the ambient temperature for which the adjustment is to be made. It thus suggests that a capability-temperature curve be first established to provide credible references, implying that the Generator Owners must conduct a series of verification tests under different ambient temperature conditions. This is overly cumbersome, and creates unnecessary burden to the GOs. We suggest that this requirement be removed from Attachment 1.

Organization	Yes or No	Question 3 Comment
Response: The GVSDT thanks you for your comment. The SDT modified the standard to assign responsibility for making the ambient condition (including ambient temperature) adjustments to the Generator Owner in support of your suggestion. **The reason why the GVSDT incorporated temperature correction consideration into the draft standard is because most Planners specify ambient temperature conditions when performing planning case studies. The GVSDT believes that Transmission Planners have sufficient expertise to properly apply temperature correction factor information provided by the GO. All data needed for adjusting MW capability is now required in Attachment 2 per FERC Order 693, Paragraph 1310.** **The GVSDT does not intend for entities to perform multiple tests. Instead, the GO simply provides a temperature correction factor with test data collected. As a matter of practicality, temperature correction factor information should already be captured as part of the internal process used for performing Real Power testing.** **Temperature correction is only intended to be applied during engineering analysis of collected data. Additional testing is not required or necessary.**		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	No	We recommend that in Item 3.4 of Attachment 1 the wording be changed from "to allow the Transmission Owner" to "to allow the Transmission Planner". We support the position that the ambient temperature at the end of the verification period and the correction factor should be provided to the Transmission Planner so that the Transmission Planner can adjust the verification results to the ambient temperature that is appropriate for its system planning assessments.
Response: The GVSDT thanks you for your comment. Item 3.4 in Attachment 1 provides guidance with respect to correction factors and has been revised to assign responsibility for making a temperature correction, if applicable, to the Generator Owner rather than the Transmission Owner: **3.4. The ambient conditions, if applicable, at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:** • **Ambient air temperature** • **Relative humidity** • **Cooling water temperature**		
PPL Generation	No	The correction of real power capability to other-than-tested ambient conditions, as is currently performed by PPL Generation Registered Entities for MOD-024-RFC, is a complex matter involving the wet-bulb temperature, condenser cleanliness and other factors beyond simply the dry-bulb temperature, especially when using a total-unit thermodynamic computer model for this purpose. One must also consider low-

Organization	Yes or No	Question 3 Comment
		ambient limitations; wintertime predicted capabilities must be truncated if they would otherwise exceed the generator or GSU rating. Corrections to other-than-tested ambients should be performed by the GO, using an on-request basis.
Response: The GVSDT thanks you for your comment. Early in the project, the GVSDT considered the approach suggested of having entities requiring the verified data to also specify the data that they require. This approach was universally opposed by the members of the GVSDT who work in Transmission Planning because (1) it is common knowledge that Real and Reactive Power data is required, and (2) any communication requesting data from the generating entity will need to be documented and verified; which is a burdensome task without reliability benefit. **There are many factors that affect generator Real Power output, and these factors are different for different types of generating units. The reason why the GVSDT incorporated temperature correction consideration into the draft standard is because most Planners specify ambient temperature conditions when performing planning case studies.** **The GO can include any or all of the factors mentioned in the comment when providing data correction factor information. The SDT modified the standard to assign responsibility for making the ambient condition (including ambient temperature) adjustments, if requested, to the Generator Owner in support of your suggestion.**		
Idaho Power-Power Production	No	No
LG&E and KU Energy		GO's typically correct to back pressure. Any other adjustments should be performed by Transmission Operator
Response: The GVSDT thanks you for your comment. There are many factors that affect generator Real Power output, and these factors are different for different types of generating units. The reason why the GVSDT incorporated temperature correction consideration into the draft standard is because most Planners specify ambient temperature conditions when performing planning case studies. Since the GO will not know the temperature as specified by the Planner for a particular scenario, the GVSDT believes the best solution for this concern is to have the GO record the ambient temperature at time of verification and also provide correction factor information so the Planner can extrapolate data to a different temperature basis when performing studies. The SDT modified the standard to assign responsibility for making the ambient condition (including ambient temperature) adjustments to the Generator Owner, rather than the Transmission Owner.		
FirstEnergy	No	We believe that it is the responsibility of the Generator Owner to have an appropriate Ambient Adjustment Methodology and make the necessary corrections to the data per its methodology before submitting it to the Transmission Owner. We suggest similar requirement regarding ambient adjustments as found in regional standards MOD-024-RFC-01 and MOD-025-RFC-01.

Organization	Yes or No	Question 3 Comment
Response: The GVSDT thanks you for your comment. The GVSDT has revised the standard to capture additional ambient condition parameters which could be used for correction in addition to ambient air temperature; however, the requirements are less stringent than required by the RFC standard. As specified by the NERC Rules of Procedure, regional standards can incorporate more stringent requirements than required by NERC, if necessary, for regional reliability. **The SDT did modify the standard to assign responsibility for making ambient condition (including ambient temperature) adjustments to the Generator Owner rather than the Transmission Owner.**		
SERC Dynamics Review Sub-committee	No	This provides all the information needed to allow the TO to rate the machines at whatever ambient temperature may be needed. Per #2, the DRS recommends that TO be changed to TP. In attachment 1 item 3.4, the DRS recommends that "correction factor" be changed to "adjustment method," to allow real power determination at multiple temperatures.
Response: The GVSDT thanks you for your comment. The SDT modified the standard (Attachment 1, Step 3.4) to assign responsibility for making the ambient condition (including ambient temperature) adjustments to the Generator Owner rather than the Transmission Owner. The language of 3.4 in Attachment 1 was revised to "perform corrections to Real Power for different ambient conditions."		
NERC Staff	No	It is not necessary to specify a temperature for which submitted data should be adjusted because one temperature will not be appropriate for all regions or for all types of studies. Providing the recorded value and a temperature correction factor or correction table is appropriate.
Response: The GVSDT thanks you for your comment. The GVSDT agrees with your comment and has revised item 3.4 in Attachment 1 to: **3.4. The ambient conditions, if applicable, at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:** • **Ambient air temperature** • **Relative humidity** • **Cooling water temperature**		
SERC Generation sub-committee	No	Providing the ambient temperatures at the time data is collected is acceptable. However, there is no simple correction factor that can be provided. Reactive capabilities under different conditions cannot be assumed to

Organization	Yes or No	Question 3 Comment
		be the same.
Response: The GVSDT thanks you for your comment. The GVSDT agrees that the correction factor methodology could be complex, but also points out that simply accounting for the effects of ambient temperature can be sufficient for long-term planning. The standard currently does not require a complex correction factor methodology because the GVSDT did not identify evidence indicating that use of such a methodology would increase reliability. While the GVSDT agrees with your assertion regarding reactive capabilities, the GVSDT does not believe that the standard needs to incorporate these assumptions; instead believing existing practice is sufficient for compliance.		
Westar Energy	No	We believe data should be submitted to the Transmission Planner as written in the draft of the standard.
Response: The GVSDT thanks you for your comment. The TP is the correct entity and is shown in the requirements and Attachment 1.		
Southern Company	No	The verification data is required by R1.3 and R2.3 to be given to the TP, not the TO. If the Q capacity is determined using a staged test, the ambient temperature during the test should be provided. The planning entity can adjust to other temperatures if they desire.
Response: The GVSDT thanks you for your comment. The TP is the correct entity and is shown in the requirements and Attachment 1.		
Tennessee Valley Authority GO	No	Providing the ambient temperatures at the time data is collected is acceptable. However, there is no simple correction factor that can be provided. Reactive capabilities under different conditions cannot be assumed to be the same.
Response: The GVSDT thanks you for your comment. Item 3.4 in Attachment 1 provides guidance with respect to correction factors: **3.4. The ambient conditions at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:** • **Ambient air temperature** • **Relative humidity** • **Cooling water temperature**		
Luminant Power	No	Luminant agrees that ambient test temperature and temperature correction information should be submitted to the appropriate entities. In ERCOT, this would be TOP and BA.
Response: The GVSDT thanks you for your comment.		

Organization	Yes or No	Question 3 Comment
Lakeland Electric	No	It should be acceptable that the Real Power data collected during credible, high-ambient temperature conditions be used to establish Real Power output limits throughout the year, including during lower temperature ambient conditions. By limiting Real Power output to that determined for high-ambient conditions, system reliability will not be compromised during lower ambient temperature conditions/scenarios.
Response: The GVSDT thanks you for your comment. This standard does not address the issue of Real Power output limits to be used in Real-time operations.		
Associated Electric Cooperative, Inc.	No	There is no simple correction factor that can be provided that will allow correction to other ambient temperatures. If necessary, a special request could be made to the GO/GOP for correction to another ambient temperature.
Response: The GVSDT thanks you for your comment. The GVSDT agrees there is not a simple correction factor that can account for all temperature effects; however, the GVSDT also believes it is not necessary to account for all temperature effects in order to maintain reliability.		
New York Independent System Operator	No	Temperature correction shall be performed as required by the Transmission Operator. The NYISO requires ambient temperature data only for Real Power Tests for combined cycle, combustion, and turbine units.
Response: The GVSDT thanks you for your comment. This is a long-term planning standard, and the data verified under MOD-025 is to be used in planning studies. The SDT modified the standard (Attachment 1, Step 3.4) to assign responsibility for making the ambient condition (including ambient temperature) adjustments to the Generator Owner rather than the Transmission Owner.		
Exelon	No	The Standard needs to address correction factors for "ambient conditions" instead of "air temperature." Specifically, large generating units are typically water cooled and therefore the correction factor should be revised as such. In addition, as stated in the response to question 2 above, the Transmission Planner should be the appropriate entity instead of the Transmission Owner.
Response: The GVSDT thanks you for your comment. The SDT modified the standard (Attachment 1, Step 3.4) to change "ambient temperature" to "ambient conditions" and to assign responsibility for making the ambient condition adjustments to the Generator Owner rather than the Transmission Owner. Item 3.4 in Attachment 1 provides guidance with respect to correction factors: **3.4. The ambient conditions at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:** **• Ambient air temperature**		

Organization	Yes or No	Question 3 Comment
• **Relative humidity** • **Cooling water temperature**		
Tacoma Power	No	Tacoma Power is not aware of any industry accepted standard air ambient real power correction factor for hydro units.
Response: The GVSDT thanks you for your comment. Correction factor consideration does not apply for units that are not affected by ambient temperature effects. The GVSDT will revise standard language to clarify this point.		
Georgia Transmission Corporation	No	The ambient temperature and other factors that influence the output should be included. The GO should provide temperature dependent and other data tables/graphs to the TP. Again, the comment form and attachment seem to conflict with R1 and R2 to provide data to the TP not the TO.
Response: The GVSDT thanks you for your comment. The intent of the standard is for the GO to create a correction factor from the data normally used for such purpose. The SDT modified the standard (Attachment 1, Step 3.4) to change "ambient temperature" to "ambient conditions" and to assign responsibility for making the ambient condition adjustments to the Generator Owner rather than the Transmission Owner.		
Austin Energy	No	Ambient temperature will have a less direct effect on water cooled generators with cooling water sources not directly affected by ambient temperature.
Response: The GVSDT thanks you for your comment. Item 3.4 in Attachment 1 provides guidance with respect to correction factors (note these have been revised so that the phrase, "ambient temperature" was replaced with the broader phrase, "ambient conditions"): **3.4. The ambient conditions at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:** • **Ambient air temperature** • **Relative humidity** • **Cooling water temperature**		
BC Hydro	No	Generating facilities are already designed and ratings determined based on maximum expected ambient temperatures. Besides, equipment cooling may not be directly dependent on ambient temperature. Providing the details to other entities would be of no practical value. GOs have to meet declared capabilities as registered or derate their facilities if needed.

Organization	Yes or No	Question 3 Comment
Response: The GVSDT thanks you for your comment. Temperature correction is more important for some units, such as gas turbines. The GO may omit the correction factor if unit Real Power output is not dependent, or is minimally dependent on, temperature. If the TP does not require temperature correction, then uncorrected data is used.		
Constellation Power Generation	No	Constellation Power Generation (CPG) agrees with this approach.
Response: The GVSDT thanks you for your comment. Please see the proposed revisions which identify a broader scope of ambient conditions and assign responsibility for making adjustments to the Generator Owner rather than the Transmission Owner.		
Indiana Municipal Power Agency	No	The owner or operator of the generating unit should do the temperature correction to a specified temperature as directed. The owner will possess the curves and be better acquainted with the unit's limitation and temperature correction.
Response: The GVSDT thanks you for your comment. The GVSDT believes that the Transmission Planner has unilateral authority for determining the correction temperature used, given the Transmission Planner selects the temperature value used for planning studies. The Generator Owner provides the correction factor so the TP can simply perform the work without having to track and verify the communication exchange that would otherwise have to occur with the GO. The SDT modified the standard (Attachment 1, Step 3.4) to change "ambient temperature" to "ambient conditions" and to assign responsibility for making the ambient condition adjustments to the Generator Owner rather than the Transmission Owner.		
Chelan County PUD	No	Should only be required if it impacts the data or test performed. For most generation it would not.
Response: The GVSDT thanks you for your comment. The TP has discretion to perform or not perform temperature correction.		
ISO New England	No	We maintain that temperature correction should be performed as required by the Transmission Operator. The standard must ensure that accurate data for gas turbine and combined cycle generators is obtained which can be adjusted to reflect the ambient temperature presumed in Planning Assessments.
Response: The GVSDT thanks you for your comment. The SDT modified the standard (Attachment 1, Step 3.4) to change "ambient temperature" to "ambient conditions" and to assign responsibility for making the ambient condition adjustments to the Generator Owner rather than the Transmission Owner. The data collected through this standard is intended for use in long-term planning studies.		
Duke Energy	No	System models are used for reliability purposes beyond planning purposes, which are at best, an educated guess at what the system will look like out in the future. The real time and day ahead models are most significant for assuring reliable system operation. It would seem that if the TP needs model data different than the Transmission Operations needs, the 1st step is for them to define a technical basis for that data.

Organization	Yes or No	Question 3 Comment
		Once that is done, then the GO/GOPs can develop numbers that match those conditions. Pmax will vary on ambient temp for some types of generation, lake temps for other types and hydo conditions for those units. Without a defintion of the data based on the studies to be performed, all the GO can do is guess. If the Q capacity is determined using a staged test, the ambient temperature during the test should be provided. The planning entity can adjust to other temperatures if they desire.
Response: The GVSDT thanks you for your comment. The GVSDT believes that the standard satisfies most of your recommendations. The TP has discretion whether or not to use the correction factor provided, so the GO does not need to know the Transmission Planners intention. Keep in mind this standard is a planning standard, not a Real-time operations standard.		
Indeck Energy Services	No	No temperature adjustment can be done reliably with real and reactive power. Real Power may be adjusted, but not with reactive. Generator can make the adjustment if there is a nationwide standard. If not, then regional standards will be required to specify the values.
Response: The GVSDT thanks you for your comment. The GVSDT agrees the temperature correction factor provided is only used for adjusting Real Power values. Item 3.4 in Attachment 1 provides guidance with respect to correction factors: **3.4. The ambient conditions at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:** **• Ambient air temperature** **• Relative humidity** **• Cooling water temperature**		
Gainesville Regional Utilities	No	
Xcel Energy	No	
American Wind Energy Association	No	
Wisconsin Electric	No	
Tri-State Generation and Transmission, In.	No	

Organization	Yes or No	Question 3 Comment
Arizona Public Service Company	No	
Salt River Project	No	
PacifiCorp	No	
Northeast Power Coordinating Council	Yes	Real and reactive power output is affected by the thermal conditions in effect a t the time of testing and dispatch. The output of a generator, and therefore the model of its output, can be more or less temperature dependent, e.g., a combustion turbine with versus the same combustion turbine without inlet chillers. Attachment 1 specifies that the temperature only be recorded at the end of the verification period. Temperatures can vary significantly over the course of the verification period, and at a minimum the ambient temperatures at the beginning and end of a verification period should be recorded. It would also be meaningful and helpful to record ambient temperatures at intermediate points during a verification period. The Real Power data submitted should not be adjusted to a temperature other than ambient. When collecting real time data, it should be "what you see is what you get"; adjustments should not be accepted.
Response: The GVSDT thanks you for your comment. The GVSDT does not believe there is any difference between historical data and staged test data with regards to this issue. Either set of data should be correctable to a different ambient temperature basis than the ambient temperature value existing at time of recording. Also keep in mind that the Transmission Planner is the entity that decides if data is temperature corrected to a different basis when performing studies. The GO only provides collected data and a temperature correction factor to the Transmission Planner.		
Imperial Irrigation District (IID)	Yes	THE REAL POWER DATA OBTAINED FROM GENERATORS IS BASED ON AMBIENT TEMPERATURE AND ADDITIONAL ENVIRONMENTAL AND SYSTEMATIC CONDITIONS. BECAUSE OF THIS REASON, OBTAINING A CORRECTION FACTOR CORRESPONDING SOLELY TO THE AMBIENT TEMPERATURE FOR CALCULATION OF THE REAL POWER WILL NOT BE AN EFFECTIVE APPROACH. IN ADDITION, DUE TO SEVERAL PARAMETERS AS A FUNCTION OF THE REAL POWER AND THE TEMPERATURE, CALCULATION OF AN ACCURATE CORRECTON FACTOR WOULD BE SOMEWHAT DIFFICULT AND COSTLY AS IT MAY REQUIRE SEVERAL GENERATOR TESTING.
Response: The GVSDT thanks you for your comment. There are many factors that affect generator Real Power output, and these factors are different for different types of generating units. The reason why the GVSDT incorporated temperature correction consideration into the draft standard is because most Planners specify ambient temperature conditions when performing planning case studies. The GVSDT does not intend for entities to perform multiple tests. Instead, the GO simply provides a temperature correction factor with test data collected. As a matter of practicality, temperature correction factor information should already be captured as part of the internal process used for performing Real Power testing.		

Organization	Yes or No	Question 3 Comment
Pepco Holdings Inc Affiliates	Yes	The ambient temp and correction factor should be provided to the TP with all the data as stated in Question 2.
Response: The GVSDT thanks you for your comment.		
SPP Reliability Standards Development Team	Yes	We feel that the entity should be the Transmission Planner, but there is a need for the Generator Owner to provide an adjustment factor. The standard should address the temperature to bring the data to and then the Generator Owner could provide the factor to adjust the data. The standard also needs to address the fact that the temperature will not be a single set number and will vary depending on the season and geographic location.
Response: The GVSDT thanks you for your comment. The SDT modified the standard (Attachment 1, Step 3.4) to change "ambient temperature" to "ambient conditions" and to assign responsibility for making the ambient condition adjustments to the Generator Owner rather than the Transmission Owner. Item 3.4 in Attachment 1 provides guidance with respect to correction factors: **3.4. The ambient conditions at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:** • **Ambient air temperature** • **Relative humidity** • **Cooling water temperature**		
SERC Planning Standards Subcommittee	Yes	The Transmission Planner should be allowed to require that the Generator Owner provide an adjusted real power value (instead of an adjustment factor) based on different ambient temperature(s).
Response: The GVSDT thanks you for your comment. The SDT modified the standard (Attachment 1, Step 3.4) to change "ambient temperature" to "ambient conditions" and to assign responsibility for making the ambient condition adjustments to the Generator Owner rather than the Transmission Owner. The intent of the temperature correction factor provision is to allow the Transmission Planner make any correction to collected data deemed necessary during engineering analysis. Item 3.4 in Attachment 1 provides guidance with respect to correction factors: **3.4. The ambient conditions at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:** • **Ambient air temperature** • **Relative humidity**		

Organization	Yes or No	Question 3 Comment
• **Cooling water temperature**		
Dominion	Yes	We believe that, if the Resource Planner or Transmission Planner desire use of any correction factor, other than ambient, they be allowed to request the GO or TO adjust for that (those) correction factor(s) but that compliance with this standard be based solely upon the requirements contained within. If a RE desires to impose additional correction factor(s), it should file for a regional variance to this standard.
Response: The GVSDT thanks you for your comment. The GVSDT has revised the standard to capture additional ambient condition parameters which could be used for correction in addition to ambient air temperature and to change the responsibility for making adjustments from the Transmission Owner to the Generator Owner. Item 3.4 in Attachment 1 provides guidance with respect to correction factors: **3.4. The ambient conditions at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:** • **Ambient air temperature** • **Relative humidity** • **Cooling water temperature**		
Public Service Enterprise Group	Yes	We believe that the Real Power data submitted should be corrected to a temperature specified by the entity that requires the verification of Real Power capability. That entity is probably the Resource Planner or the Planning Coordinator- see the Functional Model, version 5 posted at http://www.nerc.com/files/Functional_Model_V5_Final_2009Dec1.pdf. For Generation Owners that belong to Regional Transmission organization that has a reserve margin criterion, it is probably registered as a Resource Planner and Planning Coordinator. For example, PJM, NYISO, and ISO-NE are each registered as a Resource Planner and a Planning Coordinator.
Response: The GVSDT thanks you for your comment. The SDT modified the standard (Attachment 1, Step 3.4) to change "ambient temperature" to "ambient conditions" and to assign responsibility for making the ambient condition adjustments to the Generator Owner rather than the Transmission Owner. As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the operations planning and Real-time operations time horizons. **Per the NERC Reliability Functional Model (V5, Page 25), the Transmission Planner has the following relationships with other entities:** **2. Collects information including:**		

Organization	Yes or No	Question 3 Comment
c. Generator unit performance characteristics and capabilities from Generator Owners. **5. Coordinates the evaluation of BES expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.** **6. Reports on and coordinates its BES expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers.**		
South Carolina Electric and Gas	Yes	The Transmission Planner should be allowed to require that the Generator Owner provide an adjusted real power value (instead of an adjustment factor) based on different ambient temperature(s).
Response: The GVSDT thanks you for your comment. The GVSDT believes that the Transmission Planner has sufficient flexibility to perform engineering analysis if only a correction factor is provided.		
Cowlitz County PUD	Yes	As long as correction factors may be documented from normal run history, this would not be burdensome to produce. As currently written, MOD-0025-2 appears to allow the Generator Owner to make a judgment call on whether ambient air temperature plays a significant role in generation capacity. If this is the case, then the report form should have a specific question: Is ambient air temperature correction factor applicable? _____ If yes, include in remarks below correction factors for different temperatures. Also, water coolant temperature may play a greater role. A quick passing hot or cool day during testing may not have any effect on the water coolant temperature. Where water temperature has a greater impact on capability, seasonal trends may be of greater significance. Finally, there is no criterion stipulated to define when ambient temperature correction factors are significant and should be provided. Cowlitz suggests that ambient temperature should only be considered significant if it affects Real or Reactive Power capability more than 10% between the lowest and highest expected ambient temperature extremes.
Response: The GVSDT thanks you for your comment. The revised standard (see Requirement R1, Part 1.3) allows the Transmission Planner to use discretion when determining if ambient condition correction is necessary for Real Power verification.		
Northeast Utilities	Yes	Real and reactive power output is affected by the thermal conditions in effect a t the time of testing and dispatch. The output of a generator, and therefore the model of its output, can be more or less temperature dependent, e.g., a combustion turbine with versus the same combustion turbine without inlet chillers. Attachment 1 specifies that the temperature only be recorded at the end of the verification period. Temperatures can vary significantly over the course of the verification period, and at a minimum the ambient

Organization	Yes or No	Question 3 Comment
		temperatures at the beginning and end of a verification period should be recorded. It would also be meaningful and helpful to record ambient temperatures at intermediate points during a verification period. The Real Power data submitted should not be adjusted to a temperature other than ambient. When collecting real time data, it should be "what you see is what you get"; adjustments should not be accepted.
Response: The GVSDT thanks you for your comment. The data is not required to be adjusted. The TP is not required to use the correction factor provided.		
Consolidated Edison Co. of NY, Inc.	Yes	Real and reactive power output is affected by the thermal conditions in effect a t the time of testing and dispatch. The output of a generator, and therefore the model of its output, can be more or less temperature dependent, e.g., a combustion turbine with versus the same combustion turbine without inlet chillers. Attachment 1 specifies that the temperature only be recorded at the end of the verification period. Temperatures can vary significantly over the course of the verification period, and at a minimum the ambient temperatures at the beginning and end of a verification period should be recorded. It would also be meaningful and helpful to record ambient temperatures at intermediate points during a verification period. The Real Power data submitted should not be adjusted to a temperature other than ambient. When collecting real time data, it should be "what you see is what you get"; adjustments should not be accepted.
Response: The GVSDT thanks you for your comment. The data is not required to be adjusted. The TP is not required to use the correction factor provided.		
American Electric Power	Yes	Again, we believe the question should be associated with the providing of ambient temperature and correction factor information to the Transmission Planner and the Resource Planner rather than the Transmission Owner. We believe the Resource Planner should provide the ambient temperature value, while the Generator Owner should provide the correction.
Response: The GVSDT thanks you for your comment. As noted in the GVSDT responses to Question Number 2, the TP is the correct entity. As revised, the standard requires the GO to supply a correction factor that the TP may use to extrapolate data to the desired temperature required for engineering analysis. As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the operations planning and Real-time operations time horizons. **Per the NERC Reliability Functional Model (V5, Page 25), the Transmission Planner has the following relationships with other entities:** **2. Collects information including:** **c. Generator unit performance characteristics and capabilities from Generator Owners.**		

Organization	Yes or No	Question 3 Comment
5. Coordinates the evaluation of BES expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners. **6. Reports on and coordinates its BES expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers.**		
Ingleside Cogeneration LP	Yes	As with question #2, we believe the appropriate recipient of generator verification data is the Transmission Planner, not the Transmission Owner. Secondly, the Generator Owner providing the validation data must also be responsible for any corrections based on ambient temperature - as there may complexities beyond temperature correction factors. In these cases, if the TP performs the calculation, they may otherwise assume more capacity is available in their contingency assessments. The GO should have the option to provide the actual validation results to the TP with a temperature correction factor, but ultimately that decision rests with them. Third, the Transmission Planner must provide the required operating temperature range necessary for their system models. This will assure consistency among generators operating within their planning jurisdiction. If there are any discrepancies between the GO's and TP's expected range of operation, they can work that out through an iterative resolution process - similar to the structure suggested in MOD-026-1 and MOD-027-1.
Response: The GVSDT thanks you for your comment. As revised, the standard requires the GO to supply a correction factor. The GVSDT believes that simply having the GO supply a correction factor for TP discretional use will result in accurate data for planning purposes.		
Manitoba Hydro	Yes	The standard should allow the provision of ambient temperature during the verification be provided to the Transmission Owner as well as a correction factor to allow the Transmission Owner to adjust the Real Power data to a different ambient temperature if needed OR Real Power data submitted be temperature adjusted to some other than ambient temperature as requested by the TO.
Response: The GVSDT thanks you for your comment. The SDT modified the standard (Attachment 1, Step 3.4) to change "ambient temperature" to "ambient conditions" and to assign responsibility for making the ambient condition adjustments to the Generator Owner rather than the Transmission Owner. **Item 3.4 in Attachment 1 provides guidance with respect to correction factors:** **3.4. The ambient conditions at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:**		

Organization	Yes or No	Question 3 Comment
• **Ambient air temperature** • **Relative humidity** • **Cooling water temperature**		
Lincoln Electric System	Yes	The Real Power Data should be adjusted based on temperature to indicate what the output for the generating unit would be for peak summer conditions for a summer peaking utility and peak winter conditions for a winter peaking utility. Humidity is also factor that affects the output of units with evaporative cooling as well as the performance of cooling towers. Previously as part of the Mid-continent Area Power Pool our utility was required to submit monthly capacity accreditation of the generating units that was adjusted based on the ten-year average of the high temperature for the peak load day of the month. For the summer months this provided a fairly accurate estimate of the actual generating capabilities of the unit in the summer months. In the winter using the high temperature for the peak day was not quite as accurate, since the peak on the winter day does not usually coincide with the peak temperature for the day, but the ambient high temperature on these days is usually quite low. Even in the shorter months the output data may be beneficial to the Transmission Planner when large units in a region are out for maintenance. It is questionable as to how easy it would be for the Transmission Owner to apply the correction factors to other ambient temperatures if they are only given the temperature at the time of verification test. For gas turbine units without some form of inlet cooling the output may vary by as much as 30 percent from summer to winter ambient conditions. This is a significant amount of generating capacity.
Response: The GVSDT thanks you for your comment. The SDT modified the standard (Attachment 1, Step 3.4) to change "ambient temperature" to "ambient conditions" and to assign responsibility for making the ambient condition adjustments to the Generator Owner rather than the Transmission Owner. **The GVSDT believes that the Transmission Planner has unilateral authority for determining the correction temperature used given the Transmission Planner selects the temperature value used for planning studies. The Generator Owner provides the correction factor so the TP can simply perform the work without having to track and verify the communication exchange that would otherwise have to occur with the GO.**		
CPS Energy	Yes	Generator owner should perform the correction and determine the temperature value.
Response: The GVSDT thanks you for your comment. The SDT modified the standard (Attachment 1, Step 3.4) to change responsibility for making the ambient condition adjustments to the Generator Owner rather than the Transmission Owner. **The GVSDT believes that the Transmission Planner has unilateral authority for determining the correction temperature used given the Transmission Planner selects the temperature value used for planning studies. The Generator Owner provides the correction factor so the TP can simply perform**		

Organization	Yes or No	Question 3 Comment
the work without having to track and verify the communication exchange that would otherwise have to occur with the GO.		
Ameren	Yes	The ambient temperature at which the testing is performed would be an important data item. Because of greater familiarity with the equipment and its capabilities, any temperature adjustment to arrive at a different specified real power value should be performed by the Generator Owner. The Transmission Owner/Transmission Planner, who would be performing system modeling and study work, would be the entity most appropriate to specify temperature values for which temperature adjustment factors would be determined. Capabilities at different ambient temperatures need to be provided to meet the modeling requirements of the MMWG, and that the GO and TO should agree on what ambient temperatures to assume for the temperature adjustment.
Response: The GVSDT thanks you for your comment. The SDT modified the standard (Attachment 1, Step 3.4) to change responsibility for making the ambient condition adjustments to the Generator Owner rather than the Transmission Owner. **The GVSDT agrees that the TP is the appropriate entity to determine the temperature correction value used for planning studies. The GVSDT believes that the TP can perform any correction that is needed with the correction factor provided by the GO.**		
Oncor Electric Delivery Company LLC	Yes	Oncor believes that this information should be submitted to the Planning Authority in the ERCOT Region and that they (the Planning Authority) should coordinate with the Generator Owner in the development of any correction factor and the appropriate temperature value that should be used.
Response: The GVSDT thanks you for your comment. The SDT modified the standard (Attachment 1, Step 3.4) to change responsibility for making the ambient condition adjustments to the Generator Owner rather than the Transmission Owner.		
Wisconsin Public Service Corp	Yes	
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
APS		being intentionally left blank (no answer to be provided)

4. The SDT believes that verification should be performed on units that are connected down to 100 kV. The SDT has also provided how verification should be handled in plants/Facilities that are greater than 75 MVA in aggregate gross nameplate rating. The Standard requires a separate verification for every unit greater than 20 MVA gross nameplate rating, this is consistent with the current Compliance Registry. Units 20 MVA and smaller, in a plant/Facility greater than 75 MVA can be verified separately or in aggregate as the Generator Owner chooses. Do you agree with the SDT's decision to have the standard be applicable to the compliance registry? If not, please explain.

Summary Consideration: A majority of stakeholders disagreed with making the standard applicability match the same Facility thresholds as specified in the compliance registry. Several stakeholders suggested that the applicable generator size should be 75 MVA, or determined by the Planning Coordinator for its planning area or Interconnection (as specified in other proposed standards). Several stakeholders also suggested that the "sister" unit concept should be allowed for essentially identical units to minimize the number of units tested. Multiple stakeholders suggested referring to the Registry Criteria instead of restating Registry Criteria in the standard in the event criteria changes at a later date. A few stakeholders suggested that generator applicability should be independent of the voltage at the point where the unit is connected. None of the suggestions received include strong justification for having standard applicability deviate from the Compliance Registry, thus the SDT did not change the thresholds in the applicability of the standard.

Several commenters suggested that the applicability of this standard should mimic that of MOD-026 and MOD-027. The GVSDT at one point used direct language referencing the registry criteria, but were advised by NERC to state it as it is currently shown because the compliance registry doesn't address ownership of synchronous condensers. If the registry criteria changes, then changes may be made to the standard. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing. The SDT believes that the applicability is different because MOD-026 and MOD-027 verify dynamic response, while MOD-025 verifies capability. The same basis does not apply.

Blackstart units were removed from the applicability because of redundancies with the requirements of EOP-005-2

R1.4. Identification of each Blackstart Resource and its characteristics including, but not limited to, the following: The name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit.

R6. Each Transmission Operator shall verify, through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed every five years at a minimum. Such analysis, simulations, or testing shall verify: [Violation Risk Factor = Medium] [Time Horizon =Long-term Planning]

R6.1. The capability of Blackstart Resources to meet the Real and Reactive Power requirements of the Cranking Paths and the dynamic capability to supply initial Loads.R9. Each Transmission Operator shall have Blackstart Resource testing requirements to verify that each Blackstart Resource is capable of meeting the requirements of its restoration plan. These Blackstart Resource testing requirements shall include:

[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

R9.1. The frequency of testing such that each Blackstart Resource is tested at least once every three calendar years.

R9.2. A list of required tests including:

R9.2.1. The ability to start the unit when isolated with no support from the BES, or when designed to remain energized without connection to the remainder of the System.

R9.2.2. The ability to energize a bus. If it is not possible to energize a bus during the test, the testing entity must affirm that the unit has the capability to energize a bus, such as verifying that the breaker close coil relay can be energized with the voltage and frequency monitor controls disconnected from the synchronizing circuits.

R9.3. The minimum duration of each of the required tests.

Organization	Yes or No	Question 4 Comment
LG&E and KU Energy	No	Blackstart unit testing is covered in he EOP standards, and should not be included in the MOD standards. Most of these are smaller units that don't have much impact on the BES but are important because they are blackstart-not for the VARs.
Response: The GVSDT thanks you for your comment. VAR testing is important for line charging when considering small black start units.		
Northeast Power Coordinating Council	No	Generally, only units larger 75 MVA are impactful. It is recommended making 75 MVA the reporting floor [regardless of connected voltage]. This is consistent with current draft BES definition being prepared by the BES SDT.
Response: The GVSDT thanks you for your comment. The GVSDT has no basis to exclude any units included in the registration criteria from testing.		

Organization	Yes or No	Question 4 Comment
IRC Standards Review Committee (joint comments)	No	See comment to Q2. The planner should ask for the data that it needs to comply with NERC standards (nothing more and nothing less). There is no need for the requirement to get into the details. The Planning standards will force the Planner to ask for the data that it needs for its models. This approach limits the Planners from asking for data that they do not use in their Planning Models or that is not needed to comply with a NERC standard. This approach also allows the Planner to tailor its requests to the Models and technologies that it has and needs.
Response: The GVSDT thanks you for your comment. Please see the response to Question 2.		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	No	There may be generating units or facilities that are included or excluded as BES elements either by the latest BES definition or the latest BES exception procedure that differ from 4.2.1 and 4.2.2. So we recommend adding anItem 4.2.4 to the Applicability section that states, “Generating Facility, generating unit or synchronous condenser that are designated as a BES Element according to the BES definition or BES exception procedure.”
Response: The GVSDT thanks you for your comment. The GVSDT has no basis to exclude any units included in the registration criteria from testing.		
Cowlitz County PUD	No	The Compliance Registry Criteria was hastily put together without proper reliability justification. The end result has created a registration process that assumes reliability impact where there is none, and allows exemptions where reliability impact does exist. Cowlitz believes in a protective backbone approach to reliability, the bulk power system (BPS) as a whole need not be completely protected in order to assure its reliability. There exists a core “backbone” subset from the BPS which must be protected; this is known as the Bulk Electric System (BES) and is currently undergoing revision in Project 2010-17. Once this project is complete, it may be necessary to revise the Compliance Registry Criteria to clearly identify entities as users of the BES who must participate in BES protective standard compliance activities. In other words, the Compliance Registry objective should be to identify all entities who must participate in the protection of the BES to assure reliability of the BPS, not identify elements of the BES. Cowlitz is not convinced that the Standard be applicable to the compliance registry of Generator Owners. For example, an entity owning a single small 500 KVA generation plant currently is exempt from registration; however it may own a transmission protection system protecting a BES element from a fault originating on the high side of the step up transformer. Therefore it should register as it is material to the reliability of the bulk power system. From the extensive reference of 20 MVA and 75 MVA in the Standard from the Compliance Registry Criteria, it appears that the SDT would not see a need for the 500 KVA generation plant to verify its capability. Further, pointing to the Compliance Registry Criteria’s generator MVA name plate ratings is also questionable. Cowlitz can find no reliability justification; it appears to be completely arbitrary. After reviewing the Field Test

Organization	Yes or No	Question 4 Comment
		Results, Cowlitz finds that WECC set the line at 10 MVA and SERC recommended 75 MVA with no substantiating arguments. Also noted in the Field Test Results was a problem in getting the dynamic models to return data results that agreed with actual events. With the Field Test Results dated in 2007, Cowlitz is unsure on the current accuracy of dynamic model predictions. However, if models are currently accurate it should be a simple process to verify the size of generation that can be ignored. Looking over the data requirements of MOD-25, Cowlitz can see that there will be considerable consultant cost - $25,000 - to comply. Using the Compliance Registry Criteria for applicability is not acceptable. Unwarranted compliance efforts will reduce overall reliability results. Cowlitz recommends the SDT consult with Planning Coordinators (Planning Authorities) and Transmission Planners on the current status of modeling accuracy and request documentation for generation that can be ignored. Also, it may be permissible for smaller generation to simply report seasonal historical Real and Reactive Power output.
Response: The GVSDT thanks you for your comment. MOD-025 calls for verification of static points that the unit is capable of reaching. Transmission or unit equipment limitations may prevent a unit from reaching its design basis. As generating equipment ages, its operating characteristics change. Over time, unit performance degrades unless upgrades to the unit are made. In order to ensure that planning models have accurate, dependable data, verifications need to be performed. The GVSDT has no basis to exclude any units included in the registration criteria from testing. The GVSDT also believes that a five-year testing interval would not be a burden.		
SERC Planning Standards Subcommittee	No	The use of sisters units should be allowed by the standard. Also, verification should apply on the 75 MVA units, and above. Units smaller than this have very little impact on grid reliability. However, the standard should apply to designated blackstart units included in a system restoration plan, regardless of size.
Response: The GVSDT thanks you for your comment. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units, including sister units. The GVSDT has no basis to exclude any units included in the registration criteria from testing.		
Ameren	No	The allowance for exemption of sister units should be permitted. Only one verification for sister units should be required. Testing for units less than 75 MVA should not be required, as these have little impact on grid reliability.
Response: The GVSDT thanks you for your comment. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units, including sister units. The GVSDT has no basis to exclude any units included in the registration criteria from testing.		
Indeck Energy Services	No	Some standards need to apply to all registered generators. These do not. The minimum unit size should be at the NERC Reportable Disturbance level for the control area. Variations in any other sized unit need not

Organization	Yes or No	Question 4 Comment
		even be reported. This isn't about treating all generators fairly, it is about what is affecting BPS reliability.
Response: The GVSDT thanks you for your comment. The GVSDT has no basis to exclude any units included in the registration criteria from testing.		
Chelan County PUD	No	For multi-unit hydro and wind plants this can become a large effort. A "type" test where one of an identical family of units is verified is more practical and should provide sufficient data.
Response: The GVSDT thanks you for your comment. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units, including sister units.		
Santee Cooper	No	Recommend changing Section 4.2 Facilities to match Section 4.2 Facilities as it is written in MOD-026-1 and MOD-027-1 below: 4.2. Facilities For the purpose of this standard, the following Facilities are considered, “applicable units.” Units or plants with an average capacity2factor greater than 5% over the last three calendar years that meet the following: 4.2.1 Generating units connected to the Eastern or Quebec Interconnections with the following characteristics: o Each generating unit with a gross nameplate rating greater than 100 MVA, connected at the point of interconnection3at greater than 100 kV. o For each plant with a gross aggregate nameplate rating greater than 100 MVA, connected at the same point of interconnection at greater than 100 kV: o Each unit with a gross nameplate rating greater than 20 MVA; and o The remainder of the plant as an aggregate. There should also be some allowance for Units which are nearly identical and therefore model the same.
Response: The GVSDT thanks you for your comment. The GVSDT at one point used direct language referencing the registry criteria, but were advised by NERC to state it as it is currently shown because the compliance registry doesn’t address ownership of synchronous condensers. If the registry criteria changes, then changes may be made to the standard. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing. The SDT believes that the applicability is different because MOD-026 and MOD-027 verify dynamic response while MOD-025 verifies capability. The same basis does not apply.		
PPL Generation	No	The applicability of this standard should include, "and having a capacity factor for the past three years averaging over 10%." As presently written this standard would require VAR testing of a small, emergency genset if located in a baseload facility interconnected greater than 100 kV.

Organization	Yes or No	Question 4 Comment
Response: The GVSDT thanks you for your comment. The GVSDT believes that a five-year testing frequency is reasonable for any unit. The GVSDT does not believe that emergency generators are connected at 100 kV and would therefore not be included. The GVSDT believes that when the capacity is needed the most and therefore most critical to reliability is the time when these units would be running, and, therefore, should be verified.		
SERC Dynamics Review Sub-committee	No	The use of sister units should be allowed by the standard. Also, verification should apply on the 75 MVA units, and above. Units smaller than this have very little impact on grid reliability.
Response: The GVSDT thanks you for your comment. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units, including sister units. The GVSDT has no basis to exclude any units included in the registration criteria from testing.		
NERC Staff	No	While we agree that all units connected at voltage <100 kV need not be tested and modeled, any units >20 MVA and plants/facilities >75 MVA should be tested and modeled accurately regardless of interconnection voltage. The reliability impact of generating units is more directly related to unit capability than interconnection voltage.
Response: The GVSDT thanks you for your comment. The GVSDT has no basis to exclude any units included in the registration criteria from testing.		
SERC Generation sub-committee	No	We believe that Section 4 Applicability (4.2.1 and 4.2.2) for this standard should be revised to match the Section 4 Applicability for MOD-026-1 and MOD-027-1. NERC is focusing on standard requirements that have significant impacts on system reliability. Including smaller units without demonstrating their criticality to the system appears inconsistent with this philosophy. Verification for smaller units should only be required if technically justified by the Planning Coordinator as specified in 4.2.4 of MOD-026-1. The use of "sister" (essentially identical) units should be allowed by the standard (as is allowed in SERC's current MOD-025 procedure). Independent verification of essentially identical units should not be required. Blackstart units (4.2.3 of Section 4 above) should not be covered under the MOD standards. They are covered under the EOP standards (EOP-005-2).
Response: The GVSDT thanks you for your comment. The GVSDT at one point used direct language referencing the registry criteria, but were advised by NERC to state it as it is currently shown because the compliance registry doesn't address ownership of synchronous condensers. If the registry criteria changes, then changes may be made to the standard. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing. The SDT believes that the applicability is different because MOD-026 and MOD-027 verify dynamic response while MOD-025 verifies capability. The same basis does not apply.		

Organization	Yes or No	Question 4 Comment
Black start units were removed from applicability because they are addressed in EOP-005, as you suggest.		
Arizona Public Service Company	No	Verification on units less than 50 MVA is an unnecessary burden and does not add significantly to reliability of the BES. Many of these units are not even modeled because of the availability of other units for a given schedule.
Response: The GVSDT thanks you for your comment. The GVSDT has no basis to exclude any units included in the registration criteria from testing.		
Southern Company	No	We believe that Section 4 Applicability for this standard should be revised to match the Section 4 Applicability for MOD-026-1 and MOD-027-1 with respect to inidividual unit size of 100 MVA for the Eastern Interconnection. However, for plants with a gross aggregate nameplate rating â‰¥ 100, we question the need to perform verification for individual units as small as 20 MVA. A 20MVA machine today can not impact the system like it could have 20 years ago. A technical basis for verification of units as small as 20MVA needs to be provided. NERC is focusing on standard requirements that have significant impacts on system reliability, and including smaller units without demonstrating their criticality to the system seems to be inconsistent with this philosophy. Verification for smaller units should only be required if technically justified by the Planning Coordinator as specified in 4.2.4 of MOD-026-1.
Response: The GVSDT thanks you for your comment. The GVSDT at one point used direct language referencing the registry criteria, but were advised by NERC to state it as it is currently shown because the compliance registry doesn't address ownership of synchronous condensers. If the registry criteria changes, then changes may be made to the standard. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing. The SDT believes that the applicability is different because MOD-026 and MOD-027 verify dynamic response while MOD-025 verifies capability. The same basis does not apply.		
Tennessee Valley Authority GO	No	We believe that Section 4 Applicability (4.2.1 and 4.2.2) for this standard should be revised to match the Section 4 Applicability for MOD-026-1 and MOD-027-1. NERC is focusing on standard requirements that have significant impacts on system reliability. Including smaller units without demonstrating their criticality to the system appears inconsistent with this philosophy. Verification for smaller units should only be required if technically justified by the Planning Coordinator as specified in 4.2.4 of MOD-026-1. The use of "sister" (essentially identical) units should be allowed by the standard (as is allowed in SERC's current MOD-025 procedure). Independent verification of essentialy identical units should not be required.

Organization	Yes or No	Question 4 Comment
Response: The GVSDT thanks you for your comment. The GVSDT at one point used direct language referencing the registry criteria but were advised by NERC to state it as it is currently shown because the compliance registry doesn't address ownership of synchronous condensers. If the registry criteria changes, then changes may be made to the standard. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units, including sister units. The SDT believes that the applicability is different because MOD-026 and MOD-027 verify dynamic response, while MOD-025 verifies capability. The same basis does not apply.		
South Carolina Electric and Gas	No	The verification of sisters units on an alternating basis should be allowed by the standard.
Response: The GVSDT thanks you for your comment. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units, including sister units.		
Associated Electric Cooperative, Inc.	No	The use of "sister" (essentially identical) units should be allowed by the standard (as is allowed in SERCs current MOD-025 regional criteria). Independent verification of essentially identical units should not be required.
Response: The GVSDT thanks you for your comment. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units, including sister units.		
Tacoma Power	No	1) Gross unit nameplate is not an industry defined term. The size of unit required for verification for hydro units should be the FERC defined licensed hydro unit nameplate rating. 2) Aggregate gross nameplate plant/facility capacity for hydro units is not a defined term and may not be the combined unit capacities. It is common for hydro facilities with multiple units have increased head losses or other restrictions that restrict or limit plant capacity below the aggregate gross nameplate capacity. For determining gross aggregate hydro plants and units for verification it should be the FERC defined plant licensed capacity.
Response: The GVSDT thanks you for your comment. The terms, "gross unit nameplate" and "aggregate gross nameplate" are not used in the standard. The GVSDT has no basis to exclude any units included in the registration criteria from testing.		
BC Hydro	No	In principle, using compliance registry as a sole criteria for applicability of Reliability Standards removes technical evaluation and justification from the process. The value that technical experts participating in SDTs may add becomes limited, which ultimately does not benefit the industry.
Response: The GVSDT thanks you for your comment. The GVSDT agrees but has no basis to exclude any units included in the registration criteria		

Organization	Yes or No	Question 4 Comment
from testing.		
Northeast Utilities	No	Generally, only units larger 75 MVA are impactful. It is recommended making 75 MVA the reporting floor [regardless of connected voltage]. This is consistent with current draft BES definition being prepared by the BES SDT.
Response: The GVSDT thanks you for your comment. The GVSDT has no basis to exclude any units included in the registration criteria from testing. This standard may have to be revised if the registry criteria changes.		
Constellation Power Generation	No	Although CPG agrees with the approach of applying this standard to all generation facilities in the compliance registry, mimicking it in the standard is redundant and problematic. Should the compliance registry change, then this standard may include facilities not registered with NERC. Conversely, this standard could potentially exclude facilities in the registry should the compliance registry change.
Response: The GVSDT thanks you for your comment. The GVSDT at one point used direct language referencing the registry criteria but were advised by NERC to state it as it is currently shown because the compliance registry doesn't address ownership of synchronous condensers. This standard may have to be revised if the registry criteria changes.		
Consolidated Edison Co. of NY, Inc.	No	Generally, only units larger 75 MVA are impactful. It is recommended making 75 MVA the reporting floor [regardless of connected voltage]. This is consistent with current draft BES definition being prepared by BES SDT.
Response: The GVSDT thanks you for your comment. The GVSDT has no basis to exclude any units included in the registration criteria from testing. This standard may have to be revised if the registry criteria changes.		
Duke Energy	No	Obviously, all units which are critical to reliability should be included, but what is critical is dependent upon system configurations. The continent wide standard should specify the largest size units critical in an interconnection and then regional standards might tighten the number based on that region's need. The SERC region currently requires real & reactive verification only for units > 75 MVA (RFC uses 85 MVA). The use of "sister" (essentially identical) units should be allowed by the standard (as is allowed in SERC's current MOD-025 procedure). Independent verification of essentialy identical units should not be required. Blackstart units (4.2.3 of Section 4 above) should not be covered under the MOD standards. They are covered under the EOP standards (EOP-005-2).

Organization	Yes or No	Question 4 Comment
Response: The GVSDT thanks you for your comment. Any testing performed for Blackstart Resources under the EOP standards may be used to show compliance with the MOD-025 standard for similar requirements. Additional or separate testing is not required. The GVSDT also believes that a five-year testing frequency is reasonable for any unit. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units, including sister units.		
Independent Electricity System Operator	No	The Applicability section is not clear enough to expect consistent application. When the facility that makes the connection at 100 kV or above is not owned by the Generator Owner (e.g. a Distribution Provider might own this facility) the present expression of the standard will lead to inconsistencies. Facilities with identical electrical characteristics may or may not be subject to this standard only because of the structure of the ownership of assets. To address this, we propose revising section 4.2 by removing the condition for interconnection at 100 kV and above and aligning with the standard's purpose:4.2.1 Individual generating unit or synchronous condenser greater than 20 MVA (gross nameplate rating) considered in BES reliability assessments.. 4.2.2 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) considered in BES reliability assessments.4.2.3 Blackstart units, regardless of size that are included in a Transmission Operator's restoration plan.
Response: The GVSDT thanks you for your comment. The GVSDT has revised the applicability to be consistent with NERC Compliance Registry Criteria and other standards being developed under this project: **For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following:** **4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) in a directly connected to the bulk power system.** **4.2.2 Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the bulk power system.** **4.2.3 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the bulk power system.**		
Indiana Municipal Power Agency	Yes	IMPA supports the SDT's decision to have the standard be applicable to the compliance registry.
Response: The GVSDT thanks you for your comment.		
Idaho Power-Power Production	Yes	Consistency with the compliance registry and the BES definition is important.

Organization	Yes or No	Question 4 Comment
Response: The GVSDT thanks you for your comment.		
FirstEnergy	Yes	We agree that this standard should be consistent with the NERC Compliance Registry.
Response: The GVSDT thanks you for your comment.		
Westar Energy	Yes	We propose that language be added to reference the Compliance Registry to ensure that as the Registry changes the appropriate applicability is followed.
Response: The GVSDT thanks you for your comment. The GVSDT at one point used direct language referencing the registry criteria, but were directed by NERC to state it as it is currently shown. If the registry criteria changes then changes may be made to the standard.		
SPP Reliability Standards Development Team	Yes	If the intent is that the team wants to follow the Compliance Registry then we would ask that there be direct language reference to the Registry. If this isn't done and the Registry changes as worded now the standard would be static to the numbers given. This team needs to get plugged into the BES DEF standard drafting team as there are discussions being held currently that could change the Registry criteria.
Response: The GVSDT thanks you for your comment. The GVSDT at one point used direct language referencing the registry criteria but were advised by NERC to state it as it is currently shown because the compliance registry doesn't address ownership of synchronous condensers. If the registry criteria changes, then changes may need to be made to the standard.		
Ingleside Cogeneration LP	Yes	These applicability criteria are consistent within the Regions that Ingleside Cogeneration has familiarity with (TRE, WECC, and SERC).
Response: The GVSDT thanks you for your comment.		
ISO New England	Yes	Yes, however the standard should not rewrite the Compliance Registry as attempted in section 4.2. The registry language of section IIIc.3 and IIIc.4 is more precise and differs from what is proposed in the standard. For instance, the registry's wording on Black Start generators applies to a blackstart unit material to and designated as part of a transmission operator entity's restoration plan. All that is needed is to have the standard applicable to Generator Owners and let the Registry dictate those who must register and comply.
Response: The GVSDT thanks you for your comment. The GVSDT at one point used direct language referencing the registry criteria but were advised by NERC to state it as it is currently shown because the compliance registry doesn't address ownership of synchronous condensers.		

Organization	Yes or No	Question 4 Comment
Manitoba Hydro	Yes	The Applicability of this standard should be to BES Generating Units and Facilities. Section 4.2 should not restate components of the proposed BES definition.
Response: The GVSDT thanks you for your comment. The GVSDT at one point used direct language referencing the registry criteria but were advised by NERC to state it as it is currently shown because the compliance registry doesn't address ownership of synchronous condensers.		
Imperial Irrigation District (IID)	Yes	
Pepco Holdings Inc Affiliates	Yes	
Dominion	Yes	
Public Service Enterprise Group	Yes	
ACES Power Members	Yes	
Luminant Power	Yes	
Salt River Project	Yes	
PacifiCorp	Yes	
Dynegy Inc.	Yes	
New York Independent System Operator	Yes	
Tri-State Generation and Transmission, In.	Yes	
Xcel Energy	Yes	
Lakeland Electric	Yes	

Organization	Yes or No	Question 4 Comment
Exelon	Yes	
American Wind Energy Association	Yes	
Georgia Transmission Corporation	Yes	
Austin Energy	Yes	
Wisconsin Electric	Yes	
American Electric Power	Yes	
Wisconsin Public Service Corp	Yes	
CPS Energy	Yes	
Gainesville Regional Utilities	Yes	
Oncor Electric Delivery Company LLC	Yes	
APS		being intentionally left blank (no answer to be provided)
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Response: The GVSDT thanks you for your comment.		

5. The draft standard requires that the Reactive Power capability be verified at four points: Over-excited (lagging) and under-excited (leading) Reactive capability at (1) the rated Real Power capability and (2) expected minimum Real Power output. The SDT believes that this is consistent with the FERC directive in Order 693 at P1321, "Therefore, we adjust the proposal in the NOPR and direct the ERO to modify MOD-025-1 to require verification of Reactive Power capability at multiple points over a unit's operating range." Do you agree that the four points proposed by the SDT is adequate to provide a straight line approximation to a unit's Reactive Power capability over its actual operating range? If not, please explain.

Summary Consideration: A majority of stakeholders agreed that the four points proposed by the SDT are adequate to provide a straight-line approximation to a unit's Reactive Power capability over its actual operating range. Some stakeholders suggested testing less than four points (i.e. only Pmax, Qmax for nuclear units), while others suggested not testing at all. The SDT agrees that the four points proposed will provide an adequate approximation of the machine's capability and satisfy the directive in Order 693. For units that have environmental or other legally-bound restrictions, the standard does not require violating those restrictions. If a unit has no leading capability, then it should be reported with no leading capability. This statement was added as Note 4 of Attachment 1:

> Note 4: The verification is intended to define the limits of the unit's capabilities. If a unit has no leading capability, then it should be reported with no leading capability, or the minimum lagging capability at which it can operate.

Organization	Yes or No	Question 5 Comment
LG&E and KU Energy		The addition of the lagging and leading at (2); the expected minimum Real Power output are new points to test from the existing version of MOD-025. This will eventually double the testing window (at a minimum)
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve.		
IRC Standards Review Committee (joint comments)	No	See comment to Q2. The planner should ask for the data that it needs to comply with NERC standards (nothing more and nothing less). There is no need for the requirement to get into the details. The Planning standards will force the Planner to ask for the data that it needs for its models. This approach limits the Planners from asking for data that they do not use in their Planning Models or that is not needed to comply

Organization	Yes or No	Question 5 Comment
		with a NERC standard. This approach also allows the Planner to tailor its requests to the Models and technologies that it has and needs.
Response: The GVSDT thanks you for your comment. See response to Question 2.		
SPP Reliability Standards Development Team	No	This is a non linear curve. Is the reason for using the 4 point method all that would fit into the model? We also have the concern that isn't addressed here and it is if the unit can't be tested at the time due to system conditions then you must wait until the system is able. We feel that the points should reflect what is usable.
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve. Although the GVSDT does not believe that engineering analysis alone is sufficient, it is envisioned that engineering analysis may be used to supplement operational data or staged testing. The following Note was added to Attachment 1 of the standard: **"While not required by the standard, it is desirable to perform engineering analysis to determine expected unit capabilities under less restrictive system conditions. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of unit capability that the Transmission Planner can use for modeling."**		
Idaho Power-Power Production	No	No, we believe that the four points are not adequate to describe a unit's capability. FAC-008 and FAC-009 require us to have a normal and emergency rating and the WECC validation policy requires the verification of the unit's capability. Is this standard intended to replace those standards/policies? If so it was not clear in the project documentation. If not, we believe this standard to be redundant to our existing policies and procedures here in WECC.
Response: The GVSDT thanks you for your comment. MOD-025-2 is not intended to replace FAC-008 or FAC-009. The FAC standards relate to a Facility ratings methodology while MOD-025 is a verification of actual performance. It is possible that the required performance in this standard may satisfy the WECC validation policy.		
Santee Cooper	No	The current SERC Regional Criteria requires gross and net reactive capability be determined within the power factor range at which the generating equipment is normally expected to operate. We do not believe anything is gained by testing in power factor ranges where the unit is not expected to operate.
Response: The GVSDT thanks you for your comment. The GVSDT disagrees. The full reactive capability range must be known for planning purposes.		
Dominion	No	We believe that, if the Resource Planner or Transmission Planner desire use of any correction factor, other than ambient, they be allowed to request the GO or TO adjust for that (those) correction factor(s) but that

Organization	Yes or No	Question 5 Comment
		compliance with this standard be based solely upon the requirements contained within. If a RE desires to impose additional correction factor(s), it should file for a regional variance to this standard.
Response: The GVSDT thanks you for your comment. As now stated, the revised standard requires that sufficient data be taken to allow correction to conditions other than ambient, if requested. This requirement addresses one of the directives in FERC Order 693.		
FirstEnergy	No	As a TO, we rank the importance to the modeling effort as follows: (1) Pmax, Qmax; (2) Pmin, Qmin; (3)) Pmax, Qmin. We believe that the Pmin, Qmax is of little value to a Planning Engineer.
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve.		
NERC Staff	No	Reactive Power capability is not a linear function of Real Power. The reactive capability curve and minimum excitation limiter settings for each machine should be used to determine the expected gross reactive capability.
Response: The GVSDT thanks you for your comment. The GVSDT concurs that reactive capability is not a linear function of Real Power. However, MOD-025-2 is a performance-based standard which is to verify the Real and Reactive power capabilities of generators.		
Public Service Enterprise Group	No	For clarification, Attachment 1, paragraph 2.2 does not require Reactive Power capability verification for wind and photovoltaic at minimum Real Power output. It also appears that Nuclear Units are also exempt. "Nuclear Units" has the term "Units" capitalized, but it is not in the NERC Glossary and should probably be lower case. We suggest that R2.2 be redrafted as follows: "Verify Reactive Power capability of all generating units other than nuclear, wind and photovoltaic for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they could normally be expected to operate. In addition, nuclear units should be exempted from under-excited Reactive Power verification at maximum Real Power capability because such verification may lead to concerns with unit stability and potential under-voltage conditions on internal nuclear plant safety buses. This would require a change in paragraph 2.1For other units, these points are acceptable.
Response: The GVSDT thanks you for your comment. The GVSDT believes that if a nuclear plant has under-excited capability, it should be tested within the unit's capability and declared safety margins. The standard does not require challenging unit capabilities. The following statement was added to Note 1 of Attachment 1 for clarity, "Auxiliary bus voltage limits should be observed."		
SERC Generation sub-committee	No	Although we agree that four points are sufficient to provide a straight line approximation over a unit's

Organization	Yes or No	Question 5 Comment
		operating range, we don't agree that four points are needed for baseload units. We strongly agree with the Commission's statement that "such a requirement for all generators may not be necessary." First, we believe 2.2, of Attachment 1 to the standard, should exempt all base load units (not just nuclear units) from verification of reactive capability at minimum real power output. There are other units that the industry should be able to exempt based on their normal operating modes. Examples are peaker CTs and units that have restrictions (environmental, run of the river, etc.) preventing operation at minimum load.Finally, for units where verification of multiple points are needed, the analytical approach to verification,discussed in our responses to Questions 10, 11, and 14, serves this purpose very well.This concern is addressed in Paragraph 1321 of the FERC Order which states: "...other than baseload units, most generating units rarely operate at full MW loading. It is unclear what reactive capability is available throughout a unit's real power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit's real power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary." Also, The GS does not believe that verification for leading capability should be required where operational practices preclude operation in a leading mode.
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve. Analytical methods do not provide verification of equipment capability. The standard requires testing at the minimum Load that a unit is normally expected to operate. For units that have environmental or other legally-bound restrictions, the standard does not require violating those restrictions. If a unit has no leading capability, then it should be reported with no leading capability. This statement was added as Note 4 of Attachment 1: **Note 4: The verification is intended to define the limits of the unit's capabilities. If a unit has no leading capability, then it should be reported with no leading capability or the minimum lagging capability at which it can operate.**		
Southern Company	No	We agree that four points are sufficient to provide a straight line approximation over a unit's operating range. However, we strongly agree with the Commission's statement that "such a requirement for all generators may not be necessary." Paragraph 1321 of the FERC Order states, "...other than baseload units, most generating units rarely operate at full MW loading. It is unclear what reactive capability is available throughout a unit's real power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit's real power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary." These statements indicate the Commission is seeking further guidance from the industry. Based on this, we have the following recommendations. First, we believe 2.2 of Attachment 1 to the standard should exempt all base load units, not just nuclear units, from verification of reactive capability throughout the full MW range. There are other units the industry should be able to justify exempting based on their normal operating modes.

Organization	Yes or No	Question 5 Comment
		Examples are peaker CTs and units that have restrictions (environmental, run of the river, etc.) that prevent operation at minimum load. Second, we suggest that an evaluation be made on a small subset of units that could then be used to respond to the question raised by FERC. Our experience indicates that a unit will typically be capable of delivering or absorbing a comparable amount of reactive power to/from the grid at minimum load when compared to full load. The industry as a whole does not need to perform the verification at multiple points on 100% of the units to respond to an open question from FERC. Third, for units where verification of multiple points are needed, the analytical approach to verification we discuss in our responses to Questions 10, 11, and 14 serves this purpose very well.
Response: The GVSDT thanks you for your comment. The drafting team believes that four test points represent the minimum number required to meet the FERC directive of testing multiple points throughout the Load range to approximate the capability curve. Nuclear units are exempted from Reactive Power testing at low Real Power levels to minimize risks associated with changing reactor power levels. These same risks are not present for other base Load units. Analytical methods do not provide verification of equipment capability. The standard requires testing at the minimum Load that a unit is normally expected to operate. For units that have environmental or other restrictions, the standard does not require violating those restrictions.		
Tennessee Valley Authority GO	No	Although we agree that four points are sufficient to provide a straight line approximation over a unit's operating range, we don't agree that four points are needed for baseload units. We strongly agree with the Commission's statement that "such a requirement for all generators may not be necessary."First, we believe 2.2, of Attachment 1 to the standard, should exempt all base load units (not just nuclear units) from verification of reactive capability at minimum real power output. There are other units that the industry should be able to exempt based on their normal operating modes. Examples are peaker CTs and units that have restrictions (environmental, run of the river, etc.) preventing operation at minimum load. Finally, for units where verification of multiple points are needed, the analytical approach to verification, discussed in our responses to Questions 10, 11, and 14, serves this purpose very well. This concern is addressed in Paragraph 1321 of the FERC Order which states:"...other than baseload units, most generating units rarely operate at full MW loading. It is unclear what reactive capability is available throughout a unit's real power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit's real power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary."Also, We do not believe that verification for leading capability should be required where operational practices preclude operation in a leading mode.
Response: The GVSDT thanks you for your comment. The drafting team believes that four test points represent the minimum number required to meet the FERC directive of testing multiple points throughout the Load range to approximate the capability curve. Nuclear units are exempted from Reactive Power testing at low Real Power levels to minimize risks associated with changing reactor power levels. These same risks are not present for		

Organization	Yes or No	Question 5 Comment
other base Load units. Analytical methods do not provide verification of equipment capability. The standard requires testing at the minimum Load that a unit is normally expected to operate. For units that have environmental or other restrictions, the standard does not require violating those restrictions.		
Luminant Power	No	Luminant proposes the following: 1. At High Load - Maximum overexcitation and under-excitation testing shall be conducted at a minimum of 95% of real power output capability and achieve 90% or greater MVAR output based on the reactive capability curve or as limited by system conditions. 2. At Low Load - Maximum overexcitation and under-excitation testing shall be conducted in the output range between minimum stable load and minimum stable load plus 30%, and achieve 90% or greater MVAR output based on the reactive capability curve or as limited by system conditions. 3. Lead and lag tests can conducted independently.
Response: The GVSDT thanks you for your comment. The GVSDT believes that the Loads required for testing are safe and adequately described. Wording has been changed to better define tests derived from historical data in Requirements R1-R3 and Item 2 in Attachment 1. **Lead and lag tests can be conducted independently.**		
PacifiCorp	No	PacifiCorp believes that the four points proposed by the SDT are adequate with respect to thermal and hydro generation units; however, the proposed points do not adequately take operating conditions for wind generation facilities into consideration.
Response: The GVSDT thanks you for your comment. The GVSDT welcomes suggestions relative to testing wind generation facilities.		
Associated Electric Cooperative, Inc.	No	We don't agree that four points are needed for baseload units, since they are rarely expected to operate at or near Pmin. In addition to nuclear units, baseload units should be exempt from reactive capability verification at Pmin.
Response: The GVSDT thanks you for your comment. Nuclear units are exempted from Reactive Power testing at low Real Power levels to minimize risks associated with changing reactor power levels. These same risks are not present for other base Load units. Testing nuclear units at P min is not required by the standard.		
New York Independent System Operator	No	There is no value to performing the lagging testing at minimum real power loading and leading test at maximum power. The testing requirement should be changed to two test points. One test for an hour to

Organization	Yes or No	Question 5 Comment
		verify over-excited (lagging) capability at the real power level specified by the Transmission Operator or the Transmission Planner; a second test to verify under-excited capability (leading) at the real power level specified by the Transmission Operator or the Transmission Planner.
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve.		
Cowlitz County PUD	No	Cowlitz answers "no" in that the question does not address if the data is truly going to be used. The SDT should confer with Transmission Planners requesting specifically how they will implement such data and if it will result in better modeling results. Data collection that will not be used is wasted compliance effort. FERC also seems to be confused as to the purpose of the Standard when it states "[t]he capability of generators to produce reactive power is essential for real-time analysis" rather than system modeling and planning. Based on this, should the reactive capability data also be sent to the Balancing Authority? If the SDT has technical foundation to refute FERC's directive then it should be communicated. The Standard can be written as FERC demands, but with a recommendation that the requirement be removed.
Response: The GVSDT thanks you for your comment. The GVSDT has no technical foundation to refute the FERC directive in Paragraph 1321, which states: **"1321. We disagree with commenters that verifying generator reactive capability is a particularly difficult issue. The capability of generators to produce Reactive Power is essential for Real-time analysis and planning. The Reliability Standard addressing this issue requires a generator to verify Reactive capability only at the unit's full MW Loading. However, other than base Load units, most generating units rarely operate at full MW Loading. It is unclear what Reactive capability is available throughout a unit's Real Power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit's Real Power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary. Therefore, we adjust the proposal in the NOPR and direct the ERO to modify MOD-025-1 to require verification of reactive power capability at multiple points over a unit's operating range."** **Regarding the Balancing Authority: As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the operations planning and Real-time Operations time horizons. Per the NERC Reliability Functional Model (VP, page 25), the Transmission Planner has the following relationships with other entities:** **2. Collects information including:** **c. Generator unit performance characteristics and capabilities from Generator Owners.** **5. Coordinates the evaluation of BES expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource**		

Organization	Yes or No	Question 5 Comment
Planners, and other Transmission Planners. **6. Reports on and coordinates its BES expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers.**		
Exelon	No	Currently Attachment 1 states that nuclear units are excluded from performing Reactive Power verification at minimum Real Power output. This exclusion must be extended to include a statement that nuclear units are not required to perform under-excited (leading) reactive capability verification testing. Nuclear units do not perform under-excited (leading) reactive capability testing due to concerns with unit stability and potential under voltage conditions on internal nuclear plant safety buses that may challenge safe plant operations and could lead to a plant transient or shutdown in accordance with NRC operating license. Suggest the following revision to Attachment 1 as follows:2.2 Verify Reactive Power of all generating units other than wind and photovoltaic for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they could normally be expected to operate. Nuclear Units are not required to perform under-excited (leading) reactive capability verification testing or Reactive Power verification at minimum Real Power output.
Response: The GVSDT thanks you for your comment. If a nuclear plant has under-excited capability, it should be tested within the unit's capability and declared safety margins. The standard does not require challenging unit capabilities. The following statement was added to Note 1 of Attachment 1 for clarity, "Auxiliary bus voltage limits should be observed."		
Georgia Transmission Corporation	No	Reactive capability cannot be determined, generally, without disturbances to the system. Long-term fault recorders could be installed at all generator high-side buses and verification of generation to any eventual disturbances could be used to get a better picture of the plants reactive power capability.
Response: The GVSDT thanks you for your comment. Engineering analysis is allowed and encouraged to supplement testing and gain a better picture of the plant's reactive power capability.		
Great River Energy	No	GRE doesn't agree with doing the under and over-excited limits at min. power levels. Mainly for baseload units, this is not representative of where the units run. Also, this would be costly when you are taking a baseload unit to min. load for the testing. There are also many unit specific conditions that exist that may prevent an unit from running at its true minimum load. If they want it at different points I think they should leave it up to the GO/GOP's to decide at what other load point they want to run the test.
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve. Low Load verification is required at the "minimum Real		

Organization	Yes or No	Question 5 Comment
Power output at which the unit is normally expected to operate."		
BC Hydro	No	Technically, only verification at the maximu rated active power output has practical value since it is the most limiting operating condtion in terms of reactive power capability.Verifying reactive power capability at lower active power outputs is redundant because: 1. The capability will obviously be somewhat higher than at maximum active power output 2. Registration data normally include only Qmax and Qmin, which are determined at unit's rated active power output. 3. Reactive capability does not depend on unit's active power output as much as on other factors, such as system or station service voltagesD-curve is developed based on calculated data. The purpose of this should not be verification of the curve
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve.		
ISO New England	No	Performing testing for lagging capability at minimum real power output especially would require an inordinate amount of planning to ensure that transmission voltage levels in the local area are not exceeded. Testing requirements should be changed to two points, one for an hour to verify over-excited reactive capability at rated Real Power and one at minimum Real Power output to verify under-excited capability. Also the test of leading capability at minimum real power loading should be held for five minutes. These tests are adequate to verify critical characteristics of the generator for use in studies. The four point tests may be difficult to obtain given system configuration and operation.
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve. The GVSDT recognizes that limitations may inhibit being able to achieve the desired testing levels. Any limitations should be entered in Attachment 2, "Remarks". The note states: "If the verification value did not reach the Thermal Capability Curve (D-Curve), describe the reason". This could include transmission system limitations.		
Independent Electricity System Operator	No	One of the purposes of Project 2007-09 is to ensure that generator models accurately reflect the generator's capabilities and operating characteristics. To achieve this, it is important that at least the minimum data requirements of entities that require these data are satisfied. This includes verifying the generating unit's capability curve or at least that portion of the curve between its minimum and maximum real power capability. We therefore recommend including a new bullet 2.3 in MOD-025 Attachment 1 similar to bullet 2.1 that requires verification of Real and Reactive Power capability of all generating units at maximum over-excited

Organization	Yes or No	Question 5 Comment
		and under-excited reactive capability at maximum gross Real Power capability (PMAX) where this is different from the generating unit's rated gross Real Power capability. The additional data points provided by this measurement (i.e. Qmax and Qmin at PMAX) will allow for a more complete verification of the generating unit's capability curve. Footnote 1 of MOD-025 Attachment 1 seems to use "rated gross Real Power" and "maximum [gross] Real Power" interchangeably. In general these two ratings may be different. We suggest deleting the footnote.
Response: The GVSDT thanks you for your comment. The GVSDT disagrees that testing at values above Pmax is needed to approximate the Reactive capability. Testing at additional points, however, is not prevented by the standard. The footnote was deleted, as you suggested.		
Ameren	No	While the testing regimen for the generator owners should not be made unduly burdensome, the four point test, if used to provide a straight line approximation of the generator capability, could result in somewhat more conservative reactive power operating limits for other real power levels as compared to a generating unit's published capability curve. The accuracy of the straight line approximation would vary on a generator-by-generator basis.
Response: The GVSDT thanks you for your comment. While not required by the standard, it is desirable to perform engineering analysis to determine expected unit capabilities under less restrictive system voltage than encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of unit capability that the Transmission Planner can use for modeling		
Indeck Energy Services	No	We don't agree that four points are needed for baseload units. We strongly agree with the Commission's statement that "such a requirement for all generators may not be necessary." First, we believe 2.2, of Attachment 1 to the standard, should exempt all base load units (not just nuclear units) from verification of reactive capability at minimum real power output. There are other units that the industry should be able to exempt based on their normal operating modes. Examples are peaker CTs and units that have restrictions (environmental, run of the river, etc.) preventing operation at minimum load. This concern is addressed in Paragraph 1321 of the FERC Order which states: "...other than baseload units, most generating units rarely operate at full MW loading. It is unclear what reactive capability is available throughout a unit's real power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit's real power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary." Also, we not believe that verification for leading capability should not be required where operational practices preclude operation in a leading mode. Finally, for units where verification of multiple points are needed to satisfy the FERC directive, we agree that 2 points are sufficient to verify the lagging capability and 2 points are sufficient to verify the leading capability

Organization	Yes or No	Question 5 Comment
		across the generator MW operating range. However, trying to represent that with a straight line approximation between the two points could eliminate a large portion of the available capability curve around rated pf when rated MW for the unit falls within the stator rating segment of the capability curve, especially when it approaches the stator limit (which can occur for some units).
Response: The GVSDT thanks you for your comment. The drafting team believes that four points represents the minimum number required to meet the FERC directive of multiple test points throughout the Load range to approximate the capability curve. Nuclear units are exempted from Reactive Power testing at low Real Power levels to minimize risks associated with changing reactor power levels. These same risks are not present for other base Load units. Analytical methods do not provide verification of equipment capability. The standard requires testing at the minimum Load that a unit is normally expected to operate. For units that have environmental or other restrictions, the standard does not require violating those restrictions.		
Oncor Electric Delivery Company LLC	No	Unit reactive capability is limited by many factors and cannot be estimated using a straight line approach, a region of reactive capability over various power levels using actual operating limits is more realistic.
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve and that this is a reasonable approximation. Additional testing, while not required, is allowed.		
Indiana Municipal Power Agency	No	IMPA believes that four point testing is excessive and that only two points need to be verified. Those two points would be over-excitged (lagging) and under-excited (leading) reactive capability at the rated Real Power capability only. The two points verified at the expected minimum Real Power output is excessive. Reactive power support happens when load is high and generating units are running at maximum Real Output capability.
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve.		
Chelan County PUD	Yes	It is adequate, but variation from testing at the extremes should be permitted due to conditions - in some applications it is difficult to go to full buck or boost without absorbine/providing the reactive power from another unit without impacting the voltage schedule. Should testing cause the voltage schedule to be violated (or worse an unacceptable voltage condition), what should govern? It is unreasonable to expect that every plant over 75MVA can go to these conditions and hold them for an hour.
Response: The GVSDT thanks you for your comment. While not required by the standard, it is desirable to perform engineering analysis to determine		

Organization	Yes or No	Question 5 Comment
expected unit capabilities under less restrictive system voltage than encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of unit capability that the Transmission Planner can use for modeling.		
Imperial Irrigation District (IID)	Yes	WE BELIEVE THAT FOUR POINTS IS SUBSTANTIAL INFORMATION FOR STRAIGHT LINE APPROXIMATION AS OVER-EXCITED (LAGGING) AND UNDER-EXCITED (LEADING) REACTIVE CAPABILITY AT RATED REAL POWER WOULD SOLELY BE A SUFFICIENT DATA FOR THIS PURPOSE.
Response: The GVSDT thanks you for your comment.		
PPL Generation	Yes	The proposed verification at multiple points over a unit's operating range appears to derive from a belief that the verification test results will follow the generator OEM's D-curve; and, owing to the abnormal voltages created by VAR testing and aux bus drop-out limitations; this will not be the case.
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve.		
SERC Dynamics Review Sub-committee	Yes	These 4 points should provide adequate testing of the generator. The DRS does not believe that verification for leading capability should be required where operational practices preclude operation in a leading mode.
Response: The GVSDT thanks you for your comment. The verification is intended to define the limits of the unit's capabilities. If a unit has no leading capability, then it should be reported with no leading capability or the minimum lagging capability at which it can operate. This has been added to Attachment 1, Note 4.		
Constellation Power Generation	Yes	CPG agrees that the points chosen would provide a sufficient approximation of a unit's capabilities. However, these capabilities will never match a generator's capability curve for a multitude of reasons, and as such, some verbiage should be included in the attachment under item 2 instead of as a note at the end of the document. Further, the limitations on the unit that may not allow the unit to perform to its capability curve are most likely designed into the control system as limiters or protection system components so as to not allow damage to the unit. These designed controls should not be "investigated for resolution" as stated in Note 1.
Response: The GVSDT thanks you for your comment. The standard doesn't require a unit to reach the capability curve value. The capability curve does not reflect all unit limitations that may exist. The limitation that is reached should be recorded on Attachment 2 in the remarks section. The limitations that you suggest are some of those expected to be identified with this standard. Item 2.1 has had the language "the generating unit's		

Organization	Yes or No	Question 5 Comment
normal (not emergency) expected maximum Real Power at the time of verification" inserted in the text rather than being included as a footnote. **The language in Attachment 1 Note 1 was changed to: "Could be further analyzed for resolution." If the limitation is by design, then no further investigation is necessary.**		
American Electric Power	Yes	The results of the test may not accurately reflect the VAR capability due to system conditions or alarm stopping the test and not reflect the actual generator limit in a real time scenario. This is discussed in Notes 1 and 2 of Attachment 1.
Response: The GVSDT thanks you for your comment.		
Ingleside Cogeneration LP	Yes	These operating points are more than sufficient to validate reactive capability in accordance with FERC's directive. However, Ingleside Cogeneration LP believes that it is sufficient and far less risky to perform the validation at the TOP's reactive capability schedule limits. In addition, there needs to be an allowance for known equipment limitations which prevent testing at the four test points. Similarly, unforeseen limitations which are determined during testing may prevent the validation at every extreme.
Response: The GVSDT thanks you for your comment. Note 1 of attachment 1 discusses limitations: **Note 1: Under some Transmission System, conditions, the data points obtained by the MVAR verification required by the standard will not duplicate the manufacturer supplied thermal capability curve (D-curve). However, the verification required by the standard, even when conducted under these transmission system conditions, may uncover applicable Facility limitations such as rotor thermal instability, improper tap settings, inaccurate AVR operation, etc. which could be further analyzed for resolution. Observe auxiliary bus voltage limits. The verified MVAR value obtained most likely will not be the value entered into the Transmission Planner's database; nor is it likely this value will agree with data required to be submitted by MOD-010.** **Any known equipment limitations should be entered in Attachment 2, "Remarks." The note states: "If the verification value did not reach the Thermal Capability Curve (D-Curve), describe the reason."**		
Duke Energy	Yes	We agree that four points are sufficient to provide a straight line approximation over a unit's operating range at points from Pmax and below, but additional consideration is needed for operation above Pmax. We don't agree that four points are needed for baseload units. We strongly agree with the Commission's statement that "such a requirement for all generators may not be necessary." The lagging capability curves have a break at rated pf. Trying to represent that with a single line with end point at Pmin and Pmax would eliminate a large portion of the available capability curve around rated pf. The leading capability might be more reasonably estimated by a linear assumption. Technically, nuclear units are base load plants as are some very large coal units and thus would not be expected to operate for any significant period of time at pmin, thus the term base

Organization	Yes or No	Question 5 Comment
		load is more appropriate than nuclear for excluding testing at Pmin First, we believe 2.2, of Attachment 1 to the standard, should exempt all base load units (not just nuclear units) from verification of reactive capability at minimum real power output. There are other units that the industry should be able to exempt based on their normal operating modes. Examples are peaker CTs and units that have restrictions (environmental, run of the river, etc.) preventing operation at minimum load.Finally, for units where verification of multiple points are needed, the analytical approach to verification,discussed in our responses to Questions 10, 11, and 14, serves this purpose very well.This concern is addressed in Paragraph 1321 of the FERC Order which states: "...other than baseload units, most generating units rarely operate at full MW loading. It is unclear what reactive capability is available throughout a unit's real power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit's real power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary."
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve. Nuclear units are exempted from Reactive Power testing at low Real Power levels to minimize risks associated with changing reactor power levels. These same risks are not present for other base Load units.		
Northeast Power Coordinating Council	Yes	
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	
SERC Planning Standards Subcommittee	Yes	
Arizona Public Service Company	Yes	
Westar Energy	Yes	
Salt River Project	Yes	
Tri-State Generation and Transmission, In.	Yes	

Organization	Yes or No	Question 5 Comment
Dynegy Inc.	Yes	
South Carolina Electric and Gas	Yes	
Xcel Energy	Yes	
American Wind Energy Association	Yes	
Tacoma Power	Yes	
Austin Energy	Yes	
Wisconsin Electric	Yes	
Northeast Utilities	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	
Wisconsin Public Service Corp	Yes	
Manitoba Hydro	Yes	
CPS Energy	Yes	
Gainesville Regional Utilities	Yes	
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
APS		being intentionally left blank (no answer to be provided)

6. Verification of over-excited reactive capability at rated Real Power Capability is required to be conducted over a minimum of one hour. Do you agree with the verification time? If not, please explain.

Summary Consideration: The overwhelming majority of stakeholders agree with the one-hour verification period. Several of the stakeholders who disagreed with the one-hour verification time suggested that we revise the verification time period to 15 minutes, 30 minutes, or two hours. The reliability goal of the one-hour verification is to ensure that temperatures on the generator are relatively stable and the verification reflects a capability that is sustainable. The GVSDT believes that the majority of generators will be sufficiently stable after one hour to meet the reliability objective of the standard. Some commenters suggested that one hour was not long enough to assure that temperatures have stabilized and that the unit capability is sustainable. The Standard has been modified in Attachment 1, 2.3 to say,

"Conduct the maximum Real Power and overexcited Reactive Power verifications required in 2.1 for a minimum of one continuous hour."

Organization	Yes or No	Question 6 Comment
IRC Standards Review Committee (joint comments)	No	See comment to Q2. The planner should ask for the data that it needs to comply with NERC standards (nothing more and nothing less). There is no need for the requirement to get into the details. The Planning standards will force the Planner to ask for the data that it needs for its models. This approach limits the Planners from asking for data that they do not use in their Planning Models or that is not needed to comply with a NERC standard. This approach also allows the Planner to tailor its requests to the Models and technologies that it has and needs.
Response: The GVSDT thanks you for your comment. Please see response to Question 2.		
SPP Reliability Standards Development Team	No	Currently SPP has criteria that the testing period should be 15 minutes rather than the listed 1 hour. We have found that this time period is adequate.
Response: The GVSDT thanks you for your comment. The overwhelming majority of stakeholders agree with the one-hour verification period. The reliability goal of the one-hour verification is to ensure that temperatures on the generator are relatively stable and the verification reflects a capability that is sustainable. The GVSDT believes that the majority of generators will be sufficiently stable after one hour to meet the reliability objective of the		

Organization	Yes or No	Question 6 Comment
standard.		
Idaho Power-Power Production	No	No, if this is intended to verify an emergency reactive capability we believe 15 minutes is sufficient. If this is intended to verify a normal reactive capability then 1 hour is reasonable.
Response: The GVSDT thanks you for your comment. The overwhelming majority of stakeholders agree with the one-hour verification period. The reliability goal of the one-hour verification is to ensure that temperatures on the generator are relatively stable and the verification reflects a capability that is sustainable. The GVSDT believes that the majority of generators will be sufficiently stable after one hour to meet the reliability objective of the standard. The standard is aimed at verification of normal reactive capability.		
PPL Generation	No	The one-hour period appears to derive from D-curve (thermal limiting) expectations; and, as explained above, this will not be the case
Response: The GVSDT thanks you for your comment. The overwhelming majority of stakeholders agree with the one-hour verification period. The reliability goal of the one hour verification is to ensure that temperatures on the generator are relatively stable and the verification reflects a capability that is sustainable. The GVSDT believes that the majority of generators will be sufficiently stable after one hour to meet the reliability objective of the standard.		
NERC Staff	No	Often, on larger units, temperatures do not stabilize within one hour. It is important for this test to assure that temperatures have stabilized and that the unit capability is sustainable, so the overexcited reactive capability test should be conducted for a minimum of two hours or until the temperatures have stabilized.
Response: The GVSDT thanks you for your comment. The overwhelming majority of stakeholders agree with the one-hour verification period. The reliability goal of the one-hour verification is to ensure that temperatures on the generator are relatively stable and the verification reflects a capability that is sustainable. The GVSDT believes that the majority of generators will be sufficiently stable after one hour to meet the reliability objective of the standard. Attachment 1, 2.3 states: **"Conduct the rated Real Power and overexcited Reactive Power verifications required in 2.1 for a minimum of one continuous hour.** **It is up to the entity testing the unit to determine when the temperatures are stable."**		
Arizona Public Service Company	No	30 minutes are more than adequate. All components reach steady state temperatures within that time. There is no need to be there more than 30 minutes.
Response: The GVSDT thanks you for your comment. The overwhelming majority of stakeholders agree with the one-hour verification period. The reliability goal of the one-hour verification is to ensure that temperatures on the generator are relatively stable and the verification reflects a capability		

Organization	Yes or No	Question 6 Comment
that is sustainable. The GVSDT believes that the majority of generators will be sufficiently stable after one hour to meet the reliability objective of the standard.		
PacifiCorp	No	First, PacifiCorp believes that over-excited reactive capability at rated Real Power verification should be performed on the same basis as for under-excited reactive capability and over-excited reactive capability at expected minimum Real Power output - that such data should be recorded as soon as a limit is reached. Second, this does not adequately take operating conditions for wind facilities into consideration.
Response: The GVSDT thanks you for your comment. The GVSDT believes that a stabilization period is needed to assure that verified data is sustainable. The GVSDT also believes that the rated power lagging test is the most demanding so that extended operation at other test points would not be required. Item 2.1 was revised in Attachment 1 to provide better clarity around testing requirements for wind facilities. **"If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, the Generator Owner must document the reasons it was unable to meet the threshold and test to the full capability at the time of the test. The Generator Owner shall retest the Facility within six months of being able to reach the 90 percent threshold. Maintain as steady as practical Real and Reactive Power output during verifications."**		
Cowlitz County PUD	No	Cowlitz suggests that "rated" be replaced with "normal expected maximum" in requirement 2.1 and "maximum" in requirement 2.3; although the footnote makes the intent clear, there is no need to complicate the reading of the Attachment and effectively redefine the normal understanding of the word rating. As far as running the test at least one hour, this commenter is not sure how quickly a unit achieves thermal stability. Again, Cowlitz questions if the data will be used and its actual contribution to improved modeling and future planning.
Response: The GVSDT thanks you for your comment. The GVSDT agrees and has made the revision Attachment 1, Item 2.1 has had the language "the generating unit's normal (not emergency) expected maximum Real Power at the time of verification," inserted in the text rather than being included as a footnote. Attachment 1, item 2.3 was revised as suggested.		
Xcel Energy	No	Southwestern Power Pool testing criteria specifies a 15 minute hold point and WECC requires holding until the temperatures are stable, which has always been less than one hour. We believe one hour is excessively long, and instead recommend a 15 minute verification time.
Response: The GVSDT thanks you for your comment. The overwhelming majority of stakeholders agree with the one-hour verification period. The reliability goal of the one-hour verification is to ensure that temperatures on the generator are relatively stable and the verification reflects a capability that is sustainable. The GVSDT believes that the majority of generators will be sufficiently stable after one hour to meet the reliability objective of the standard. Some commenters suggested that one hour was not long enough to assure that temperatures have stabilized and that the unit capability is		

Organization	Yes or No	Question 6 Comment
sustainable. The Standard has been modified in Attachment 1, 2.3 to say: "Conduct the maximum Real Power and overexcited Reactive Power verifications required in 2.1 for a minimum of one continuous hour."		
Manitoba Hydro	No	To obtain more realistic rated real power and over-excited reactive power ratings, the minimum verification time should be 2 hours or until temperatures have stabilized. For under-excitation, the test duration should be 1 hour.
Response: The GVSDT thanks you for your comment. The overwhelming majority of stakeholders agree with the one-hour verification. The reliability goal of the one-hour verification is to ensure that temperatures on the generator are relatively stable and the verification reflects a capability that is sustainable. The GVSDT believes that the majority of generators will be sufficiently stable after one hour to meet the reliability objective of the standard.		
CPS Energy	No	30 minutes should be sufficient time to verify capability.
Response: The GVSDT thanks you for your comment. The overwhelming majority of stakeholders agree with the one-hour verification. The reliability goal of the one-hour verification is to ensure that temperatures on the generator are relatively stable and the verification reflects a capability that is sustainable. The GVSDT believes that the majority of generators will be sufficiently stable after one hour to meet the reliability objective of the standard.		
Gainesville Regional Utilities	No	We suggest 30 minutes. While it may take an hour to reach full stabilized temperatures the probability of being called to perform form greater than 30 minutes is remote.
Response: The GVSDT thanks you for your comment. The overwhelming majority of stakeholders agree with the one-hour verification period. The reliability goal of the one-hour verification is to ensure that temperatures on the generator are relatively stable and the verification reflects a capability that is sustainable. The GVSDT believes that the majority of generators will be sufficiently stable after one hour to meet the reliability objective of the standard.		
Chelan County PUD	No	What is the basis for an hour? It should be tested to demonstrate stability at that point and not trip. After that why stay at an extreme condition? If you are concerned about MVA verification that can be done at any value, certainly design output and power factor is a better point.
Response: The GVSDT thanks you for your comment. The reliability goal of the one-hour verification period is to ensure that temperatures on the generator are relatively stable and the verification reflects a capability that is sustainable. The GVSDT believes that the majority of generators will be sufficiently stable after one hour to meet the reliability objective of the standard.		

Organization	Yes or No	Question 6 Comment
Tacoma Power	No	Depending on the size of the unit and location in the transmission system operating the unit at full rated reactive capability with normal steady state transmission voltages may subject the plant and transmission system to a sustained overvoltage. The over-excitation limit should be verified in the same way the under-excitation limit is verified.
Response: The GVSDT thanks you for your comment. Operation beyond the capability of the equipment is not expected nor required. The GVSDT believes that a stabilization period is needed to assure that verified data is sustainable. The GVSDT also believes that the rated power lagging test is the most demanding so that extended operation at other test points would not be required.		
Austin Energy	No	The ERCOT required verification time is 15 minutes. Extending the verification time to one hour is burdensome with unclear benefit.
Response: The GVSDT thanks you for your comment. The overwhelming majority of stakeholders agree with the one-hour verification. The reliability goal of the one-hour verification is to ensure that temperatures on the generator are relatively stable and the verification reflects a capability that is sustainable. The GVSDT believes that the majority of generators will be sufficiently stable after one hour to meet the reliability objective of the standard.		
Ingleside Cogeneration LP	No	Ingleside agrees in principle that one hour is sufficient at this test point, but believes it should take place at the limit identified in the Transmission Operator's reactive capability schedule.
Response: The GVSDT thanks you for your comment. The requirement is intended to verify the D-Curve of the generator for planning studies, not Real-time operations.		
American Electric Power	Yes	This requirement is stated in Attachment 1, section 2.3.
Response: The GVSDT thanks you for your comment.		
ISO New England	Yes	Yes, the standard should also require a recording of generator vibration during the test and require that the Generator Owner report an increase in vibration over the test period indicating the presence of rotor shorted turns that would limit long term generator MVAR loading. One hour may be enough time to determine if rotor shorted turns are present as indicated by vibration but the vibration must be recorded. The reactive power output data recording should be at 5 minute intervals and use the average for the hour. Also testing leading capability at minimum real power loading should be held for five minutes.
Response: The GVSDT thanks you for your comment. The GVSDT believes that a one-hour period is sufficient for most units to be stable, regardless		

Organization	Yes or No	Question 6 Comment
of the reason. Although vibration is a potential indicator of problems such as thermal stability in the field, if it can be held to operable levels for an hour that is sufficient for planning purposes. The GVSDT believes that data recorded at the end of the test is sufficient for planning purposes.		
BC Hydro	Yes	It may be better to specify a particular rate of change of measured temperature determining that heating has stabilized instead of selecting an arbitrary time period.
Response: The GVSDT thanks you for your comment. The overwhelming majority of stakeholders agree with the one-hour verification. The reliability goal of the one hour verification is to ensure that temperatures on the generator are relatively stable and the verification reflects a capability that is sustainable. The GVSDT believes that the majority of generators will be sufficiently stable after one hour to meet the reliability objective of the standard.		
FirstEnergy	Yes	Although we are OK with the 1 hour interval, we are not convinced this will meet the reliability goals of the standard. Just being able to hit a specific reactive output is one thing, but that does not assure Reliability. Most large generators and large main transformers have only reached one, possibly two, thermal time constants within an hour timeframe There are many thermal problems that can be identified if the electrical equipment is permitted to be operated at high load levels over an extended period of time. It may be necessary to show that reactive output can be maintained over a longer period of time.
Response: The GVSDT thanks you for your comment. The overwhelming majority of stakeholders agree with the one-hour verification period. The reliability goal of the one-hour verification is to ensure that temperatures on the generator are relatively stable and the verification reflects a capability that is sustainable. The GVSDT believes that the majority of generators will be sufficiently stable after one hour to meet the reliability objective of the standard.		
Public Service Enterprise Group	Yes	The drafting team should provide the rationale for the one hour minimum for over-excited reactive capability.
Response: The GVSDT thanks you for your comment. The reliability goal of the one-hour verification period is to ensure that temperatures on the generator are relatively stable and the verification reflects a capability that is sustainable. The GVSDT believes that the majority of generators will be sufficiently stable after one hour to meet the reliability objective of the standard.		
SERC Generation sub-committee	Yes	Provided that the verification is accomplished through staged testing or through operational data review. This requirement would not apply if the verification is accomplished using an engineering analysis method (see this proposal in comments to Question 14).
Response: The GVSDT thanks you for your comment. The GVSDT believes this requirement would apply regardless of using a staged test or operational data.		

Organization	Yes or No	Question 6 Comment
Southern Company	Yes	Provided that the verification is accomplished through staged testing or through operational data review. This requirement would not apply if the verification is accomplished using an engineering analysis method (see this proposal in comments to Question 14).
Response: The GVSDT thanks you for your comment. The GVSDT believes this requirement would apply regardless of using a staged test or operational data. See response to Question 14.		
Associated Electric Cooperative, Inc.	Yes	Provided that the verification is accomplished through staged testing or through operational data review. This requirement would not apply if the verification is accomplished using an engineering analysis method.
Response: The GVSDT thanks you for your comment. The GVSDT believes this requirement would apply regardless of using a staged test or operational data.		
Duke Energy	Yes	Provided that the verification is accomplished through staged testing or through operational data review and a unit is capable of reaching the expected over excited capability, 1 hour should be adequate to determine if equipment temps that might limit capability are stabilized. This requirement would not apply if the verification is accomplished using an engineering analysis method (see this proposal in comments to Question 14).
Response: The GVSDT thanks you for your comment. The GVSDT believes this requirement would apply regardless of using a staged test or operational data. See response to Question 14.		
Exelon	Yes	The time of one hour as a minimum is reasonable; however, the reactive capability may not able to be tested at the rated Real Power Capability. It may not be feasible to perform both Real and Reactive tests at the same time. Considerations must be given for the generator reactive capability curve (RCC).
Response: The GVSDT thanks you for your comment. The standard has been revised to clarify that Real and Reactive Power testing may be done at different times (see Summary Response to question 1).		
Northeast Power Coordinating Council	Yes	
Imperial Irrigation District (IID)	Yes	
Midwest Reliability Organization's	Yes	

Organization	Yes or No	Question 6 Comment
NERC Standards Review Forum (NSRF)		
Dominion	Yes	
SERC Dynamics Review Sub-committee	Yes	
Westar Energy	Yes	
Tennessee Valley Authority GO	Yes	
Luminant Power	Yes	
Salt River Project	Yes	
Dynegy Inc.	Yes	
New York Independent System Operator	Yes	
Tri-State Generation and Transmission, In.	Yes	
American Wind Energy Association	Yes	
Georgia Transmission Corporation	Yes	
Wisconsin Electric	Yes	
Great River Energy	Yes	

Consideration of Comments on First Posting of MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability (Project 2007-09)

Organization	Yes or No	Question 6 Comment
Northeast Utilities	Yes	
Constellation Power Generation	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	
Independent Electricity System Operator	Yes	
Ameren	Yes	
Indeck Energy Services	Yes	
Oncor Electric Delivery Company LLC	Yes	
Indiana Municipal Power Agency	Yes	
Wisconsin Public Service Corp		No Comment.
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
APS		being intentionally left blank (no answer to be provided)
Response: The GVSDT thanks you for your comment.		

7. Verification of (1) under-excited Reactive capability at rated Real Power of the most recent gross verified Real Power capability reported, (2) under-excited Reactive capability at expected minimum Real Power output and (3) over-excited Reactive capability at expected minimum Real Power output are all to be recorded as soon as a limit is encountered. Do you agree that such data recorded as soon as a limit is encountered is appropriate for such verification? If not, please explain.

Summary Consideration: The majority of stakeholders agree that the data should be recorded as soon as a limit is reached. A few stakeholders suggested that a holding or settling time be added to make certain that a limit was reached. Several stakeholders suggested that minimum Load testing, minimum Load over-excited testing or under-excited testing of nuclear units was not needed or desirable. The following statement was added to Note 1 of Attachment 1 for clarity:

"Auxiliary bus voltage limits should be observed."

Organization	Yes or No	Question 7 Comment
Consolidated Edison Co. of NY, Inc.	No	We recommend allowing the Transmission Operator (TOP) flexibility in determine the specific detailed nature of the reactive power tests performed in support its modeling. Regarding Part 2.1, in the NYISO, the maximum reactive power is tested at a real power level above 90% of maximum real power capability. The test was designed in this manner for a two reasons: (1) not to be a simultaneous test with 100% real power test and (2) to provide a reliable maximum reactive power test when the unit is stressed, but is still capable of providing reserve power. We recommend providing the TOP flexibility in this requirement by allowing reactive power to be tested above 90% of maximum real power capability. The NYISO Ancillary Services Manual also contemplates that GO's will test lagging and leading reactive power during time periods more appropriate to their use. On p. 28 and p. 34 the manual states: o Lagging MVAr capability testing will normally be performed during on-peak hours. The VSS Supplier must operate at maximum Lagging MVAr for at least one hour for the test to be acceptable. o The Leading MVAr testing will normally be performed during off-peak hours. The Leading MVAr test shall be scheduled with the corresponding TO, who will inform the NYISO. Ref: http://www.nyiso.com/public/webdocs/documents/manuals/operations/ancserv.pdf Presumably, under the NYISO tariff the leading and lagging Reactive Power tests would not be performed at

Organization	Yes or No	Question 7 Comment
		the same time or necessarily at the same "rated gross Real Power capability."ISO-NE also notes that maximum leading and lagging reactive power may not be at the same real power output level. o Points #4 and #9 in Figure #1, the two [lagging and leading] break points, do not necessarily correspond to the same MW output of the Generator. Ref: http://www.iso-ne.com/rules_proceds/operating/isone/op14/op14b_rto_final.pdf Proposed language change to MOD-025 Attachment 1: 2.1. Perform verification of Real and Reactive Power capability of all generating units at maximum over-excited (lagging) and under-excited (leading) reactive capability at rated gross Real Power capability1, or at the Real Power level stipulated by the Transmission Operator. ...
Response: The GVSDT thanks you for your comment. The GVSDT reviewed the language in the NYISO document, Table 3.1. The table uses terms UCAP and ICAP. The revised standard contains language in Item 2.1 of Attachment 1 that states the verification is to be performed at "the generating unit's normal (not emergency) expected maximum Real Power at the time of the verification." A test to satisfy MOD-025 would appear to meet the requirements for the NYISO, while also meeting the statement, "Extreme measures that might overstate a unit's Reactive capability must be avoided," in Section 3.6.2 of the NYISO document.		
Northeast Power Coordinating Council	No	Regarding Part 2.1, in the NYISO reactive power is tested at a real power level above 90% of maximum. The tariff was designed in this manner for a few reasons: (1) not to be simultaneous test with 100% real power test and (2) provide a reliable maximum reactive test when the unit is stressed, but is still capable of providing reserve power. Recommend providing some flexibility in this requirement by stating that reactive power can be tested above 90% of maximum real power.
Response: The GVSDT thanks you for your comment. The GVSDT reviewed the language in the NYISO document, Table 3.1. The table uses terms UCAP and ICAP. The revised standard contains language in Item 2.1 of Attachment 1 that states the verification is to be performed at "the generating unit's normal (not emergency) expected maximum Real Power at the time of the verification." A test to satisfy MOD-025 would appear to meet the requirements for the NYISO, while also meeting the statement, "Extreme measures that might overstate a unit's reactive capability must be avoided," in Section 3.6.2 of the NYISO document.		
Northeast Utilities	No	Regarding Part 2.1, in the NYISO reactive power is tested at a real power level above 90% of maximum. The tariff was designed in this manner for a few reasons: (1) not to be simultaneous test with 100% real power test and (2) provide a reliable maximum reactive test when the unit is stressed, but is still capable of providing reserve power. Recommend providing some flexibility in this requirement by stating that reactive power can be tested above 90% of maximum real power.

Organization	Yes or No	Question 7 Comment
Response: The GVSDT thanks you for your comment. The GVSDT reviewed the language in the NYISO document, Table 3.1. The table uses terms UCAP and ICAP. The revised standard contains language in Item 2.1 of Attachment 1 that states the verification is to be performed at "the generating unit's normal (not emergency) expected maximum Real Power at the time of the verification." A test to satisfy MOD-025 would appear to meet the requirements for the NYISO, while also meeting the statement, "Extreme measures that might overstate a unit's reactive capability must be avoided," in Section 3.6.2 of the NYISO document.		
IRC Standards Review Committee (joint comments)	No	See comment to Q2. The planner should ask for the data that it needs to comply with NERC standards (nothing more and nothing less). There is no need for the requirement to get into the details. The Planning standards will force the Planner to ask for the data that it needs for its models. This approach limits the Planners from asking for data that they do not use in their Planning Models or that is not needed to comply with a NERC standard. This approach also allows the Planner to tailor its requests to the Models and technologies that it has and needs.
Response: The GVSDT thanks you for your comment. Please see response to question 2.		
SPP Reliability Standards Development Team	No	We would request that the time be a few minutes to make sure after a settling period that it was a limit that was encountered.
Response: The GVSDT thanks you for your comment. The GVSDT feels that the time needed to take data should be a sufficient settling period.		
Dominion	No	For items 2 and 3 see comments in question 5. We agree with item 1.
Response: The GVSDT thanks you for your comment. Please see response to question 5.		
Westar Energy	No	We suggest that the SDT considering adding clarifying language around "as soon as a limit is encountered." The current language is ambiguous.
Response: The GVSDT thanks you for your comment. The GVSDT believes the language is clear. We welcome suggested edits that you believe would provide the clarity that you seek.		
New York Independent System Operator	No	Testing requirements for reactive capability at minimum real power output should be removed. These tests are of no value and lead to system limit concerns. The testing requirement should be changed to two test points. One test for an hour to verify over-excited (lagging) capability at the real power level specified by the Transmission Operator or the Transmission Planner. A second test to verify under-excited capability (leading)

Organization	Yes or No	Question 7 Comment
		at the real power level specified by the Transmission Operator or the Transmission Planner.
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve. Also, while not required by the standard, it is desirable to perform engineering analysis to determine expected unit capabilities under less restrictive system voltage than encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of unit capability that the Transmission Planner can use for modeling.		
Cowlitz County PUD	No	Cowlitz at this time has insufficient information to formulate an opinion, but at the same time is skeptical of the reliability benefit being great enough to justify the cost of obtaining this data.
Response: The GVSDT thanks you for your comment. The data us being collected as a result of a FERC directive in paragraph 1321 which states: **"1321. We disagree with commenters that verifying generator Reactive capability is a particularly difficult issue. The capability of generators to produce Reactive Power is essential for Real-time analysis and planning. The Reliability Standard addressing this issue requires a generator to verify Reactive capability only at the unit's full MW Loading. However, other than base load units, most generating units rarely operate at full MW Loading. It is unclear what Reactive capability is available throughout a unit's Real Power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit's Real Power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary. Therefore, we adjust the proposal in the NOPR and direct the ERO to modify MOD-025-1 to require verification of reactive power capability at multiple points over a unit's operating range.**		
Ameren	No	(1) From transmission perspective: If a plant limit is encountered in the testing, and it is a hard limit not to be exceeded, then the capability at this limit should be recorded. If a limit is identified on the transmission system such that the testing cannot be completed, then the capability should be noted but this would not be a firm limit. (2) From GO perspective : Our testing people won't know if the transmission system is causing the limit because they aren't allowed to "see" the transmission system. Second, they are not allowed to test at time of seasonal peak because their testing may jeopardize the availability of the unit and testing during the fall and spring will mean higher voltages and frequently some type of testing limit is reached. Engineering calculations and justification should be allowed. Finally, we thought the 20% "margin" was to allow for these unavoidable risk restraints on testing the units. If a plant limit is encountered in the testing, then the capability at this limit should be recorded. However, it is unclear how this data, and the 20% margin, should be used in the verification process. We request the SDT clarify how data readings within the 20% margin should be used to determine the Real and Reactive capabilities of a generator or plant.

Organization	Yes or No	Question 7 Comment
Response: The GVSDT thanks you for your comment. The GVSDT agrees that an entity should record data for a hard limit when the unit reaches the limit. While not required by the standard, it is desirable to perform engineering analysis to determine expected unit capabilities under less restrictive system voltages than those encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of unit capability that the Transmission Planner can use for modeling. Communication with the Transmission Operator is necessary when performing testing and system voltage limits would be part of that communication. The 20% margin was meant to be a permissive limit to accept operational data. The 20% value was removed and the wording of Item 2 in Attachment 1 has been modified in the standard based on industry feedback. 2. Perform verification with all auxiliary equipment needed for expected normal operation in service for both the Real Power and Reactive Power capability verification, and the automatic voltage regulator in service for the Reactive Power capability verification (see Note 3 if the automatic voltage regulator is not available). Operational data from within the two years prior to the verification date is acceptable for the verification, as long as it meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50% of the capability shown on the appropriate D-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations(for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data:		
Indeck Energy Services	No	Only if they are required for particular units.
Response: The GVSDT thanks you for your comment. The test points are required for all applicable units.		
Ingleside Cogeneration LP	No	Ingleside agrees in principle that a demonstration that the generator can reach these test points is sufficient, and reduces the risk to the equipment. However, the limits identified in the Transmission Operator's reactive capability schedule should be verified, not the generator's operational limits.
Response: The GVSDT thanks you for your comment. The intent of MOD-025 is to verify generator capability for long-term planning studies. Real-time issues with a Transmission Operators voltage schedule are not included in this standard.		
ISO New England	No	These types of tests should require remaining at the point for a length of time. Under-excited power verification at minimum power output for five minutes should be adequate. Testing requirements for over-excited reactive capability at minimum real power output and under-excited capability at maximum power should be removed. These tests lead to transmission system voltage concerns.
Response: The GVSDT thanks you for your comment. The GVSDT believes that the time required to take the data is sufficient for under-excited tests.		

Organization	Yes or No	Question 7 Comment
The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve. Communication with the Transmission Operator is necessary when performing testing and system voltage limits would be part of that communication.		
Public Service Enterprise Group	Yes	This documents the system conditions and unit conditions when limits are reached.
Response: The GVSDT thanks you for your comment.		
Great River Energy		GRE would object to doing this at URGE because URGE is not our normal operating condition. The reactive power testing should be done at normal full load (normal operating conditions) to be representative of how much reactive power the unit can put out or absorb during normal running conditions. GRE doesn't agree with doing the under and over-excited limits at min. power levels. Mainly for baseload units, this is not representative of where the units run. Also, this would be costly when you are taking a baseload unit to min. load for the testing. There are also many unit specific conditions that exist that may prevent an unit from running at its true minimum load.
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve.		
GenOn Energy	Yes	The intent of the question is not well understood. The answer is complicated by the inability to replicate the system condition that will demand the unit operating limits, creating artificial lower limits under the test conditions.
Response: The GVSDT thanks you for your comment.		
SERC Generation sub-committee	Yes	But, we believe that there is little value to a minimum load, vars-out requirement. Also, it will be difficult to achieve since the system usually has minimum VAR output requirements when operating at minimum load. Experience has shown that a large unit cannot reach the full available lagging (many times) or leading (most times) reactive capability values due to voltage limitations. That does not mean that that capability is not available. This is exemplified by the testing of a large fossil unit below (attempted to include graphic).
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve. Also, while not required by the standard, it is desirable to perform engineering analysis to determine expected unit capabilities under less restrictive system voltage than encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of unit capability that the Transmission		

Organization	Yes or No	Question 7 Comment
Planner can use for modeling.		
Tennessee Valley Authority GO	Yes	But, we believe that there is little value to a minimum load, vars-out requirement. Also, it will be difficult to achieve since the system usually has minimum VAR output requirements when operating at minimum load. Experience has shown that a large unit cannot reach the full available lagging (many times) or leading (most times) reactive capability values due to voltage limitations. That does not mean that that capability is not available.
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve. Also, while not required by the standard, it is desirable to perform engineering analysis to determine expected unit capabilities under less restrictive system voltage than encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of unit capability that the Transmission Planner can use for modeling.		
Southern Company	Yes	We believe that the minimum load, it will be difficult for a unit to produce Vars because the system usually has minimum VAR output requirements from generators when the generators are operating at minimum load. Therefore, we believe verification of Vars out at minimum load will not provide the data that transmission planning is seeking and, therefore, this requirement is not necessary. See our response to Question 5 for additional discussion on verification at minimum load.
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve. Also, while not required by the standard, it is desirable to perform engineering analysis to determine expected unit capabilities under less restrictive system voltage than encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of unit capability that the Transmission Planner can use for modeling.		
Associated Electric Cooperative, Inc.	Yes	We believe that there is little value to a minimum load, vars-out requirement. Also, it will be difficult to achieve since the system usually has minimum VAR requirements when operating at low system load. Experience has shown that a large unit cannot reach the full available lagging (many times) or leading (most times) reactive capability values due to voltage limitations. That does not mean that that capability is not available.
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve. Also, while not required by the standard, it is desirable to perform engineering analysis to determine expected unit capabilities under less restrictive system voltage than encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of unit capability that the Transmission		

Organization	Yes or No	Question 7 Comment
Planner can use for modeling.		
Duke Energy	Yes	We believe that there is little value to a minimum load, vars-out requirement. Also, it will be difficult to achieve since the system usually has minimum VAR output requirements when operating at minimum load. Experience has shown that a large unit cannot reach the full available lagging (many times) or leading (most times) reactive capability values due to voltage limitations. That does not mean that that capability is not available. This is exemplified by the testing of a large fossil unit (Graphic has been provided to the SDT). There needs to be standards on how model values are selected, such as, o The lagging capabilitiy values should be based on 90% of gross generator capability at minimum normal Hydrogen pressure minus aux system loads and xfmr losses o The leading capability values being modeled should be based on (UEL limiter setpoints as documented by PRC-19 coordination is probably appropriate).
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve. Also, while not required by the standard, it is desirable to perform engineering analysis to determine expected unit capabilities under less restrictive system voltage than encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of unit capability that the Transmission Planner can use for modeling.		
Exelon	Yes	Recording the test data as soon as a limit is encountered is reasonable; however, the reactive capability may not able to be tested at the rated Real Power Capability. It may not be feasible to perform both Real and Reactive tests at the same time. Considerations must be given for the reactive limits given by the plant specific generator reactive capability curve (RCC) at the attainable real power output. Currently Attachment 1 states that nuclear units are excluded from performing Reactive Power verification at minimum Real Power output. This exclusion must be extended to include a statement that nuclear units are not required to perform under-excited (leading) reactive capability verification testing. Nuclear units do not perform under-excited (leading) reactive capability testing due to concerns with unit stability and potential under voltage conditions on internal nuclear plant safety buses that may challenge safe plant operations and could lead to a plant transient or shutdown in accordance with NRC operating license. Suggest the following revision to Attachment 1 as follows:2.2 Verify Reactive Power of all generating units other than wind and photovoltaic for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they could normally be expected to operate. Nuclear Units are not required to perform under-excited (leading) reactive capability verification testing or Reactive Power verification at minimum Real Power output.

Organization	Yes or No	Question 7 Comment
Response: The GVSDT thanks you for your comment. Language has been added to make it clear that Real and Reactive Power tests are not required to be performed at the same time. The GVSDT feels that if a nuclear plant has under-excited capability it should be tested within the unit's capability and declared safety margins. The standard does not require challenging unit capabilities. The following statement was added to Note 1 of Attachment 1 for clarity, "Auxiliary bus voltage limits should be observed."		
Luminant Power	Yes	See Luminant comments to Question #5 regarding operating ranges for testing.
Response: The GVSDT thanks you for your comment. Please see response to question 5.		
BC Hydro	Yes	Only verification of (1) has practical significance; (2) and (3) are redundant. Please see Comment 5.
Response: The GVSDT thanks you for your comment. Please see response to question 5.		
American Electric Power	Yes	This is stated in Attachment 1, section 2.4. A clarification could be in order to relate the recording of the time when the limit is reached to the requirement that the test be conducted over a one hour interval. For example, if a limit is reached in 15 minutes, is the verification test completed or is the expectation that the unit is held at that level for the balance of the one hour test window. Also, it is curious why this question excludes the condition of over-excited reactive capability at the rated gross real power per Attachment 1, section 2.1.
Response: The GVSDT thanks you for your comment. The intent, as stated, is that the Reactive Power lagging test at rated Real Power and the Real Power test be held for one hour; once that level is attained, to allow the unit to stabilize before taking data. All other reactive power tests need only be held long enough to take data.		
Imperial Irrigation District (IID)	Yes	
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	
Idaho Power-Power Production	Yes	
PPL Generation	Yes	
FirstEnergy	Yes	

Consideration of Comments on First Posting of MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability (Project 2007-09)

Organization	Yes or No	Question 7 Comment
SERC Dynamics Review Sub-committee	Yes	
NERC Staff	Yes	
Arizona Public Service Company	Yes	
Salt River Project	Yes	
PacifiCorp	Yes	
Dynegy Inc.	Yes	
Tri-State Generation and Transmission, In.	Yes	
Xcel Energy	Yes	
American Wind Energy Association	Yes	
Tacoma Power	Yes	
Georgia Transmission Corporation	Yes	
Austin Energy	Yes	
Wisconsin Electric	Yes	
Constellation Power Generation	Yes	
Wisconsin Public Service Corp	Yes	

Consideration of Comments on First Posting of MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability (Project 2007-09)

Organization	Yes or No	Question 7 Comment
Manitoba Hydro	Yes	
CPS Energy	Yes	
Independent Electricity System Operator	Yes	
Gainesville Regional Utilities	Yes	
Oncor Electric Delivery Company LLC	Yes	
Indiana Municipal Power Agency	Yes	
Chelan County PUD	Yes	
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
APS		being intentionally left blank (no answer to be provided)

8. Synchronous condensers are also reactive resources that may be important to reliability, but they are not generators. The SDT proposes that synchronous condensers be verified under MOD-025-2. Do you feel that this is appropriate?

Summary Consideration: There was overwhelming stakeholder support for verifying synchronous condensers as a Reactive resource under MOD-025-2. Some stakeholders suggested that consideration be given under this or a different standard for verification of other Reactive resources.

The SDT added the following sentence to the first paragraph of Attachment 1 in response to a stakeholder comment: "If a unit is operated in synchronous condenser mode as well as generation mode, the unit should be verified in both modes."

Organization	Yes or No	Question 8 Comment
Ingleside Cogeneration LP	No	There is a significant body of work underway defining the extent of the Bulk Electric System, which this proposal bypasses. This determination should rest with the project team responsible for that effort.
Response: The GVSDT thanks you for your comment. The GVSDT has sufficient expertise to recommend synchronous condensers be included under the verification requirements of MOD-025 to help ensure the reliability of the BES.		
Indeck Energy Services	No	They are owned and registered differently.
Response: The GVSDT thanks you for your comment. Synchronous condensers are not currently included in the compliance registry. The GVSDT has sufficient expertise to recommend synchronous condensers be included under the verification requirements of MOD-025 and, hence, the compliance registry, to help ensure the reliability of the BES.		
Oncor Electric Delivery Company LLC	No	Oncor does not believe that there is a reliability based need for the verification of synchronous condensers under this standard
Response: The GVSDT thanks you for your comment. The GVSDT disagrees and has included Reactive verification for synchronous condensers.		
Southern Company	No	

Organization	Yes or No	Question 8 Comment
Imperial Irrigation District (IID)	Yes	THERE ARE NO SYNCHRONOUS CONDENSERS INSTALLED AND IN SERVICE WITHIN IID FACILITY.
Response: The GVSDT thanks you for your comment.		
Pepco Holdings Inc Affiliates	Yes	However, based on the requirements and measures identified in the standard it is unclear why the standard was made applicable to Transmission Owners; unless the standard is intended to only apply to Transmission Owners that own synchronous condensers. If that is the case, Section A- 4.1.2 should be re-written as follows: "Transmission Owner that owns a synchronous condenser." This qualification is consistent with other PRC standards (PRC-010, PRC-015, PRC-023, etc.) where applicability to a specific sub-set of Transmission Owners is clearly defined.
Response: The GVSDT thanks you for your comment. The standard applies to TOs that may own synchronous condensers, and this is reflected in Section 4.1.2, as suggested..		
FirstEnergy	Yes	Yes, we believe they should be verified because they are the same type of dynamic, voltage independent, source of reactive power as is a real power generator. We also believe that they certainly are generators, generators of reactive power. In fact, they are identical in function, design and equipment as a real power generator, minus the prime mover. A synchronous condenser, like its sister the real power generator, can be continuously adjusted for the desired output and contains equipment that must be properly adjusted to provide the desired range of reactive output.
Response: The GVSDT thanks you for your comment. The GVSDT concurs with your comments.		
SERC Dynamics Review Sub-committee	Yes	Synchronous condensers supply reactive power to the grid. Therefore, the Transmission Planner needs to know a verified capability for the device.
Response: The GVSDT thanks you for your comment.		
NERC Staff	Yes	Although the penetration of synchronous condensers in North America is low, in most cases they are applied to address a reliability need, making it necessary to have accurate models of these devices for system studies. Although other devices may be outside the scope of this standard, accurate models are similarly necessary for devices such as static var compensators (SVCs) and static compensators (STATCOMs).
Response: The GVSDT thanks you for your comment. Synchronous condensers are synchronous machines, so the GVSDT feels they should be included with other synchronous machines. Solid state devices are significantly different, and the GVSDT believes that a separate SAR should be		

Organization	Yes or No	Question 8 Comment
drafted to cover these devices.		
Manitoba Hydro	Yes	To cover all configurations, the standard should also include and stipulate that synchronous machines that operate as generators at some times and as synchronous condensers at other times must perform a reactive capability test in each operating mode. This may be covered in Applicability 4.2.1 however the current wording should be modified to make this clear.
Response: The GVSDT thanks you for your comment. The following sentence was added to the beginning of Attachment 1: **"If a unit is operated in synchronous condenser mode as well as generation mode, the unit should be verified in both modes."**		
Independent Electricity System Operator	Yes	The standard should also be applicable to static var compensators and similar equipment used in reliability assessments of the BES.
Response: The GVSDT thanks you for your comment. Synchronous condensers are synchronous machines so the GVSDT feels they should be included with other synchronous machines. Solid state devices are significantly different, and the GVSDT believes that a separate SAR should be drafted to cover these devices.		
ISO New England	Yes	Yes, but as written the standard is not clear as to how the testing is to be performed for a synchronous condenser.
Response: The GVSDT thanks you for your comment. The following was added to the beginning of Attachment 1: **"For synchronous condensers, the verification should be performed as specified below with the exception of the Real Power Capability testing."**		
Cowlitz County PUD		Cowlitz does not own such equipment and therefore must defer to those that do. Cowlitz will consider the comments of others in the future.
Response: The GVSDT thanks you for your comment.		
Northeast Power Coordinating Council	Yes	
IRC Standards Review	Yes	

Organization	Yes or No	Question 8 Comment
Committee (joint comments)		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	
SPP Reliability Standards Development Team	Yes	
SERC Planning Standards Subcommittee	Yes	
Idaho Power-Power Production	Yes	
PPL Generation	Yes	
Dominion	Yes	
Public Service Enterprise Group	Yes	
ACES Power Members	Yes	
Arizona Public Service Company	Yes	
Westar Energy	Yes	
Salt River Project	Yes	
PacifiCorp	Yes	
South Carolina Electric and Gas	Yes	
Associated Electric Cooperative, Inc.	Yes	

Consideration of Comments on First Posting of MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability (Project 2007-09)

Organization	Yes or No	Question 8 Comment
New York Independent System Operator	Yes	
Tri-State Generation and Transmission, In.	Yes	
Xcel Energy	Yes	
Exelon	Yes	
American Wind Energy Association	Yes	
Georgia Transmission Corporation	Yes	
Wisconsin Electric	Yes	
Great River Energy	Yes	
BC Hydro	Yes	
Northeast Utilities	Yes	
Constellation Power Generation	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	
American Electric Power	Yes	
Wisconsin Public Service Corp	Yes	

Organization	Yes or No	Question 8 Comment
GenOn Energy	Yes	
Duke Energy	Yes	
Gainesville Regional Utilities	Yes	
Ameren	Yes	
Indiana Municipal Power Agency	Yes	
Tacoma Power		None
SERC Generation sub-committee		No GS comment
APS		being intentionally left blank (no answer to be provided)
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.

9. The SDT proposes that the size of synchronous condensers to be verified be limited to those greater than 50 MVA. Do you feel that this size criterion for synchronous condenser verification is appropriate?

Summary Consideration: There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit. While some commenters suggested values higher than 20 MVA, technical justification was not provided for a value exceeding the generator registration criterion of 20 MVA.

Organization	Yes or No	Question 9 Comment
IRC Standards Review Committee (joint comments)	No	There is no technical justification provided to support the 50 MVA criterion. Absent this, we propose to use the 20 MVA for generators as a general criterion for synchronous condensers as well.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
Dominion	No	First, we would like to state that we did not see the 50 MVA threshold in the posted version of this standard. And, if we had, we would not have agreed. If 20 MVA is the appropriate threshold for a generator, it is appropriate for a synchronous condenser.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
SERC Planning Standards Subcommittee	No	We recommend a limit of 20 MVA since these may be in remote areas where reactive capability is critical.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		

Organization	Yes or No	Question 9 Comment
Southern Company	No	This MVA size does not agree with that found in the Applicability section 4.2.1 (20 MVA). As previously stated, we feel that the size of an individual unit that is significant in the Eastern Interconnection is 100 MVA.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
Tennessee Valley Authority GO	No	It is noted that this criteria is not consistent with the criteria for generators or with 4.2.1 of the draft standard.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
SERC Dynamics Review Sub-committee	No	A 50 MVA criteria for synchronous condensers is not in the standard. The standard says 20 MVA. However, a criteria of 75 MVA would be a more reasonable number. Units smaller than 75 MVA will have little impact to the reliability of the grid.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
NERC Staff	No	Section 4.2.1 indicates the standard is applicable to synchronous condensers greater than 20 MVA. We agree that the standard should be applicable to synchronous condensers greater than 20 MVA rather than 50 MVA.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
SERC Generation sub-committee	No	It is noted that this criteria is not consistent with the criteria for generators or with 4.2.1 of the draft standard.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
Associated Electric Cooperative, Inc.	No	It is noted that this criteria is not consistent with the criteria for generators or with 4.2.1 of the draft standard.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		

Organization	Yes or No	Question 9 Comment
New York Independent System Operator	No	100 MVA is a more appropriate limit.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
Independent Electricity System Operator	No	There is no technical justification provided to support the 50 MVA criterion. Absent this, we propose to use the 20 MVA for generators as a general criterion for synchronous condensers as well.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
Ameren	No	The size of synchronous condensers to be verified should be consistent with generator sizes which need to be verified. Testing for units less than 75 MVA should not be required.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
Oncor Electric Delivery Company LLC	No	Oncor does not believe that there is a reliability based need for the verification of synchronous condensers under this standard therefore we believe this criterion is not applicable to this standard.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit. Reactive output of synchronous condensers directly impacts the reliability of the BES.		
Georgia Transmission Corporation	No	20 MVA seems more consistent with the reasoning in question 4.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
Ingleside Cogeneration LP	No	There is a significant body of work underway defining the extent of the Bulk Electric System, which this proposal bypasses. This determination should rest with the project team responsible for that effort.

Organization	Yes or No	Question 9 Comment
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
Wisconsin Public Service Corp	No	Synchronous condensers are specifically for local area voltage regulation purposes. Units between the sizes of 20MVA to 50MVA could be significant to an area's dynamic performance under contingencies.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
ISO New England	No	There is no technical justification supporting the 50 MVA criterion. Absent this, we propose to use the Compliance Registry criteria for generators of 20 MVA as a general criterion for data being verified for synchronous condensers over 20 MVA as well.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
Manitoba Hydro	No	The 50MVA criteria in question 9 does not appear in the draft standard (only in the implementation plan). If the question is valid and 50MVA is not a typo, it is not clear why the size of applicable synchronous condensers should be different from that of synchronous generators. Also 50 MVA seems like an arbitrary number with no basis. MH proposes that the applicable MVA rating of synchronous generators and synchronous condensers be identical. This eliminates confusion associated with units capable of operating in either mode.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
Indeck Energy Services	No	
Public Service Enterprise Group		A 50 MVA minimum size for synchronous condensers was not found in the proposed standard - see paragraph 4.2.1 which has a 20 MVA minimum. Whether the limit was intended to be 50 MVA or the 20 MVA limit stated in the draft, the SDT should provide a justification of basis for that MVA threshold. The impact that such smaller units would have on the BES is not substantial enough to justify requiring their inclusion in this standard.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included		

Organization	Yes or No	Question 9 Comment
a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
Cowlitz County PUD		Cowlitz does not own such equipment and therefore must defer to those that do. Cowlitz will consider the comments of others in the future.
Response: The GVSDT thanks you for your comment.		
BC Hydro		Not clear why would verification be required for generating units over 20 MVA while for SCs the threshold is over 50 MVA, especially having in mind that SCs are specifically used to provide reactive support
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
Xcel Energy	Yes	There is a discrepancy between this question and the size limit in the draft standard (20 MVA). We believe 50 MVA is the better value.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
Westar Energy	Yes	We agree with the 50 MVA limit, however the standard does not currently address this limit.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
Imperial Irrigation District (IID)	Yes	THERE ARE NO SYNCHRONOUS CONDENSERS INSTALLED AND IN SERVICE WITHIN IID FACILITY.
Response: The GVSDT thanks you for your comment.		
Pepco Holdings Inc Affiliates	Yes	Question 9 mentions that a threshold was proposed by the SDT for synchronous generators greater than, or equal to, 50MVA. However, the existing language in Section A- 4.2.1 of the standard makes it applicable to both individual generating units and synchronous condensers greater than 20MVA. The 50MVA threshold for synchronous condensers seems reasonable, so if this was the intent then the language in the standard should be revised.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included		

Organization	Yes or No	Question 9 Comment
a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
SPP Reliability Standards Development Team	Yes	We agree with the 50 MVA limit but would request that it be included in the actual standard.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
FirstEnergy	Yes	The applicability section does not mention the 50 MVA threshold.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
American Electric Power	Yes	The current draft of the standard in section 4.2.1 proposes that the size of synchronous condensers to be verified be limited to those greater than 20 MVA, not 50MVA as stated in this question. Regardless, either limit would be acceptable.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	
Northeast Power Coordinating Council	Yes	
PPL Generation	Yes	
Arizona Public Service Company	Yes	
Salt River Project	Yes	
PacifiCorp	Yes	

Consideration of Comments on First Posting of MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability (Project 2007-09)

Organization	Yes or No	Question 9 Comment
South Carolina Electric and Gas	Yes	
Tri-State Generation and Transmission, In.	Yes	
Exelon	Yes	
American Wind Energy Association	Yes	
Wisconsin Electric	Yes	
Great River Energy	Yes	
Northeast Utilities	Yes	
Constellation Power Generation	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	
Gainesville Regional Utilities	Yes	
APS		being intentionally left blank (no answer to be provided)
Tacoma Power		None
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.

10. Either operational data or staged testing is allowed by the standard for verification. Do you agree that these two methods of verification are acceptable? If not, please explain.

Summary Consideration: Most stakeholders agree that either operational data or staged testing should be allowed for verification.

Organization	Yes or No	Question 10 Comment
SERC Generation sub-committee	No	As the draft is currently written, these two methods are understood to be allowed. However, we believe a third alternative, engineering analysis, is needed in order for GOs to be able to verify generating unit reactive capabilities that are suitable for transmission system planning studies (See our Comment 2 under Question 14 for additional discussion on the verification methods.). It is proposed that Requirement R1.1 be re-written as follows: "Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with either Attachment 1 (staged testing or operational data) or by a new Attachment 3 (addressing engineering analysis)." The SERC GS could provide a template for this. Requirement R1.2 could then be qualified to be limited to reporting the results from staged testing or the use of operational data, and a new R1.3 could be inserted to require suitable reporting of the results from an engineering analysis. The time horizon of the two requirements in this standard are Long-Term Planning. MOD-025-2 does not have to focus solely upon operational testing to determine capabilities used for planning entity models. It is noted that TOP-002-2a R13 now requires the GOP to perform real and reactive capability testing at the request of the BA or TOP. The test can be specified if determined to be necessary by the BA or TOP.

Response: The GVSDT thanks you for your comment. It is envisioned that engineering analysis may be used to supplement operational data or staged testing. The GVSDT does not believe that engineering analysis alone is sufficient. Attachment 1, Section 2 of the proposed standard states:

"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the capability shown on the associated D-Curve."

And Note 2 in Attachment 1 states:

Organization	Yes or No	Question 10 Comment
Note 2: "While not required by the standard, it is desirable to perform engineering analysis to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of applicable Facility capability that the Transmission Planner can use for modeling." **TOP-002-2a, R13 is proposed for retirement by the RTOSDT (Project 2007-03).**		
Southern Company	No	As the draft is currently written, these two methods are understood to be allowed. However, we believe a third alternative, engineering analysis, is needed in order for GOs to be able to verify generating unit reactive capabilities that are suitable for transmission system planning studies (See our Comment 2 under Question 14 for additional discussion on the verification methods.). Reliance on data from testing or operations alone will result in understated reactive capabilities for planning purposes. To provide these alternative methods of establishing P&Q capabilities for each applicable facility, it is proposed that Requirement R1.1 be re-written as follows: "Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with either Attachment 1 (staged testing or operational data) or Attachment 3 (by engineering analysis)." Requirement R1.2 could then be qualified to be limited to reporting the results from staged testing or the use of operational data, and a new R1.3 could be inserted to require suitable reporting of the results from an engineering analysis. The time horizon of the two requirements in this standard are Long-Term Planning. MOD-025-2 does not have to focus solely upon operational testing to determine capabilities used for planning entity models. It is noted that TOP-002-2a R13 now requires the GOP to perform real and reactive capability testing at the request of the BA or TOP. The test can be specified if determined to be necessary by the BA or TOP.
Response: The GVSDT thanks you for your comment. It is envisioned that engineering analysis may be used to supplement operational data or staged testing. The GVSDT does not believe that engineering analysis alone is sufficient. Attachment 1, Section 2 of the proposed standard states: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the capability shown on the associated D-Curve."** **And Note 2 in attachment 1 states:** **Note 2: "While not required by the standard, it is desirable to perform engineering analysis to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of applicable Facility capability that the Transmission Planner can use for modeling."**		

Organization	Yes or No	Question 10 Comment
TOP-002-2a, R13 is proposed for retirement by the RTOSDT (Project 2007-03).		
Tennessee Valley Authority GO	No	As the draft is currently written, these two methods are understood to be allowed. However, we believe a third alternative, engineering analysis, is needed in order for GOs to be able to verify generating unit reactive capabilities that are suitable for transmission system planning studies. It is proposed that Requirement R1.1 be re-written as follows: "Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with either Attachment 1 (staged testing or operational data) or by a new Attachment 3 (addressing engineering analysis)." Requirement R1.2 could then be qualified to be limited to reporting the results from staged testing or the use of operational data, and a new R1.3 could be inserted to require suitable reporting of the results from an engineering analysis. The time horizon of the two requirements in this standard are Long-Term Planning. MOD-025-2 does not have to focus solely upon operational testing to determine capabilities used for planning entity models. It is noted that TOP-002-2a R13 now requires the GOP to perform real and reactive capability testing at the request of the BA or TOP. The test can be specified if determined to be necessary by the BA or TOP.
Response: The GVSDT thanks you for your comment. It is envisioned that engineering analysis may be used to supplement operational data or staged testing. The GVSDT does not believe that engineering analysis alone is sufficient. Attachment 1, Section 2 of the proposed standard states: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the capability shown on the associated D-Curve."** **And Note 2 in attachment 1 states:** **Note 2: "While not required by the standard, it is desirable to perform engineering analysis to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of applicable Facility capability that the Transmission Planner can use for modeling."** **TOP-002-2a, R13 is proposed for retirement by the RTOSDT (Project 2007-03).**		
Associated Electric Cooperative, Inc.	No	As the draft is currently written, these two methods are understood to be allowed. However, we believe a third alternative, engineering analysis, is needed in order for GOs to be able to verify more appropriate generating unit reactive capabilities that are needed to ensure that planning entities have accurate generator data when assessing BES reliability. MOD-025-2 should not focus solely upon operational testing to

Organization	Yes or No	Question 10 Comment
		determine capabilities used for planning models, because experience has shown that testing does not provide appropriate reactive power capabilities. It is noted that TOP-002-2a R13 now requires the GOP to perform real and reactive capability testing at the request of the BA or TOP. The test can be specified if determined to be necessary by the BA or TOP.
Response: The GVSDT thanks you for your comment. It is envisioned that engineering analysis may be used to supplement operational data or staged testing. The GVSDT does not believe that engineering analysis alone is sufficient. Attachment 1, Section 2 of the proposed standard states: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the capability shown on the associated D-Curve."** **And Note 2 in attachment 1 states:** **Note 2: "While not required by the standard, it is desirable to perform engineering analysis to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of applicable Facility capability that the Transmission Planner can use for modeling."** **TOP-002-2a, R13 is proposed for retirement by the RTOSDT (Project 2007-03).**		
Duke Energy	No	As the draft is currently written, these two methods are understood to be allowed, but experience has shown may not be able to fully validate the available capabilities. We believe engineering analysis could be used in order for GOs to be able to verify generating unit reactive capabilities that are suitable for transmission system planning studies. The answer may be to test or operate as far as you can based on system voltage and then evaluate margin to unit thermal limits (Generator, Bus, GSUs, etc) and determine if you could reasonably have reached full capability if system conditions warranted the need.
Response: The GVSDT thanks you for your comment. It is envisioned that engineering analysis may be used to supplement operational data or staged testing. The GVSDT does not believe that engineering analysis alone is sufficient. Attachment 1, Section 2 of the proposed standard states: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the capability shown on the associated D-Curve."** **And Note 2 in attachment 1 states:** **Note 2: "While not required by the standard, it is desirable to perform engineering analysis to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of applicable Facility capability that the Transmission Planner can use for modeling."**		

Organization	Yes or No	Question 10 Comment
Ameren	No	While these two methods are acceptable, there is not enough flexibility included to allow for engineering support if necessary.
Response: The GVSDT thanks you for your comment. It is envisioned that engineering analysis may be used to supplement operational data or staged testing. The GVSDT does not believe that engineering analysis alone is sufficient. Attachment 1, Section 2 of the proposed standard states: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the capability shown on the associated D-Curve."** **And Note 2 in attachment 1 states:** **Note 2: "While not required by the standard, it is desirable to perform engineering analysis to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of applicable Facility capability that the Transmission Planner can use for modeling."**		
Indeck Energy Services	No	Engineering analysis should also be available
Response: The GVSDT thanks you for your comment. It is envisioned that engineering analysis may be used to supplement operational data or staged testing. The GVSDT does not believe that engineering analysis alone is sufficient. Attachment 1, Section 2 of the proposed standard states: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the capability shown on the associated D-Curve."** **And Note 2 in attachment 1 states:** **Note 2: "While not required by the standard, it is desirable to perform engineering analysis to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of applicable Facility capability that the Transmission Planner can use for modeling."**		
Pepco Holdings Inc Affiliates	Yes	"Staged" vs "operational" verification should be defined. In Attachment 1, are sections 2 and 5.2 consistent? That is should the % value be the same?

Organization	Yes or No	Question 10 Comment
Response: The GVSDT thanks you for your comment. A staged test is simply one that is scheduled for purposes of verification whereas an operational verification includes historical performance records. Section 2 was revised to, "At least 90 percent of a previously staged test that demonstrated at least 50 percent of the capability shown on the associated D-Curve". This makes Section 2 and 5.2 consistent. The percentage in Section 2 refers to the data that is acceptable to be used for verification for operational data where the percentage in 5.2 is the criterion for the level of change in a Facility capability that triggers the need to perform another verification. The GVSDT felt that the percentages chosen were appropriate for the intended purpose. The wording in Section 2 was revised to clarify intent.		
Cowlitz County PUD	Yes	Operational data will always be the preferred method of obtaining verification; however Cowlitz can't see how this would be possible for obtaining the reactive capabilities as prescribed. This will require costly and burdensome staged testing.
Response: The GVSDT thanks you for your comment. In order to obtain the data required by the standard, staged testing may be required. It is believed that staged testing can be scheduled at the required Load levels along with other plant operations (e.g. startup/shutdown, high Load, etc.) and since verification is required only once every five years (in most cases), the effort is not considered to be costly or burdensome.		
Ingleside Cogeneration LP	Yes	There is no reason to preclude the use of actual operations data in validation exercises.
Response: The GVSDT thanks you for your comment.		
Northeast Power Coordinating Council	Yes	
Imperial Irrigation District (IID)	Yes	
IRC Standards Review Committee (joint comments)	Yes	
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	
SPP Reliability Standards Development Team	Yes	

Organization	Yes or No	Question 10 Comment
SERC Planning Standards Subcommittee	Yes	
Idaho Power-Power Production	Yes	
PPL Generation	Yes	
Dominion	Yes	
FirstEnergy	Yes	
SERC Dynamics Review Sub-committee	Yes	
NERC Staff	Yes	
Arizona Public Service Company	Yes	
Westar Energy	Yes	
Public Service Enterprise Group	Yes	
Luminant Power	Yes	
Salt River Project	Yes	
PacifiCorp	Yes	
South Carolina Electric and Gas	Yes	
Dynegy Inc.	Yes	
New York Independent System	Yes	

Organization	Yes or No	Question 10 Comment
Operator		
Tri-State Generation and Transmission, In.	Yes	
Xcel Energy	Yes	
Exelon	Yes	
American Wind Energy Association	Yes	
Georgia Transmission Corporation	Yes	
Austin Energy	Yes	
Wisconsin Electric	Yes	
Great River Energy	Yes	
BC Hydro	Yes	
Northeast Utilities	Yes	
Constellation Power Generation	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	
American Electric Power	Yes	
Wisconsin Public Service Corp	Yes	

Organization	Yes or No	Question 10 Comment
ISO New England	Yes	
Lincoln Electric System		
CPS Energy	Yes	
Independent Electricity System Operator	Yes	
Gainesville Regional Utilities	Yes	
Oncor Electric Delivery Company LLC	Yes	
Indiana Municipal Power Agency	Yes	
Chelan County PUD	Yes	
APS		being intentionally left blank (no answer to be provided)
Tacoma Power	Yes	None
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Manitoba Hydro	Yes	

11. If operational data is utilized, the standard requires the verification be within 20 percent of the expected value. Do you agree with the 20 percent requirement? If not, please explain.

Summary Consideration: Many of the comments indicated that the proposed language in the standard on this point was confusing so the GVSDT has revised the language to better clarify intent. Several commenters indicated the 20percent tolerance value was too high, while others thought this value was too restrictive. The revised wording specifies the percentage selection criterion is applied to "the last reported capability." Attachment 1, Item 2 was revised to include:

Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as that operational data meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50percent of the capability shown on the associated D-Curve.

The GVSDT believes this change will alleviate commenter concerns. The GVSDT disagrees with commenters suggesting operational data restrictions should not be included.

Organization	Yes or No	Question 11 Comment
IRC Standards Review Committee (joint comments)	No	We have difficulty interpreting the 20% in Item 2 of Attachment 1, which says: "Operational data from within the year prior to the verification date is acceptable for the verification as long as IT (emphasis added) meets the criteria in 2.1 through 2.5 below and is within 20% of the expected value:" We interpret that the "IT" refers to the operational data. As such, we do not understand the "within 20% of the expected value". Does it mean the generator's real power output during the period from which operational data was collected must be within 20% of the generators' declared or name plate capability, or what? We need clarification, and suggest a revision to this Item 2 to provide the clarity. As written, we are unable to comment on the acceptability of the 20%.
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out**		

Organization	Yes or No	Question 11 Comment
of service), then the next verification shall be by another staged test, not operational data." **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability.**		
Pepco Holdings Inc Affiliates	No	20% "appears" to be a large variance. The DT should explain the justification for 20%. 5% or 10% would seem more reasonable, especially for large units.
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability.**		
SPP Reliability Standards Development Team	No	We feel that 20% is too great a buffer for this data and would suggest that the number reflect a buffer of 10% or less. We feel like having a buffer that is too high would cause entities to not use testing verification and would use the operational data verification. We also feel that this verification should be as accurate as possible to reflect the system in planning.
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability.**		
SERC Planning Standards Subcommittee	No	The 20 % requirement is too restrictive. Any operational data should be allowed to be used if it is accompanied by engineering analysis which calculates appropriate expected limits. This will be more useful to the Transmission Planner than a value from operational data within 20% which does not give the appropriate

Organization	Yes or No	Question 11 Comment
		expected limit.
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability.**		
Idaho Power-Power Production	No	What is the technical basis for the 20%? It seems high.
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability.**		
Santee Cooper	No	First of all "expected value" is not defined. Second any expected value based solely on nameplate data is subject to great variation based on the system the generator is connected to and should not be used to draw conclusions of satisfactory or unsatisfactory test results.
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last**		

Organization	Yes or No	Question 11 Comment
reported verified capability. The phrase, "expected value" is not used in the revised standard.		
PPL Generation	Yes	Note however that the expectation, as discussed above, is (for certain PPL Generation Registered Entities' units) derived from the aux bus limits, not the D-curve.
Response: The GVSDT thanks you for your comment.		
Dominion	No	If the question was meant to ask whether we agree with the sentence that reads" Operational data from within the year prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is within 20% of the expected value:" (Attachment 1, @2) then we respond affirmatively. However, we do not agree that a verification MUST be within 20%. It is possible that a physical change to either the asset being verified or the system it is interconnected with may result in its inability to perform to within 20%. If this is true, then we could agree that any such variance must be accompanied by an explanation as to why the verification did not fall with the 20% 'boundary'. There should be no requirement for percent of expected value.
Response: The GVSDT thanks you for your comment. You are correct with regard to the intent of the sentence. The intent of this standard is to verify the capability of a generator or synchronous condenser. A staged verification or operational data may be used for the verifications required by MOD-025. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **If a physical change occurs to an asset the verification should be based on the assets demonstrated capability with that change accounted for.**		
FirstEnergy	No	If the generating unit is capable of reaching 20% of the "expected value", than why should verification be concluded at that point? (We could potentially be missing out on fully realizing the potential of a reactive resource by pre-maturely ending the verification. A very important dimension of this verification (that was touched on in the Standard) is the recognition of equipment conditions or voltage regulator settings that could be improved when a staged test is performed. It is difficult if not impossible to capture equipment shortcomings or limitations which can be very useful to improving operations when verifying through the use of Operational data. Also, we need clarification regarding what would be considered "within 20% of expected value" if your leading reactive limit was 0 MVAR (unity)?
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to		

Organization	Yes or No	Question 11 Comment
state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90% of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability. This change is not intended to limit the scope of effort performed during a staged test. This change only establishes acceptance criteria for using operational data for verification in lieu of performing a staged test.**		
SERC Dynamics Review Sub-committee	No	The 20 % requirement is too restrictive. Any operational data should be allowed to be used if it is accompanied by engineering analysis which calculates appropriate expected limits. This will be more useful to the Transmission Planner than a value from operational data within 20% which does not give the appropriate expected limit.
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability. The intent of this statement is to allow an entity to use operational data in lieu of performing a staged test if the operational data is at least 90percent of the last reported verified capability.**		
NERC Staff	No	We agree the standard should provide flexibility to the Generator Owner; however, the need for flexibility must be balanced against the need for valid models for system studies. Accuracy must be at least as stringent as required for market dispatch. When operational data cannot be verified within 5% of the expected value, an entity should be required to provide data based on staged testing.
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-**		

Organization	Yes or No	Question 11 Comment
Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data." **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability. The operational data would always have been preceded by a staged test to demonstrate the unit/Facility capability. The allowance for operational data that is at least 90percent of a prior staged test with reasonable results will allow for a reduced burden on the GO or TO. The GVSDT disagrees that verification within 5percent of an expected value should require staged testing in this case because the expected value is mostly dependent on the system conditions at the time of the test rather than the unit's/facilities capabilities. If the unit/Facility cannot reach the revised criteria mentioned above, another staged test would then be required.**		
Public Service Enterprise Group	No	Attachment 1 is unclear as to the implementation of the 20% requirement. Paragraph 2 states "Operational data from within the year prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is within 20% of the expected value:" As written, it appears that the 20% only applies to operational data "within the year prior to the verification date." Does the 20% apply also to staged tests? If not, why not? Paragraph 5.2 in Attachment 1, regarding operational tests, is also relevant: "If data for different points is recorded on different days, the Generator Owner shall designate one of the dates as the verification date, and report that date as the verification date on MOD-025- Attachment 2 for periodicity purposes." Is the SDT proposing to comingle operational data from one-year prior to the verification date as long as it is within 20% of the expected value? If so, what value would be reported - the test data that may be up to 20% higher or lower than the expected value or the expected value?
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability.**		
SERC Generation sub-committee	No	Since the "expected value" is not clearly identified, it is not possible to determine if 20% is an appropriate value. Furthermore, if the "expected value" is the "D-curve" for lagging Vars, we believe this is not a realistic expectation since operational data for most generating units does not approach 80% of the "D curve" value in

Organization	Yes or No	Question 11 Comment
		normal operating conditions (or even in staged testing based on our experience). A recent survey of the SERC region has shown that only 34% of 85 generators surveyed performing staged Q production tests could reach 80% of their D curve lagging Q capability. The same survey showed that only 19% of 32 generators surveyed performing staged Q absorption tests could reach 80% of their under excitation limit (UEL) characteristic setting. Therefore, the "within 20% of the expected value" requirement should be deleted. If an engineering analysis (which uses operational data for analytical model confirmation) is allowed as an alternative verification method, the 20% tolerance given above is not needed. Reference comment 2 under Question 14 for additional discussion on the verification methods.Any operational data should be allowed if accompanied by engineering analysis that calculates appropriate expected limits. This will be more useful to the Transmission Planner than a value from operational data within 20% which does not give the appropriate expected limit.
Response: The GVSDT thanks you for your comment. The phrase, "expected value" is not used in the revised standard. **Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state:** **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability.**		
Arizona Public Service Company	No	If by expected, it means maximum/minimum, then no. In many operating conditions, one does not get within 20% of the maximum/minimum. Need to be clear about what expected means.
Response: The GVSDT thanks you for your comment. The phrase, "expected value" is not used in the revised standard. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability.**		

Organization	Yes or No	Question 11 Comment
Southern Company	No	The "expected value" is not clearly identified, so it is not possible to determine if 20% of this value is appropriate. Furthermore, if the "expected value" is the D curve for lagging Vars, we believe this is not a realistic expectation because operational data for most generating units does not approach 80% of the D curve value in normal operating conditions or even in staged testing based on our experience. A recent survey of the SERC region has shown that only 34% of 85 generators surveyed performing staged Q production tests could reach 80% of their D curve lagging Q capability. The same survey showed that only 19% of 32 generators surveyed performing staged Q absorption tests could reach 80% of their underexcitation limit (UEL) characteristic setting. Therefore, the "within 20% of the expected value" requirement should be deleted. If an engineering analysis (which uses operational data for analytical model confirmation) is allowed to be an alternative method for verifying the unit capability, the 20% tolerance given above is not needed. See our Comment 2 under Question 14 for additional discussion on the verification methods.
Response: The GVSDT thanks you for your comment. The phrase, "expected value" is not used in the revised standard. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability.**		
Tennessee Valley Authority GO	No	Since the "expected value" is not clearly identified, it is not possible to determine if 20% is an appropriate value. Furthermore, if the "expected value" is the "D curve" for lagging Vars, we believe this is not a realistic expectation since operational data for most generating units does not approach 80% of the "D curve" value in normal operating conditions (or even in staged testing based on our experience). A recent survey of the SERC region has shown that only 34% of 85 generators surveyed performing staged Q production tests could reach 80% of their D curve lagging Q capability. The same survey showed that only 19% of 32 generators surveyed performing staged Q absorption tests could reach 80% of their underexcitation limit (UEL) characteristic setting. Therefore, the "within 20% of the expected value" requirement should be deleted. If an engineering analysis (which uses operational data for analytical model confirmation) is allowed as an alternative verification method, the 20% tolerance given above is not needed.Any operational data should be allowed if accompanied by engineering analysis that calculates appropriate expected limits. This will be more useful to the Transmission Planner than a value from operational data within 20% which does not

Organization	Yes or No	Question 11 Comment
		give the appropriate expected limit.
Response: The GVSDT thanks you for your comment. The phrase, "expected value" is not used in the revised standard. Based on comments and further review the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability.**		
South Carolina Electric and Gas	No	The 20 % requirement is too restrictive. Any operational data should be allowed to be used if it is accompanied by engineering analysis which calculates appropriate expected limits.
Response: The GVSDT thanks you for your comment. The GVSDT does not agree that "any" operational data is appropriate to be used as the basis for engineering analysis.		
Associated Electric Cooperative, Inc.	No	Since the "expected value" is not clearly identified, it is not possible to determine if 20% is an appropriate value. Furthermore, if the "expected value" is the "D curve" for lagging Vars, we believe this is not a realistic expectation since operational data for most generating units does not approach 80% of the "D curve" value in normal operating conditions (or even in staged testing based on our experience). A recent survey of the SERC region has shown that only 34% of 85 generators surveyed performing staged Q production tests could reach 80% of their D curve lagging Q capability. The same survey showed that only 19% of 32 generators surveyed performing staged Q absorption tests could reach 80% of their underexcitation limit (UEL) characteristic setting. Therefore, the "within 20% of the expected value" requirement should be deleted. If an engineering analysis (which uses operational data for analytical model confirmation) is allowed as an alternative verification method, the 20% tolerance given above is not needed.
Response: The GVSDT thanks you for your comment. The phrase, "expected value" is not used in the revised standard. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."**		

Organization	Yes or No	Question 11 Comment
The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability.		
New York Independent System Operator	No	What determines the expected value to be within 20% of?
Response: The GVSDT thanks you for your comment. The phrase, "expected value" is not used in the revised standard. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability.**		
Ameren	No	While the 20% margin is appropriate and appreciated, it is unclear if verifying the output of a generator at 80% of real rated output will satisfy regulator rating requirements at the time of seasonal peak. Thus, from the user of this data (e.g. planners), this % is too great. From the generator owner and testing personnel , this % makes sense and seems appropriate. We would suggest the SDT provide basis for this % and a guidance how it should be used for all conditions.
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability. The GVSDT has added a note to Attachment 1 to allow for and encourage engineering analysis to provide a more reasonable estimate of unit capabilities in cases where system conditions will not allow the unit to demonstrate its full capability. The GVSDT does not believe that engineering analysis alone is sufficient and therefore testing is still required to show that limitations do not exist that would not be identified with engineering analysis such as a thermally sensitive field or an inaccurate limiter in the voltage regulator.** **Note 2: While not required by the standard, it is desirable to perform engineering analysis to determine expected applicable Facility capabilities**		

Organization	Yes or No	Question 11 Comment
under less restrictive system voltages than those encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of applicable Facility capability that the Transmission Planner can use for modeling.		
Indeck Energy Services	No	The point is that the rating should be changed to the value tested. If a unit can't reach it, it's not a rating.
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability. The proposed standard allows engineering analysis to obtain the best possible results for use in modeling.**		
Oncor Electric Delivery Company LLC	No	Any operational varation from expected should be explained by the Generator Owner and a solution to provide full capability be presented.
Response: The GVSDT thanks you for your comment. This change only establishes acceptance criteria for using operational data for verification in lieu of performing a staged test. The reason for the variation must be included in the remarks section of Attachment #2 if a limitation is reached during verification testing.		
Georgia Transmission Corporation	No	The data should be accepted as is unless the data is meaningless.
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability.**		

Organization	Yes or No	Question 11 Comment
Austin Energy	No	This requires a guarantee to an expected performance that may be impacted by a particular operational problem during the test (high cooling water or ambient temperatures, etc). The test results should be accepted as is and logged as the new generator capability until such time as it is retested later with better results.
Response: The GVSDT thanks you for your comment. The phrase, "expected value" is not used in the revised standard. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability. The reason for a variation must be included in the remarks section of Attachment #2 if a limitation is reached during verification testing.**		
BC Hydro	No	Such a wide margin seems to defeat the purpose of verifications. If such margin is technically acceptable to planners, the question is why even requiring verifications, especially for smaller units. It is hard to immagine that actual capability (active or reactive) of generating units/facilities would ever be lower than 80% of declared.
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability.**		
American Electric Power	No	System conditions greatly affect the expected reactive power values as stated in Attachment 1, Notes 1 and 2. While 20% appears reasonable for the real power verification, there needs to be flexibility as to this value for reactive power, given that system conditions are not constant.

Organization	Yes or No	Question 11 Comment
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability. Please note this statement specifies the acceptance criteria required for performing verification using operational data. If acceptable operational data cannot be obtained, then staged testing is required.**		
Ingleside Cogeneration LP	No	The real and reactive capacities should be validated to be within 20% of expectation at the limits identified in the Transmission Operator's reactive capability schedule, not the generator's operational limits.
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability. The SDT disagrees that the verification should be against the TOP's reactive capability schedule since the data collected is for use in long-term planning studies, not for Real-time operations.**		
ISO New England	No	As we interpret the language, we do not agree with the 20% requirement. In the assessments performed in our area our goal is to use data that is much more accurate than what appears to be required under the standard. Allowing verification to be up to 20% inaccurate may result in inaccurate system assessments, potentially leading to overlooking potential system problems or to unnecessary system investment to address system concerns which are not really present. This value should be changed to a maximum of 5%.
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-**		

Organization	Yes or No	Question 11 Comment
Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data." **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability. The operational data would always have been preceded by a staged test to demonstrate the unit/Facility capability. The allowance for operational data that is at least 90percent of a prior staged test with reasonable results will allow for a reduced burden on the GO or TO. The GVSDT disagrees that verification within 5percent of an expected value should require staged testing in this case because the expected value is mostly dependent on the system conditions at the time of the test, rather than the unit's/Facilities capabilities. If the unit/Facility cannot reach the revised criteria mentioned above, another staged test would then be required.**		
Duke Energy	No	We have model validation requirements but no definitions to what we are needing to validate to. The "expected value" is not clearly defined, so it is not possible to determine if 20% of this value is appropriate. Furthermore, if the "expected value" is the "D curve" for lagging Vars, we believe this is not a realistic expectation since operational data for most generating units does not approach 80% of the "D curve" value in normal operating conditions (or even in staged testing based on our experience). A recent survey of the SERC region has shown that only 34% of 85 generators surveyed performing staged Q production tests could reach 80% of their D curve lagging Q capability. The same survey showed that only 19% of 32 generators surveyed performing staged Q absorption tests could reach 80% of their underexcitation limit (UEL) characteristic setting. Therefore, the "within 20% of the expected value" requirement should be deleted. If an engineering analysis (which uses operational data for analytical model confirmation) is allowed as an alternative verification method, the 20% tolerance given above is not needed. Reference our response to Question #10.
Response: The GVSDT thanks you for your comment. The phrase, "expected value" is not used in the revised standard. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability. Please note this statement specifies operational data acceptance criterion and does not apply to staged testing.**		
Lincoln Electric System	No	The definition of "expected value" needs to be more clearly defined as it is somewhat unclear. The verification should probably be within at least 5percent of the expected output of the generating unit for a given ambient temperature, rather than 20% as stated in this draft. For a simple-cycle gas turbine the real

Organization	Yes or No	Question 11 Comment
		power output for the verification test would in most cases be greater than what it would be for summer peak conditions due to the higher generator output that typically occurs with these units as the turbine inlet temperature decreases. It is usually desirable to test the unit with the same conditions that the unit will be most needed. For summer peaking utilities this would be with reasonably high ambient conditions. When only recording real power data it is usually not that difficult to recordthe data in the summer when the units are already operating to serve the load. The coordination to record reactive power data at this time may be more difficult.
Response: The GVSDT thanks you for your comment. The phrase, "expected value" is not used in the revised standard. Based on comments and further review the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability. The proposed standard allows the use of operational data as an option when verifying units. If acceptable operational data cannot be obtained, then staged testing is required.**		
Independent Electricity System Operator	No	We have difficulty interpreting the 20% in Item 2 of Attachment 1, which says: "Operational data from within the year prior to the verification date is acceptable for the verification as long as IT (emphasis added) meets the criteria in 2.1 through 2.5 below and is within 20% of the expected value:"We interpret that the "IT" refers to the operational data. As such, we do not understand the "within 20% of the expected value". Does it mean the generator's real power output during the period from which operational data was collected must be within 20% of the generator's declared or name plate capability, or what? We need clarification, and suggest a revision to this Item 2 to provide the clarity.As written, we are unable to comment on the acceptability of the 20%.
Response: The GVSDT thanks you for your comment. The phrase, "expected value" is not used in the revised standard. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last**		

Organization	Yes or No	Question 11 Comment
reported verified capability.		
percentpercentpercent		
Chelan County PUD		For hydro, 20% of min and max reactive may be difficult to achieve. Salient pole machines have much greater lattitude than thermal, but system and bus conditions dictate if it is possible. Allowance should be made for realities in these cases. Again, what will dictate - voltage schedule or testing requirements?
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability. The reason for the variation must be included in the remarks section of Attachment #2 if a limitation is reached during verification testing.**		
Westar Energy	Yes	
Luminant Power	Yes	
Northeast Power Coordinating Council	Yes	
Imperial Irrigation District (IID)	Yes	
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	
Salt River Project	Yes	

Organization	Yes or No	Question 11 Comment
PacifiCorp	Yes	
Dynegy Inc.	Yes	
Tri-State Generation and Transmission, In.	Yes	
Cowlitz County PUD	Yes	
Xcel Energy	Yes	
Exelon	Yes	
American Wind Energy Association	Yes	
Tacoma Power	Yes	None
Wisconsin Electric	Yes	
Great River Energy	Yes	
Northeast Utilities	Yes	
Constellation Power Generation	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	
Manitoba Hydro	Yes	
Gainesville Regional Utilities	Yes	What is defined as the "expected value?"

Organization	Yes or No	Question 11 Comment
Indiana Municipal Power Agency	Yes	
Wisconsin Public Service Corp		No comment.
APS		being intentionally left blank (no answer to be provided)
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Response: The GVSDT thanks you for your comment.		

12. Are you aware of any regional variances that would be required for this standard?

Summary Consideration: Commenters have identified regional variances currently in effect, as required by MOD-024 and MOD-025. It is anticipated that these regional standards will be retired once MOD-025-2 is approved. Language provided by Relaibility*First* staff has been added to the Implementation plan concerning the Reliability*First* standards:

"It is the intent of Reliability*First* to perform a review of both the MOD-024-RFC-01 and MOD-025-RFC-01 standards upon NERC Board of Trustees approval of the associated NERC MOD-025-2 standard. The purpose of the review would be to ensure that any duplicative requirements or any requirements which are less restrictive or do not add additional detail will be considered for retirement. The steps outlined in the Reliability*First* Reliability Standards Development Procedure will be followed for any such revisions or retirements."

Organization	Yes or No	Question 12 Comment
SPP Reliability Standards Development Team	Yes	If the testing time is 1 hour as written then we have a variance of the SPP criteria of 15 minutes, but if the team decides to change that time limit then we wouldn't and our answer would change to no.
Response: The GVSDT thanks you for your comment. The reliability goal of the one-hour verification period is to ensure that generator temperature is stable and the verification demonstrates a sustainable capability. The GVSDT believes one hour is sufficient for the generator to reach thermal stability during testing for confirming the reliability objective of this standard. If MOD-025-2 is approved as proposed, then the SPP regional criteria will need to be revised. The continent-wide standard takes precedence over regional criteria. When this standard is approved, members of SPP will need to comply with the continent-wide standard. SPP could request a regional variance if SPP has technical justification to support the need for a 15-minute test period that is based on a physical difference in the bulk power system.		
Westar Energy	Yes	The SPP Criteria requires that the testing period should be 15 minutes rather than the 1 hour listed in the standard.
Response: The GVSDT thanks you for your comment. The reliability goal of the one-hour verification period is to ensure that generator temperature is stable and the verification demonstrates a sustainable capability. The GVSDT believes one hour is sufficient for the generator to reach thermal stability during testing for confirming the reliability objective of this standard. If MOD-025-2 is approved as proposed, then the SPP regional standard will need to be revised. The continent-wide standard takes precedence over regional criteria. When this standard is approved, members of SPP will need to comply with the continent-wide standard. SPP could request a regional variance if SPP has technical justification to support the need for a 15-minute test period that is based on a physical difference in the bulk power system.		

Organization	Yes or No	Question 12 Comment
Indeck Energy Services	Yes	The temperature adjustment probably varies by region. There is no basis in the ROP for members on one region to vote on requirements for another region. There are nationwide standards or regional standards. The SDT can't have it both ways.
Response: The GVSDT thanks you for your comment. Within a continent-wide standard, a requirement can include alternative performance based on different Facility characteristics, different regions, or different interconnections. (See INT-006-3 for an example.)		
Oncor Electric Delivery Company LLC	Yes	Oncor also recommends that consideration be given to a regional variance in that the information required of the Generator Owner as specified in R1 should be provided to the Planning Authority in the ERCOT region and not the Transmission Planner. This would align with current protocols, operating guide and planning guide as it relates to resource testing.
Response: The GVSDT thanks you for your comment. Oncor could sponsor a regional variance if its Region has technical justification to support the need for a variance based on a physical difference in the BES.		
Exelon	Yes	It is strongly suggested that the SDT review each existing Generator Real and Reactive Power Capability Regional Standard (or other guidance) currently in place for best practices and potential conflicts. As stated in responses to questions 5, 7, 13, and 14 nuclear units do not perform under-excited (leading) reactive capability testing due to concerns with unit stability and potential under voltage conditions on internal nuclear plant safety buses that may challenge safe plant operations and could lead to a plant transient or shutdown in accordance with NRC operating license. Exelon Nuclear is a member of and has 17 nuclear units in two Regions (ReliabilityFirst and SERC). RFC Regional Standard MOD-025-RFC-01, "Verification and Data Reporting of Generator Gross and Net Reactive Power Capability," currently has a specific exclusion that "Under-excited (leading) Reactive Power capability verification is not required of nuclear units." SERC Regional Criteria, "Verification of Generator Real and Reactive Power Capability," has the following statement regarding nuclear units, " (t)he capabilities of nuclear units will be determined taking into consideration the fuel management program of the unit and any restrictions imposed by regulatory agencies.
Response: The GVSDT thanks you for your comment. RFC has informed the GVSDT that: **It is the intent of Reliability*First* to perform a review of both the MOD-024-RFC-01 and MOD-025-RFC-01 standards once the NERC Board of Trustees approves the NERC MOD-025-2 standard. The purpose of this review is to ensure redundant and less restrictive requirements are either revised or considered for retirement from the RFC standards in accordance with the Reliability*First* Reliability Standards Development Procedure.** **Nuclear units are not required to perform Reactive Power verification at minimum Real Power output.**		

Organization	Yes or No	Question 12 Comment
Ingleside Cogeneration LP	Yes	TRE, WECC, and SERC have similar but slightly different requirements. It is Ingleside's expectation that these regions would align their processes to MOD-025-2 when it takes effect.
Response: The GVSDT thanks you for your comment.		
Duke Energy	Yes	There have historically been regional differences in unit criticality size.
Response: The GVSDT thanks you for your comment.		
Luminant Power	Yes	
New York Independent System Operator	No	In the NPCC region Directory 9 and 10 were written to meet the original obligations of MOD-024 and MOD-025. These directories are more specific or more stringent than MOD-025-2.
Response: The GVSDT thanks you for your comment. The original MOD-024 and MOD-025 standards required entities to do verification as directed by the regional entities. In response to a FERC directive, the revised standard now specifies requirements that apply to all entities as a continent-wide standard. If a region determines a technical variation is required, then the region can propose a variance in accordance with the Standard Processes Manual. FERC has indicated that it will generally accept regional variances that address performance not addressed in a continent-wide standard, and technically-justified performance that is more stringent than the performance in the continent-wide standard.		
American Electric Power	No	With respect to reactive power, AEP is not aware of any regional variances that would be required for this standard.
Response: The GVSDT thanks you for your comment.		
Northeast Power Coordinating Council	No	
Imperial Irrigation District (IID)	No	
IRC Standards Review Committee (joint comments)	No	
Midwest Reliability Organization's	No	

Organization	Yes or No	Question 12 Comment
NERC Standards Review Forum (NSRF)		
SERC Planning Standards Subcommittee	No	
Idaho Power-Power Production	No	
PPL Generation	No	
Dominion	No	
FirstEnergy	No	
SERC Dynamics Review Sub-committee	No	
NERC Staff	No	
Public Service Enterprise Group	No	
SERC Generation sub-committee	No	
Arizona Public Service Company	No	
Southern Company	No	
Tennessee Valley Authority GO	No	
Salt River Project	No	
PacifiCorp	No	
South Carolina Electric and Gas	No	

Organization	Yes or No	Question 12 Comment
Associated Electric Cooperative, Inc.	No	
Dynegy Inc.	No	
Tri-State Generation and Transmission, In.	No	
Cowlitz County PUD	No	
Xcel Energy	No	
American Wind Energy Association	No	
Tacoma Power	No	None
Georgia Transmission Corporation	No	
Austin Energy	No	
Wisconsin Electric	No	
Great River Energy	No	
BC Hydro	No	
Northeast Utilities	No	
Constellation Power Generation	No	
Consolidated Edison Co. of NY,	No	

Organization	Yes or No	Question 12 Comment
Inc.		
Wisconsin Public Service Corp	No	
ISO New England	No	
Manitoba Hydro	No	
Independent Electricity System Operator	No	
Gainesville Regional Utilities	No	
Ameren	No	
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
APS		being intentionally left blank (no answer to be provided)

13. Are you aware of any conflicts between the proposed standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement?

Summary Consideration: Major conflicts were not reported between the proposed standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement.

Organization	Yes or No	Question 13 Comment
PPL Generation	Yes	Ref. the inputs made above, there should be just one VAR test, with a single set of results going to all parties.
Response: The GVSDT thanks you for your comment. The standard requires the GO and TO to provide the information to the TP. As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the operations planning and Real-time operations time horizons. Per the NERC Reliability Functional Model (V5, Page 25), the Transmission Planner has the following relationships with other entities : **2. Collects information including:** **c. Generator unit performance characteristics and capabilities from Generator Owners.** **5. Coordinates the evaluation of BES expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.** **6. Reports on and coordinates its BES expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers.**		
FirstEnergy	Yes	Regional Entities such as RFC currently have Real and Reactive standards in place for its members and will need to evaluate the need to keep their standard or revise it to remove any inconsistencies that may exist. One inconsistency is the periodicity of verification for real power.
Response: The GVSDT thanks you for your comment. RFC has informed the GVSDT that: **It is the intent of Reliability*First* to perform a review of both the MOD-024-RFC-01 and MOD-025-RFC-01 standards once the NERC Board of Trustees approves the NERC MOD-025-2 standard. The purpose of this review is to ensure redundant and less restrictive requirements are either revised or**		

Organization	Yes or No	Question 13 Comment
considered for retirement from the RFC standards in accordance with the Reliability First Reliability Standards Development Procedure.		
Exelon	Yes	Nuclear units do not perform under-excited (leading) reactive capability testing due to concerns with unit stability and potential under voltage conditions on internal nuclear plant safety buses that may challenge safe plant operations and could lead to a plant transient or shutdown in accordance with NRC operating license. Performance of reactive capability tests cannot challenge nuclear plant NRC licensee Technical Specification voltage limit requirements.
Response: The GVSDT thanks you for your comment. Item 2.2 in Attachment 1 states: "Verify Reactive Power of all generating units, other than wind and photovoltaic, for maximum over-excited (lagging) and under-excited (leading) Reactive capability at the minimum Real Power output at which they are normally expected to operate. Nuclear units are not required to perform Reactive Power verification at minimum Real Power output."		
Ameren	Yes	There may be a conflict with MISO Module E as it relates to duration of the testing, e.g. one hour versus longer than hour duration.
Response: The GVSDT thanks you for your comment. If the MISO duration is longer, then there will not be any issue with meeting the one-hour requirement in MOD-025.		
Oncor Electric Delivery Company LLC	Yes	In the ERCOT Region, resource testing and most all communications regarding unit performance is facilitated by the Independent System Operator who is the Planning Authority. This is consistent with current, ERCOT protocols, operating guide and planning guide.
Response: The GVSDT thanks you for your comment. MOD-025 requires the GO to provide information to the Transmission Planner. As envisioned, if the Planning Coordinator (Authority) needs the information provided, the Transmission Planner will provide per the relationships in the functional model.		
Austin Energy	Yes	See the response to Question 6.
Manitoba Hydro	Yes	A number of Canadian Entities have the BES defined within their provincial legislation. This may introduce differences between the elements that are included in the BES (and elements that are therefore applicable to this standard) according to provincial legislation and the NERC definition. As well, since Canadian Entities are not under FERC jurisdiction, the effective date of this standard may differ for Canadian entities and entities under FERC jurisdiction.
Response: The GVSDT thanks you for your comment. Entities are responsible for verifying only those units applicable under the Facilities section of		

Organization	Yes or No	Question 13 Comment
this standard. The GVSDT is aware that Canadian entities may have a different Implementation plan since they are not FERC jurisdictional.		
Chelan County PUD		Voltage schedule requirements may conflict.
Response: The GVSDT thanks you for your comment. The GVSDT cannot respond fully to this comment without more information.		
Idaho Power-Power Production	No	No conflict, but as stated before, it seems to be redundant with FAC-008, FAC-009 and the existing WECC validation policy.
Response: The GVSDT thanks you for your comment. Please see response to earlier comment.		
American Electric Power	No	AEP is not aware of any conflicts between the proposed standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement.
Response: The GVSDT thanks you for your comment.		
ISO New England	No	The obligations set by this Standard are less stringent for Generator Owners/Operators than those contained in ISO-NE's Tariff. In addition, FERC's Standard Generation Interconnection Rules make clear that material changes to generation facilities (which would include changes to reactive power capabilities) must be reported to the Transmission Service Provider prior to the change being made. The Standard Drafting Team should consider whether language is appropriate to make clear that the Standard is not meant to displace obligations to report reactive power capabilities already contained in Transmission Service Providers' tariffs.
Response: The GVSDT thanks you for your comment. The standard is designed to be a verification of capability for long-term planning studies and have no interaction with any tariffs.		
Northeast Power Coordinating Council	No	
Imperial Irrigation District (IID)	No	
IRC Standards Review Committee (joint comments)	No	

Organization	Yes or No	Question 13 Comment
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	No	
SPP Reliability Standards Development Team	No	
SERC Planning Standards Subcommittee	No	
Dominion	No	
SERC Dynamics Review Sub-committee	No	
NERC Staff	No	
SERC Generation sub-committee	No	
Arizona Public Service Company	No	
Westar Energy	No	
Southern Company	No	
Tennessee Valley Authority GO	No	
Luminant Power	No	
Salt River Project	No	
PacifiCorp	No	

Organization	Yes or No	Question 13 Comment
South Carolina Electric and Gas	No	
Associated Electric Cooperative, Inc.	No	
Dynegy Inc.	No	
New York Independent System Operator	No	
Tri-State Generation and Transmission, In.	No	
Cowlitz County PUD	No	
Xcel Energy	No	
American Wind Energy Association	No	
Tacoma Power	No	None
Georgia Transmission Corporation	No	
Wisconsin Electric	No	
Great River Energy	No	
BC Hydro	No	
Northeast Utilities	No	

Organization	Yes or No	Question 13 Comment
Constellation Power Generation	No	
Consolidated Edison Co. of NY, Inc.	No	
Ingleside Cogeneration LP	No	
Wisconsin Public Service Corp	No	
GE Energy	No	
Duke Energy	No	
Independent Electricity System Operator	No	
Gainesville Regional Utilities	No	
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
APS		being intentionally left blank (no answer to be provided)
Response: The GVSDT thanks you for your comment.		

14. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please provide a reference to the section, requirement, or subrequirement that you believe should be changed, added ,or deleted and the rationale for your proposal.

Summary Consideration: A number of commenters suggested revisions for clarity that were accepted by the GVSDT. Minor changes were made to the standard to incorporate many of those suggestions. Language was added to recommend that the AVR be in automatic control while conducting reactive capability testing, but that Reactive capability testing must be done even if the AVR is not available.

The following language was also added to allow flexibility if 90percent of the generation is not available when testing wind turbines or photovoltaic inverters.

If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, the Generator Owner must document the reasons it was unable to meet the threshold and test to the full capability at the time of the test. The Generator Owner shall retest the Facility within six months of being able to reach the 90 percent threshold. percent

Organization	Yes or No	Question 14 Comment
Associated Electric Cooperative, Inc.	Yes	1) We agree with the stated purpose of this standard however we don't believe that this standard, as written, meets the intent related to reactive capabilities. We have already spent significant time, effort and money to perform reactive capability testing, and the test results provide little value toward establishing appropriate capabilities for planning purposes. Additionally, this testing puts our equipment and the BES at risk. It appears that this standard will make us repeat this effort with additional requirements for reactive capability testing at Pmin. 2) This requirement will require units that normally do not run or have a very low capacity factor to be verified. Please add a provision for excluding these requirements for units that do not regularly run, similar to other NERC standard exemption requirements. 3) The standard needs to allow the inclusion of engineering analysis to supplement or replace testing when appropriate (see comments to question #10). 4) Instead of the periodic requirements, there needs to be a change based validation requirement. If a plant is materially changed (such as significant equipment changes or performance degradation), there needs to be a new validation done. 5) In R1.2 and R2.2, the phrase "same information" is used, while in M1 and M2 the phrase "equivalent

Organization	Yes or No	Question 14 Comment
		information" is used - we suggest changing R1.2 and R2.2. to match the M1 and M2. 6) Specifying Normal Operating H2 pressure in Attachment 1, section 2.5 may not produce the desired maximum Q cap results - consider changing "normal operating " to "maximum sustainable (within design limits)" 7) In Attachment 1, section 2.2, we suggest changing "they could normally be expected to operate" to "they are normally expected to operate". 8) We suggest revising Requirements R1.3 and R2.3 to read: "Submit the capability information to its TP within 90 calendar days of completion of the verification." to clarify these requirements and to make them consistent. We also believe 90 days will create an undue hardship for GOs who own a large number of generators and believe this requirement should allow for additional time when authorized by the TP or PC. 9) The first paragraph of the Compliance Data Retention Section D 1.2 is difficult to understand. Please simplify using multiple sentences, if possible. 10) In the VSL table for R1 and R2, we suggest changing the phrasing "from the date the data was recorded" to "from the verification date" each time it is used (7 times). 11) In the VSL table for R1, both the first and fourth items are not needed in the list of the four items which make up the OR statement. It is sufficient to measure if the data is more than 30 days late to be categorized as Severe. 12) In the VSL table for R2, we suggest replacing the second item in the list of the two items which make up the OR statement to match the corresponding item in R1 relative to the tardiness of the submission to the TP greater than 30 days late (> 120 days total). 13) Revise attachment 1 section 5.1 and 5.2 to change “last more than 6 months” to “last more than 1 year,” to align with the typical long-term planning horizon. 14) Note that the standard is only applicable to the GO/GOP, but needs involvement from the TO/TP/TOP to adequately complete a validation. Thus the standard needs to address the responsibilities of those entities for it to adequately address the issue of model validation. It is noted that MOD-11which is supposed to clarify modeling data requirements has not yet been completed and approved. Yet MOD-25 is requiring verification of this data. It is also recognized that generator verification methods are producing results that are not being directly used in the models (due to various operating or system limitations). As a result, it is not clear that MOD-025 is achieving the reliability purpose intended. 15) This standard establishes a periodic generator testing regime which, when implemented on a large number if generators, creates a continuous state of testing across the BES. We question if this approach

Organization	Yes or No	Question 14 Comment
		really improves the reliability of the BES. The use of normal operational data, supplemented by analysis, represents a better approach for most generators.

Response: The GVSDT thanks you for your comment.

(1) Response: Since system conditions can be a limiting factor, no test can assure that the rated values of the excitation equipment and generator will be reached during a test. The GVSDT believes that testing as close as possible to the Pmax and Qmax point will identify most issues with equipment, and the reliability purpose will be achieved. Through Order 693, the FERC has required testing at other points in order to help define the entire performance curve for the unit. This data verification is a result of a FERC directive in paragraph 1321 which states:

1321. We disagree with commenters that verifying generator reactive capability is a particularly difficult issue. The capability of generators to produce reactive power is essential for Real-time analysis and planning. The Reliability Standard addressing this issue requires a generator to verify reactive capability only at the unit's full MW Loading. However, other than baseLoad units, most generating units rarely operate at full MW Loading. It is unclear what reactive capability is available throughout a unit's Real Power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit's Real Power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary. Therefore, we adjust the proposal in the NOPR and direct the ERO to modify MOD-025-1 to require verification of reactive power capability at multiple points over a unit's operating range.

(2) Response: The standard only requires testing once every 5 years. Operating a low capacity factor unit for 1 hour every five years should not be a burden.

(3) Response: Engineering analysis is allowed to supplement operating data as specified in Note 2 of Attachment 1.

(4) Response: The GVSDT agrees that material changes should require verification, and the standard calls for this specifically in item 2 of Attachment 1, "Periodicity for conducting a new verification". The GVSDT further believes that even if changes do not occur, verification is performed at least every five years to assure that equipment can still reliably function.

(5) **Response: The GVSDT agrees and has modified the standard to use the same wording in both the measures and requirements.**

(6) **Response: The intent is to capture the normal operating condition and not to increase hydrogen pressure or make other alteration just for testing.**

(7) **Response: The GVSDT has changed the standard to clarify this point. The phrase, "could normally be expected" was changed to "are normally expected."**

(8) **Response: The GVSDT believes that 90 days provides sufficient time and is not a hardship.**

(9) **Response: This is standard language. The GVSDT believes language is clear.**

(10) **Response: The GVSDT has modified the standard's VSLs for clarity by changing "date data was recorded" to "date of verification".**

Organization	Yes or No	Question 14 Comment
(11 **Response: The GVSDT believes that all the items in the "or" statement are needed to characterize a possible severe violation level. VSLs should identify a wide range of possible noncompliance.** (12) **Response: The GVSDT believes that all the items in the "or" statement are needed to characterize a possible severe violation level.** (13) **Response: The GVSDT believes that the 6 month time frame specified is appropriate.** (14) **Response: Since system conditions can be a limiting factor, no test can assure that the rated values of the excitation equipment and generator will be reached during a test. The GVSDT believes that testing as close as possible to the Pmax and Qmax point will identify most issues with equipment, and the reliability purpose will be achieved. Through Order 693, the FERC has required testing at other points in order to help define the entire performance curve for the unit. Please advise if the commenter has specific suggestions on how to better achieve this reliability purpose. Note that the intent of MOD-025 is to verify the accuracy of specific data used in long-range planning, not Real-time operations. While MOD-011 was not approved by FERC, it is effective in some Canadian Provinces and in the United States, FERC advised that entities "should" comply with MOD-011. (From Order 693: In the interim, compliance with MOD-011-0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.)** (15) **Response: Normal operational data is allowed by the standard.**		
SERC Generation sub-committee	Yes	1) This requirement will require units that normally do not run or have a very low capacity factor to be verified. Please add a provision for excluding these requirements for units that do not regularly run, similar to other NERC standard exemption requirements. 2) The standard needs to allow the inclusion of engineering analysis (with operational data) to supplement or replace testing when appropriate (see comments to question #10). It is noteworthy that the original NERC Board Approved version of this standard states in requirement R1.3 that acceptable methods for reactive capability verification "include use of commissioning data, performance tracking, engineering analysis, testing, etc." This represents the "allowance to use of all the tools in the toolbox" approach which is appropriate when no single tool is sufficient to accomplish the stated reliability objectives, consistent with the FERC Acceptance Criteria of a Reliability Standard (reference Paragraphs 321, 324, 328, 332). This approach is reflected in the SERC regional procedure for MOD-025-1 which was developed by a joint transmission-generation task force. 3) The 5 year test interval should be changed to a 10 year interval since there is a provision for re-verification with an associated 10% system change. 4) In R1.2 and R2.2, the phrase "same information" is used, while in M1 and M2 the phrase "equivalent information" is used - we suggest changing R1.2 and R2.2. to match the M1 and M2.

Organization	Yes or No	Question 14 Comment
		5) Specifying Normal Operating H2 pressure in Attachment 1, section 2.5 may not produce the desired maximum Q cap results - consider changing "normal operating " to "maximum sustainable (within design limits)" 6) In Attachment 1, section 2.2, we suggest changing "they could normally be expected to operate" to "they are normally expected to operate". 7) We suggest revising Requirements R1.3 and R2.3 to read: "Submit the capability information to its TP within 90 calendar days of completion of the verification." to clarify these requirements and to make them consistent. We also believe 90 days will create an undue hardship for GOs who own a large number of generators and thus we also request that this requirement be revised to allow additional time when authorized by the TP or PC. 8) The first paragraph of the Compliance Data Retention Section D 1.2 is difficult to understand. Please simplify using multiple sentences, if possible. 9) In the VSL table for R1 and R2, we suggest changing the phrasing "from the date the data was recorded" to "from the verification date" each time it is used (7 times). 10) In the VSL table for R1, both the first and fourth items are not needed in the list of the four items which make up the OR statement. It is sufficient to measure if the data is more than 30 days late to be categorized as Severe. 11) In the VSL table for R2, we suggest replacing the second item in the list of the two items which make up the OR statement to match the corresponding item in R1 relative to the tardiness of the submission to the TP greater than 30 days late (> 120 days total). 12) Revise attachment 1 section 5.1 and 5.2 to change “last more than 6 months” to “last more than 1 year,” to align with the typical long-term planning horizon. 13) It is noted that MOD-11which is supposed to clarify modeling data requirements has not yet been completed and approved. Yet MOD-25 is requiring verification of this data. It is also recognized that generator verification methods are producing results that are not being directly used in the models (due to various operating or system limitations) .As a result, it is not clear that MOD-025 is achieving the reliability purpose intended. 14) This standard establishes a periodic generator testing regime which, when implemented on a large number of generators, creates a continuous state of testing across the BES. We question if this approach really improves the reliability of the BES. The use of normal operational data, supplemented by analysis, represents a better approach to verify reactive capability for most generators. Targeted testing can then be

Organization	Yes or No	Question 14 Comment
		used on a limited basis.

Response: The GVSDT thanks you for your comment.

(1) **Response: The standard only requires testing once every five years. Operating a low capacity factor unit for one hour every five years should not be a burden.**

(2) **Response: The GVSDT believes that engineering analysis alone does not provide verification of equipment.**

(3) **Response: The five- year interval was chosen to ensure that equipment degradation or inadvertent or unknown changes would be identified.**

(4) **Response: The GVSDT agrees and has modified the standard to use the same wording in both the measures and requirements.**

(5) **Response: The intent of the standard is to capture the normal operating capability.**

(6) **Response: The GVSDT agrees and has modified the standard as suggested. The phrase, "could normally be expected" was changed to "are normally expected."**

(7) **Response: The GVSDT has modified the language to improve clarity. The GVSDT believes the 90-day time period specified is sufficient for submitting data**.

(8) **Response: This is standard language. The GVSDT believes language is clear.**

(9) **Response: The GVSDT has modified the standard's VSLs for clarity by changing "date data was recorded" to "date of verification."**

(10) **Response: The GVSDT believes that all the items in the "or" statement are needed to characterize a possible severe violation level. VSLs should identify a wide range of possible noncompliance.**

(11) **Response: The GVSDT believes that all the items in the "or" statement are needed to characterize a possible severe violation level.**

(12) **Response: The GVSDT believes that the six- month time frame specified is appropriate given most Transmission Planners run simulations annually. Extending the time period to one year increases the likelihood that the changes discovered may not exist when performing the next simulation.**

(13) **Response: Since system conditions can be a limiting factor, no test can assure that the rated values of the excitation equipment and generator will be reached during a test. The GVSDT believes that testing as close as possible to the Pmax and Qmax point will identify most issues with equipment, and the reliability purpose will be achieved. Through Order 693, the FERC has required testing at other points in order to help define the entire performance curve for the unit. Please advise if the commenter has specific suggestions on how to better achieve this reliability purpose. Note that the intent of MOD-025 is to verify the accuracy of specific data used in long-range planning, not Real-time operations. While MOD-011 was not approved by FERC, it is effective in some Canadian Provinces and in the United States. FERC advised that entities "should" comply with MOD-011. (From Order 693: In the interim, compliance with MOD-011-0 should continue on a voluntary basis, and the Commission considers compliance with the**

Organization	Yes or No	Question 14 Comment
Reliability Standard to be a matter of good utility practice.) (14) **Response: Normal operational data is allowed by the standard.**		
Tennessee Valley Authority GO	Yes	1) This requirement will require units that normally do not run or have a very low capacity factor to be verified. Please add a provision for excluding these requirements for units that do not regularly run, similar to other NERC standard exemption requirements. 2) The standard needs to allow the inclusion of engineering analysis (with operational data) to supplement or replace testing when appropriate. It is noteworthy that the original NERC Board Approved version of this standard states in requirement R1.3 that acceptable methods for reactive capability verification "include use of commissioning data, performance tracking, engineering analysis, testing, etc." This represents the "allowance to use of all the tools in the toolbox" approach which is appropriate when no single tool is sufficient to accomplish the stated reliability objectives, consistent with the FERC Acceptance Criteria of a Reliability Standard (reference Paragraphs 321, 324, 328, 332). This approach is reflected in the SERC regional procedure for MOD-025-1 which was developed by a joint transmission-generation task force. 3) The 5-year test interval should be changed to a 10 year interval since there is a provision for re-verification with an associated 10% system change. 4) In R1.2 and R2.2, the phrase "same information" is used, while in M1 and M2 the phrase "equivalent information" is used. We suggest changing R1.2 and R2.2. to match the M1 and M2. 5) Specifying Normal Operating H2 pressure in Attachment 1, section 2.5 may not produce the desired maximum Q cap results. Consider changing "normal operating " to "maximum sustainable (within design limits)" 6) In Attachment 1, section 2.2, we suggest changing "they could normally be expected to operate" to "they are normally expected to operate". 7) We suggest revising Requirements R1.3 and R2.3 to read: "Submit the capability information to its TP within 90 calendar days of completion of the verification." to clarify these requirements and to make them consistent. We also believe 90 days will create an undue hardship for GOs who own a large number of generators and believe this requirement should allow for additional time when authorized by the TP or PC. 8) The first paragraph of the Compliance Data Retention Section D 1.2 is difficult to understand. Please simplify using multiple sentences, if possible. 9) In the VSL table for R1 and R2, we suggest changing the phrasing "from the date the data was recorded"

Organization	Yes or No	Question 14 Comment
		to "from the verification date" each time it is used (7 times). 10) Revise attachment 1 section 5.1 and 5.2 to change “last more than 6 months” to “last more than 1 year,” to align with the typical long-term planning horizon. 11) It is noted that MOD-11, which is supposed to clarify modeling data requirements, has not yet been completed and approved. Yet MOD-25 is requiring verification of this data. It is also recognized that generator verification methods are producing results that are not being directly used in the models (due to various operating or system limitations). As a result, it is not clear that MOD-025 is achieving the reliability purpose intended. 12) This standard establishes a periodic generator testing regime which, when implemented on a large number if generators, creates a continuous state of testing across the BES. We question if this approach really improves the reliability of the BES. The use of normal operational data, supplemented by analysis, represents a better approach for most generators. Targeted testing can have application on a limited basis.
Response: The GVSDT thanks you for your comment. (1) **Response: The standard only requires testing once every five years. Operating a low capacity factor unit one hour every five years should not be a burden.** (2) **Response: The standard allows engineering analysis to supplement operating data as specified in Note 2 of Attachment 1. Since engineering analysis cannot verify the performance of equipment, it is not a substitute for staged testing or operational data.** (3) **Response: The five-year interval was chosen to ensure that equipment degradation or inadvertent or unknown changes would be identified.** (4) **Response: The GVSDT agrees and has modified the standard to use the same wording in both the measures and requirements.** (5) **Response: The intent is to capture the normal operating condition and not to increase hydrogen pressure or make other alteration just for testing.** (6) **Response: The GVSDT has changed the standard to clarify this point. The phrase, “could normally be expected” was changed to “are normally expected.”** (7) **Response: The GVSDT believes that 90 days provides sufficient time and is not a hardship.** (8) **Response: This is standard language. The GVSDT believes language is clear.** (9) **Response: The GVSDT has modified the standard’s VSLs for clarity by changing “date data was recorded” to “date of verification.”** (10) **Response: The GVSDT believes that the six- month timeframe specified is appropriate.** (11) **Response: Since system conditions can be a limiting factor, no test can assure that the rated values of the excitation equipment and generator will be reached during a test. The GVSDT believes that testing as close as possible to the Pmax and Qmax point will identify most issues with equipment,**		

Organization	Yes or No	Question 14 Comment
and the reliability purpose will be achieved. Through Order 693, the FERC has required testing at other points in order to help define the entire performance curve for the unit. Please advise if the commenter has specific suggestions on how to better achieve this reliability purpose. Note that the intent of MOD-025 is to verify the accuracy of specific data used in long-range planning, not Real-time operations. While MOD-011 was not approved by FERC, it is effective in some Canadian Provinces and in the United States. FERC advised that entities "should" comply with MOD-011. (From Order 693: In the interim, compliance with MOD-011-0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.) (12) **Response: Normal operational data is allowed by the standard.**		
Southern Company	Yes	1) This requirement will require units that normally do not run or have a very low capacity factor to be run for testing. Please consider a provision for excluding these requirements for units that do not regularly run unless verification using engineering analysis is allowed. 2) Each of the methods of verification proposed have merits and deficiencies. For staged testing, there exists the risk of tripping a unit during testing. System conditions which allow for the maximum reactive power output production/absorption are extreme system voltage conditions - precisely where it is undesirable to perform such testing or trip a unit. Staged testing or verification using operational data during normal system voltage conditions will result in reactive limits constrained by system conditions (not representative of the actual unit capabilities for extreme voltage conditions when the reserve Var capabilities are needed most). Staged testing may, however, reveal unknown thermal or mechanical problems which, while are good to know, are maintenance related and are not the primary objective of the standard which is verification of reactive capability for use in planning models (Long Term Planning Horizon). But, if system constraints during staged testing do not permit a unit to reach the reactive limits the unit could reach during extreme system voltage conditions, one could argue the results of the test are inconclusive in terms of meeting the reliability objective of the standard. Our experience has shown that unit reactive limits for extreme voltage conditions (when the reserve Var capabilities are needed most) can best be determined using engineering analysis. It is noteworthy that the original NERC Board Approved version of this standard states in requirement R1.3 that acceptable methods for reactive capability verification "include use of commissioning data, performance tracking, engineering analysis, testing, etc." This represents the "allowance to use of all the tools in the toolbox" approach which is appropriate when no single tool is sufficient to accomplish the stated reliability objectives, consistent with the FERC Acceptance Criteria of a Reliability Standard (reference Paragraphs 321, 324, 328, 332). This approach is reflected in the SERC Regional Criteria for MOD-025-1 which was developed by a joint transmission-generation task force. 3) The test interval and new unit test requirement described in Attachment 1, part 5 should be included in the

Organization	Yes or No	Question 14 Comment
		main standard requirement section rather than in the staged test details. However, we believe re-verification every 5 years is too frequent. We agree that re-verification is appropriate for significant changes that impact the real or reactive capability by more than 10%, but we question the six month criteria. For the Long Term Planning Horizon, one year would be more appropriate. 4) In R1.2 and R2.2 the phrase "same information" is used, while in M1 and M2 the phrase "equivalent information" is used - we suggest changing R1.2 and R2.2. to match the M1 and M2. 5) Specifying Normal Operating H2 pressure in Attachment 1, section 2.5 may not produce the desired maximum Q cap results - consider changing "normal operating " to "maximum sustainable (within design limits)" 6) In Attachment 1, section 2.2, we suggest changing "they could normally be expected to operate" to "they are normally expected to operate". 7) We suggest revising Requirements R1.3 and R2.3 to read: "Submit the capability information to its TP within 90 calendar days of completion of the verification." to clarify these requirements and to make them consistent. We also believe 90 days will create an undue hardship for GOs who own a large number of generators and believe this requirement should allow for additional time when authorized by the TP or PC. 8) The first paragraph of the Compliance Data Retention Section D 1.2 is difficult to understand. Please simplify using multiple sentences, if possible. 9) In the VSL table for R1 and R2, we suggest changing the phrasing "from the date the data was recorded" to "from the verification date" each time it is used (7 times). 10) In the VSL table for R1, both the first and fourth items are not needed in the list of the four items which make up the OR statement. It is sufficient to measure if the data is more than 30 days late to be categorized as Severe. In the VSL table for R2, we suggest replacing the second item in the list of the two items which make up the OR statement to match the corresponding item in R1 relative to the tardiness of the submission to the TP (> 30 days late)

Response: The GVSDT thanks you for your comment.

(1) **Response: The standard only requires testing once every five years. Operating a low capacity factor unit one hour every five years should not be a burden.**

(2) **Response: Since system conditions can be a limiting factor, no test can assure that the rated values of the excitation equipment and generator will be reached during a test. The GVSDT believes that testing as close as possible to the Pmax and Qmax point will identify most issues with equipment,**

Organization	Yes or No	Question 14 Comment
and the reliability purpose will be achieved. Through Order 693, the FERC has required testing at other points in order to help define the entire performance curve for the unit. Engineering analysis alone does not verify the functionality or health of equipment and thus cannot serve as a verification method. Please advise if the commenter has specific suggestions on how to better achieve this reliability purpose. (3) **Response: Guidance was received from NERC on how to develop an attachment referenced by requirements. The attachment contains procedural elements needed for satisfying the requirements. The requirements require verification of performance and timely reporting of data to the Transmission Planner. The GVSDT believes that the six-month timeframe specified is appropriate.** (4) **Response: The GVSDT agrees and has modified the standard to use the same wording in both the measures and requirements.** (5) **Response: The intent is to capture the normal operating condition and not to increase hydrogen pressure or make other alteration just for testing.** (6) **Response: The GVSDT has changed the standard to clarify this point. The phrase, "could normally be expected" was changed to "are normally expected."** (7) **Response: The GVSDT believes that 90 days provides sufficient time and is not a hardship.** (8) **Response: This is standard language. The GVSDT believes language is clear.** (9) **Response: The GVSDT has modified the standard's VSLs for clarity by changing "date data was recorded" to "date of verification."** (10) **Response: The GVSDT believes that all the items in the "or" statement are needed to characterize a possible severe violation level. VSLs should identify a wide range of possible noncompliance.** **(11) Response: The GVSDT believes that all the items in the "or" statement are needed to characterize a possible severe violation level.**		
Duke Energy	Yes	1) This requirement will require units that normally do not run or have a very low capacity factor to be verified. Please add a provision for excluding these requirements for units that do not regularly run, similar to other NERC standard exemption requirements. 2) MVAR validation issues should be combined with generation FAC-8 issues to eliminate confusion that these separate standards have caused. 3) Specifying Normal Operating H2 pressure in Attachment 1, section 2.5 may not produce the desired maximum Q cap results - consider changing "normal operating " to "maximum sustainable (within design limits)" 4) We suggest revising Requirements R1.3 and R2.3. Data should be submitted to the TP at the next annual update provided on MOD-010 model data. 5) Revise attachment 1 section 5.1 and 5.2 to change "last more than 6 months" to "last more than 1 year," to align with the typical long-term planning horizon. 6) It is noted that MOD-11 which is supposed to clarify modeling data requirements has not yet been

Organization	Yes or No	Question 14 Comment
		completed and approved. Yet MOD-25 is requiring verification of this data. It is also recognized that generator verification methods are producing results that are not being directly used in the models (due to various operating or system limitations). As a result, it is not clear that MOD-025 is achieving the reliability purpose intended. 7) Since GO/GOPs do not always model electrical systems, nor participate in interconnected system models groups such as the Master Model Working Group (MMWG), there probably needs to be a guide that clearly identifies the steps a GO/GOP needs to take to maintain models up to date. The NATF and EPRI/NAGF is considering a collaboration to do so.
Response: The GVSDT thanks you for your comment. (1) **Response: The standard only requires testing once every five years. Operating a low capacity factor unit one hour every five years should not be a burden.** (2) **Response: FAC-008 deals with Facility ratings methodology whereas MOD-025 is concerned with verification of those ratings. THE GVSDT is unsure of the confusion that is indicated.** (3) **Response: The intent is to capture the normal operating condition and not to increase hydrogen pressure or make other alteration just for testing.** (4) **Response: The MOD-025 standard requires the data to be submitted within 90 days after verification. This time period may or may not correspond with MOD-010 data submission requirements.** (5) **Response: The GVSDT believes that the six month timeframe specified is appropriate.** (6) **Response: Since system conditions can be a limiting factor, no test can assure that the rated values of the excitation equipment and generator will be reached during a test. The GVSDT believes that testing as close as possible to the Pmax and Qmax point will identify most issues with equipment, and the reliability purpose will be achieved. Through Order 693, the FERC has required testing at other points in order to help define the entire performance curve for the unit. Please advise if the commenter has specific suggestions on how to better achieve this reliability purpose. While MOD-011 was not approved by FERC, it is effective in some Canadian Provinces and in the United States. FERC advised that entities "should" comply with MOD-011. (From Order 693: In the interim, compliance with MOD-011-0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.)** (7) **Response: The creation of the guide suggested is outside the scope of the project SAR. The commenter may consider submitting a SAR for this issue.**		
Ameren	Yes	(1)If a demonstrated value is less than the corresponding expected value, then the generator owner should be required to provide calculated values for reactive capability in addition to the demonstrated values (this should be included in R1). Without this, the data is useless to the Transmission Owners for system modeling use.

Organization	Yes or No	Question 14 Comment
		(2) There may be different usage of the term 'point of interconnection" in the industry. We suggest the SDT to consider proposing a formal definition of this term. (3) We understand the 20% and 10% variances allowed in the draft are for testing purposes. However, it's unclear how they should be used. For example, are they relative to the results at time of seasonal peak, or just maximum output at the time of testing? (4) Notes 1 and 2 should be Requirements. It is difficult to determine how compliance with footnotes will be audited. (5) Engineering judgment should be clearly allowed when meter data (for example no meter at the high side of a GSU), auxiliary data, etc. is not available as required in Attachment 1. (6) Sister Unit exemptions should be allowed for generators that are essentially identical and operated in an identical fashion.
Response: The GVSDT thanks you for your comment. (1) **Response: Calculated values do not provide verification of equipment capability.** (2) **Response: The GVSDT believes that the diagram in Attachment 2 clearly identifies the intent of the term "point of Interconnection."** (3) **Response: The GVSDT has revised the language for clarity. The revised standard, Attachment 1, step 2 states:** **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** (4) **Response: Notes 1 and 2 are informational and do not contain actions that are auditable. Note 2 specifically states that it is not required by the standard.** (5) **Response: The standard allows engineering analysis if metering does not exist at a particular location.** (6) **Response: The standard requires verification only once every five years. The GVSDT believes to maintain reliability every unit should be verified once every five years.**		
SERC Dynamics Review Sub-committee	Yes	The VSL for R2 is missing a needed component. The Severe category needs to include the following: "The Transmission Owner verified and recorded the Real and Reactive Power capability of its applicable synchronous condenser, but submitted the data to its Transmission Planner more than 120 calendar days from the date the data was recorded."

Organization	Yes or No	Question 14 Comment
		GO's should be required to provide expected values for reactive capability in addition to the demonstrated values (this should be included in R1). Without this, the data is useless to the Transmission Planners. Item 3.4 in Attachment 1 refers to Transmission Owner. It should say Transmission Planner to match Requirements 1 & 2. Only one verification is needed for sister (identical) units. The standard currently requires verification for all units.
Response: The GVSDT thanks you for your comment. (1) **Response: A synchronous condenser does not have Real Power capability.** (2) **Response: Engineering analysis is allowed. Expected values are not required because the GVSDT does not believe the results constitute verification.** (3) **Response: This has been revised to Transmission Planner.** (4) **Response: The standard requires verification only once every five years. The GVSDT believes to maintain reliability every unit should be verified once every five years.**		
IRC Standards Review Committee (joint comments)	Yes	The proposed MOD-025-2 standard appears to violate many conventions, such as: o The use of Attachments for mandating requirements o The combinations of different actions in the same requirement o The mandating of specific formats
Response: The GVSDT thanks you for your comment. **(1) Response: The requirement would be cumbersome without including the attachment. The use of the attachment improves requirement clarity and is supported by NERC's standards staff.** **(2) Response: Requirement R1 has been split into separate requirements to resolve this concern.** **(3) Response: The standard calls for data to be submitted and a sample form is provided for reference. The GVSDT has included the information necessary for meeting the reliability objective of the standard. Entities can use their own form for submitting data and this is clear in the revised standard**		
Pepco Holdings Inc Affiliates	Yes	Should Attachment 1 Sec 5 be added to the standard list of requirements instead of part of the attachment? It

Organization	Yes or No	Question 14 Comment
		appears that this section is more than just additional details on verification and reporting. In the project background information it is stated ". If regions have generating units that are connected at under 100 kV that are important to the reliability of the system due to some local consideration, then the region has the authority to require that those units be verified if they so choose." This capability should be noted directly in the standard.
Response: The GVSDT thanks you for your comment. **(1) Response: The requirement states that verification is performed in accordance with the procedure listed in Attachment 1. The GVSDT believes the attachment contains procedural elements needed for satisfying the requirements. The requirements require verification performance and timely reporting of data to the Transmission Planner.** **(2) Response: This is a part of the delegation agreements and the NERC Rules of Procedure.**		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	Please consider the following comments: 1. Attachment 1, Item 2 - Add the adjective "gross" to the Real Power and Reactive Power reference for added clarity and to assure awareness that the verification is for "gross", rather than "net" values. 2. Attachment 1, Item 2 - Modify the wording of "with all auxiliary equipment needed for expected normal operation" to "with all auxiliary and voltage regulation equipment, such as reactive power compensation, needed for expected normal operation and voltage regulation" to assure that any reactive power compensation equipment (e.g. capacitor banks, SVCs, STATCOMs) are not overlooked and omitted from the verification data. This added text is particularly needed for wind generation situations. 3. Attachment 1, Item 2 - We would prefer the acceptable verification with operational data to be 10%, rather than 20%. 4. Attachment 1, Item 2 - Expand the text of "expected value" to "expected maximum gross Real and Reactive Power Generator capability values" to add more clarity. 5. Attachment 1, Item 2.1 - Add the adjective "gross" to the Real Power and Reactive Power reference for added clarity and to assure awareness that the verification is for "gross", rather than "net" values. 6. Attachment 1, Item 2.1 - Replace the wording "at rated gross Real Power capability" with "at the generating unit's normal expected maximum Real Power capability" and drop the footnote reference. 7. Attachment 1, Item 2.2 - Add the adjective "gross" to the Real Power and Reactive Power references for added clarity and to assure awareness that the verification is for "gross", rather than "net" values.

Organization	Yes or No	Question 14 Comment
		8. Attachment 1, Item 2.4 - We think that both "2.1 and 2.2" should be referenced for the over-excited data. If this is incorrect, then please explain why 2.1 should be omitted. 9. Attachment 1, Item 2.6 - Add an Item 2.6 of "Record the generator step up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU transformer". This addition will help avoid the omission of the GSU transformer reactive power losses when calculating the gross generation power capabilities when high side measurements were taken. We are aware that this oversight has already occurred several times. [Add Point "F" (pointing to the generator step up transformer) to the Verification Information Reporting Form in Attachment 2 to accommodate and remind the Generator Owner or Transmission Owner to record these losses, when it is needed.] 10. Attachment 1, Item 3.4 - Correct the functional entity reference from "Transmission Owner" to "Transmission Planner". Revise the wording to allow the Generator Owner or Transmission Owner to report, "The ambient air temperature and/or ambient water temperature at the end of the verification period". [Require that the 'basis' ambient air temperature and/or ambient water temperature associated with the reported gross generator Real Power capabilities be stated on the Verification Information Reporting Form along with a correction factor if any, to allow the Transmission Planner to correct the Real Power capability to different ambient temperatures, if needed.] 11. Attachment 1, Item 3.7 - Add an Item 3.7 of "The GSU transformer losses if the verification measurements were taken from the high side of the GSU transformer." This addition will help avoid the omission of the GSU transformer reactive power losses when calculating the gross generation power capabilities when high side measurements are taken". 12. Attachment 1, Item 5.3 - Add revise the wording, "within one year of their commercial operation" to "within one year of their commercial operation or as scheduled by the applicable Transmission Planner" to allow the exception of an earlier or later due date when it may be appropriate and agreed to be the affected Transmission Planner. 13. Attachment 2, Item A - Add a note that the individual unit values should be reported separately whenever the verification measurements were taken at the individual unit. In most cases, the individual units are modeled separately (including compound units) in the power flow cases and the loss of individual units are simulated in system planning assessments. So, if the verification data was collected in a manner that would allow individual unit power capability verification, then the reporting form should not direct the Generator Owner or Transmission Owner to mask this information. 14. Attachment 2, Item F - As noted above, add a Point "F" (pointing to the generator step up transformer) to the Verification Information Reporting Form to refer to the GSU transformer losses. Also add a Point "F" row to the data table with entries that indicate to provide the GSU transformer MW and MVAR losses

Organization	Yes or No	Question 14 Comment
		when the verification data was based on measurements that were taken from the high side of the GSU transformer. Otherwise, GOs and TOs that base verification values on measurements from the high side of the GSU transformer may forget to make the proper correction when they calculate the gross values for Point "A", as others have historically done. The scope of this standard does not include the verification of high voltage power flow controllers that are connected to the transmission system at 100 kV or above. We propose that a Standard Authorization Request (SAR) be created to address the power capability verification gap that is not being filled with this standard. The test form has remarks space for reactive limit constraints but not for real power constraints. 15. Attachment 1 , #2, the use of the word "all" auxiliary equipment is unnecessary and is over reaching, the Requirement is for expected normal operation. Recommend deleting "all" from this sentence. 16. Attachment 1, # 2.1, should the SDT give an alternate threshold if "90%" could not be achieved during the testing window?
Response: The GVSDT thanks you for your comment. **(1) Response: The Attachment 2 form makes the data requirement clear. Other values are recorded in addition to gross values.** **(2) Response: The GVSDT believes the current verbiage, "with all auxiliary equipment" is sufficient to address this concern. The capacitor banks, SVCs, and STATCOMs are not part of this standard. The GVSDT recognizes these are important reactive resources and has suggested a SAR be created to address them.** **(3) Response: The GVSDT has modified the Attachment to use 10percent of the last staged test rather than 20percent.** **(4) Response: The GVSDT has removed the "expected value" phrase. The sentence now reads "…is at least 90percent of a previously staged test where a voltage limitation was reached"** **(5) Response: The Attachment 2 form makes the data requirement clear. Other values are recorded in addition to gross values.** **(6) Response: The GVSDT concurs and has revised the language as suggested.** **(7) Response: The Attachment 2 form makes the data requirement clear. Other values are recorded in addition to gross values.** **(8) Response: Item 2.1 was omitted from the over-excited case in Item 2.4 because it is covered in Item 2.3.** **(9) Response: The GVSDT concurs and has revised the language as suggested and added a section to Attachment 2 for recording the value.** **(10) Response: The GVSDT has corrected the reference to indicate the Generator Owner as the entity to record the ambient conditions in case there is a need to perform a correction... The GVSDT has also revised the ambient condition correction language.** **(11) Response: The GVSDT concurs and has made the revision suggested.**		

Organization	Yes or No	Question 14 Comment
(12) Response: The GVSDT believes this suggestion adds ambiguity to the standard and may create compliance issues. The one-year requirement will be retained. **(13) Response: The GVSDT concurs and has made the revision suggested.** **(14) Response: A section was added to Attachment 2 for recording the value for the GSU losses. The commenter is encouraged to submit a SAR to address the remainder of this comment. The remarks space can be used to document either Real or Reactive power constraints.** **(15) Response: The GVSDT disagrees and has retained the word "all."** **(16) Response: The GVSDT has added the following verbiage to Attachment 1, Item 2.1 to address this concern:** **"If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, the Generator Owner must document the reasons it was unable to meet the threshold and test to the full capability at the time of the test. The Generator Owner shall retest the Facility within six months of being able to reach the ninety percent threshold."** **If a Facility has an issue that affects the output by 10percent for more than six months, the Facility is to be re-rated per Item 5.1 in Attachment 1.**		
SPP Reliability Standards Development Team	Yes	VSLS for R2 there is an extra applicable in the chart. Would suggest removing.
Response: The GVSDT thanks you for your comment. The chart has been corrected.		
SERC Planning Standards Subcommittee	Yes	If the demonstrated value is less than the expected value, then the GO's should be required to provide calculated values for reactive capability in addition to the demonstrated values (this should be included in R1). Without this, the data is useless to the Transmission Planners. "The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers"
Response: The GVSDT thanks you for your comment. The GVSDT believes that calculations do not provide verification that a unit or Facility can reach the specified operating point.		
Idaho Power-Power Production	Yes	1. The language in the Applicability Section 4.2.1, implies that the standard applies to only synchronous condensers in generating facilities. Please clarify. 2. As stated before, we believe that FAC-008 and FAC-009 specify our generator have a normal and emergency rating. The standards should use similar language in requiring validation of capability.

Organization	Yes or No	Question 14 Comment
		However, our regional policy required by MOD-010, specifies validation of the generator reactive capability, thus we believe this standard is redundant and not needed. That is unless MOD-010 is going to be retired. 3. Note 1 in Attachment 1 states that the data point may not match the manufacturer capability curve or the verified values for the MOD-010 standard. We question what the point of this standard is if not to validate. Note 1 mentions other items that might be discovered during the validation required by this standard, but we believe those benefits are achieved by our existing validation policy.
Response: The GVSDT thanks you for your comment. **(1) Response: The GVSDT has revised 4.2.1 to state:** "Individual generating unit greater than 20 MVA (gross nameplate rating) in a generating Facility or synchronous condenser greater than 20 MVA (gross nameplate rating) connected at the point of Interconnection at 100 kV or above." **(2) Response: The GVSDT is not aware of any effort to retire MOD-010. MOD-025 requires verification of Real and Reactive power capability of a unit or synchronous condenser. The verification is performed for normal capability, not emergency capability. FAC-008 and FAC-009 specify a methodology for developing Facility ratings whereas MOD-010 pertains to data and equipment characteristics, not validation requirements. The standards do not duplicate requirements.** **(3) Response: The GVSDT believes that reactive power limitations originating inside the generating station (e.g., hydrogen pressure, thermally sensitive generator, voltage regulator settings, excitation problems, etc.) need to be verified by testing. MOD-025 is a verification standard. Note 1 addresses the possibility that a unit may not be able to reach the D-curve value because of limitations outside owner control. MOD-010 is not a verification standard.**		
Santee Cooper	Yes	Attachment 1 Item 1 requires testing of units that are 20 MVA and above to be tested a second time if they are tested as part of the aggregate.
Response: The GVSDT thanks you for your comment. The GVSDT disagrees with your assertion. Units rated greater than 20 MVA are individually verified. Units 20 MVA or less can be verified individually or in aggregate. Item 1 states: "For units of 20 MVA or less that are part of a plant greater than 75 MVA in aggregate, record data either on an individual unit basis or as a group. Perform verification individually for every generating unit greater than 20 MVA (gross nameplate rating)."		
PPL Generation	Yes	PPL offers the following comments on Attachment 1:

Organization	Yes or No	Question 14 Comment
		1. Att. 1, para. 2: Change the final sentence to end, "within 20% of the expected real and reactive power values."Reason: Clarification Att.1, footnote to para. 2.1: Change "normal expected maximum" to "normal," and "at the time of the verification" to "for the ambient conditions during the verification."Reason: Clarification. The normal output of a unit is often not its (emergency) maximum generation, and the word "ambient" works better than "time." 2. Att. 1, para. 2.1, 1st sentence: Change "at rated gross Real Power capability" to "within 20% of the Real Power capability."Reason: Clarification, see the comment above to para. 2. Also, the terms capability and rating have different meanings. 3. Att. 1, para. 2.1, last sentence: Change "possible" to "practical" 4. Att. 1, para. 2.2: Change exception in 1st sentence to "other than wind, photovoltaic and peaking (capacity factor < 10%)."Reason: Given that peaking units typically operate only during periods of maximum demand, it can be difficult to establish a realistic min power expectation, this exercise would add little or no value, and such testing would be unnecessarily economically burdensome. 5. Att.1, para. 2.3: Add at end, "for baseload units. Values for peaking units (<10% capacity factor) may be recorded as soon as they are reached. Reason: The dispatch volatility of peaking units can make a one-hour hold-period unnecessarily economically burdensome. 6. Att. 1, para. 2.5: Add at end, "if attainable. Otherwise a 10% variation is acceptable. Reason: Hydrogen pressure can vary, and minor disturbances should not disqualify an otherwise-acceptable test. 7. Att. 1, para. 3.2: Clarification is needed. Is the standard saying that a special-for-test voltage schedule should be established with the RTO? 8. Att. 1, para. 3.3: Add at the end, "one or the other of these values may be calculated, if metering is not present at both locations."Reason: Same concept as para. 4.1. 9. Att. 1, Note 1, 1st sentence: Add at the end, "or unit auxiliary system voltage limits or facility operational practices." Make the same change also for "transmission system conditions" in the third sentence. Reason: VAR testing involves creating abnormal voltages at the generator terminals and in the feeds to auxiliary equipment. Drop-out of aux motors can constitute the practical test limit. It is appropriate to apply safety margins in this respect (ref. facility operational practices), lest units be at risk of tripping in the course of conducting a reliability test. 10. Att. 1, Note 2: Clarification is needed regarding the less-restrictive conditions being referred-to. 11. Att. 1, para 3.4: Replace "and a correction factor...if needed" with "and, if requested, correction to other ambient conditions."Reason: Correction often involves more than a simple multiplication factor, especially

Organization	Yes or No	Question 14 Comment
		when using a thermodynamic computer model for this purpose. This exercise includes truncating corrections to lower ambients for GSU and generator limits, if necessary. 12. General: The generator OEM D-curve constitutes a rating, not a capability, and is applicable only at rated voltage. VAR testing involves identifying a capability at abnormal voltages, and is thus likely to rarely if ever match the D-curve. 13. General: Where the RTO has an effective VAR testing program in place (as is the case for PJM) the results should be acceptable as-is for NERC compliance purposes, lest there be created two different tests, resulting in reporting of two different reactive capabilities to two different entities.

Response: The GVSDT thanks you for your comment.

(1) Response: The GVSDT has revised the sentence to state: "Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability as long as that operational data meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50percent of the capability shown on the associated D-Curve. percent

(2) Response: The GVSDT has removed the footnote and revised the sentence based on other stakeholder comments:

2.1. Verify Real Power capability, Reactive Power capability over-excited (lagging) and Reactive Power capability under-excited (leading) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power at the time of the verifications.

(3) Response: See responses above.

(4) Response: We concur with adding wind and photovoltaic and have made the revision suggested. We do not concur with providing the exception to other units as the standard applies to applicable Facilities that meet registration criteria. Item 2.2 also contains the phrase, "minimum Real Power output at which they are normally expected to operate." If a peaking unit only operates at maximum output, then this is how the unit should be verified.

(5) Response: The GVSDT does not have evidence that exempting these additional units will not adversely impact reliability. The verification is only required to be performed for one hour every five years. The GVSDT does not believe this is an economically burdensome requirement.

(6) Response: Paragraph 2.5 does not specify a pressure or bandwidth. It is expected that verification will be performed at the normal pressure. In other words, at the pressure the unit usually operates.

(7) Response: The standard does not specify a special voltage schedule. Item 3.2 only states to record the voltage during the test. This voltage value may be the normal voltage schedule.

(8) Response: The GVSDT concurs and has revised item 3.3 by adding: "If only one of these values is metered, the other may be calculated."

Organization	Yes or No	Question 14 Comment
(9) Response: The standard does not require testing to exceed voltage limitations and risk equipment damage or jeopardize reliability. **(10) Response: The GVSDT has added the following phrase to the end of the sentence in Note 2: "Than those encountered during the verification," and changed "conditions" to "voltages" to provide clarity. The sentence now states:** **"While not required by the standard, it is desirable to perform engineering analysis to determine expected unit capabilities under less restrictive system voltages than those encountered during the verification."** **(11) Response: The verbiage of item 3.4 is designed to address the FERC Order 693 directive to provide this information. This language has been revised for clarity.** **(12) Response: The standard doesn't require a unit to reach the D-curve value. The D-curve does not reflect all unit limitations that may exist.** **(13) Response: If the requirements of the PJM standard satisfy the requirements of the NERC MOD-025-2 standard, then additional testing should not be necessary.**		
Dominion	Yes	Test form needs to be improved. Provide the form in format that can be electronically completed by the user.
Response: The GVSDT thanks you for your comment. The form was developed as an example. The commenter can develop an electronic form, if desired.		
FirstEnergy	Yes	Regarding Notes 1 & 2 in the standard: Generally we have found that reactive power limitations that originate inside the generating station (hydrogen pressure, thermally sensitive generator, voltage regulator settings, and excitation problems) usually cannot be overcome through engineering analysis on the part of the transmission planning engineer. These types of conditions can only be addressed by the GO. On the other hand, Generator Terminal Voltage limits, or Transmission System voltage Limits can be eliminated using engineering analysis to simulate a more stressed system. Attachment 1, R2 - Assuming there are no transmission system related limitations, how close does the test value for VARs have to come from the expected value to be considered "verified"? Attachment 1, R2.2 - Nuclear units should be exempt from having to test leading VAR capability as this would challenge the plant's licensing limits for safety bus minimum voltage. MOD-025-RFC-01 currently allows this exemption for nuclear plants. Attachment 1, NOTE 1 - For clarity, nuclear plant safety bus voltage limits should mentioned as a reason why D-Curve values may not be met during a test.
Response: The GVSDT thanks you for your comment.		

Organization	Yes or No	Question 14 Comment
(1) Response: The GVSDT agrees. **(2) Response: The goal of the requirement is to verify the actual Reactive Power capability of the unit, and not necessarily confirm a predetermined capability.** **(3) Response: If a nuclear plant has under-excited capability it should be tested within the unit's capability and declared safety margins.** **(4) Response: Note 1 has been revised for clarity, and the following sentence was added to Note 1:** "Auxiliary bus voltage limits should be observed"		
NERC Staff	Yes	The violation risk factors associated with Requirements R1 and R2 should be at least medium. Use of invalid models resulting from violation of these standards can produce erroneous results and adversely affect assumptions of the electrical state or capability of the bulk electric system, or the ability to effectively control or restore the bulk electric system, particularly under emergency, abnormal, or restorative conditions. This can result in operating beyond the true stability limits of the system. The models validated by application of this standard are used in both the long-term planning and the operations planning horizon. The time horizon for Requirements R1 and R2 should include the operations planning horizon. The SDT should consider use of the word "verification" versus "validation" and assure that the term used in this standard is consistent with other standards.
Response: The GVSDT thanks you for your comment. The GVSDT agrees and has modified the standard accordingly (VRF's are now Medium)		
Public Service Enterprise Group	Yes	We have listed several concerns and questions below: a. We believe that Reactive Power capability at minimum Real Power output needs to be verified when a unit is installed and only verified thereafter when the generator itself is modified. Performing such tests will be difficult to run due to system voltage limitations at minimum Real Power generator output. This would require a modification or Attachment 1, paragraph 2.2, and paragraph 5. b. For the VSL's for requirement R2, the last paragraph of a Severe VSL should be modified as follows: "The TO verified and recorded the Reactive Power capability of its applicable synchronous condenser, but submitted the data to its Transmission Planner more than 120 calendar days from the date the data was recorded." c. The comments below reference Attachment 1. i. Paragraph 2 and its subparts would be more easily understandable if companion tables were provided that summarized the information. At last two tables would be helpful - one for traditional

Organization	Yes or No	Question 14 Comment
		dispatchable resources and one for variable resources. ii. In paragraph 3, whether the verification is staged or operational should be provided. iii. In paragraph 3.2, the requirement to supply the voltage schedule provided by the Transmission Operator would not appear to be applicable for a staged test. Trying to test Reactive Power limits while maintaining a prescribed voltage schedule in not practical.
Response: The GVSDT thanks you for your comment. **(1) Response: The standard allows the GO to test until a system limitation is met. This is the point that should be noted in the "remarks" section of Attachment 2 for the verification data. Equipment ages with use and needs to be re-verified periodically. The GVSDT has determined that testing every 5 years is required to maintain reliability. This comes directly from the previous version of the "fill-in-the-blank" standard. It also matches up well to the PRC-019 proposed standard. Although the two standards are separate it is anticipated that PRC-019 would be done before MOD-025. The MW testing portion of the standard is based on stakeholder consensus in previous posting of the SAR and draft standards. It was anticipated that the MW testing could be completed with little effort while doing MVAR testing.** **(2) Response: The wording in the VSLs has been corrected. However, based on comments from other stakeholders, the timing element was modified so that it is linked to the date of the test rather than the date of the recording.** **(3) Response: The GVSDT tried to develop companion tables but determined that it made the document harder to understand and did not add it to the Attachment. It was also viewed as being prescriptive. Paragraph 3 was revised per your suggestion and two check boxes were added to Attachment 2 for "Staged Test" and "Operational Data". Please see Attachment 2. It is recognized that a larger voltage schedule deviation is required to perform this task and this task should be coordinated with your TOP.**		
Arizona Public Service Company	Yes	The proposed VSL levels are spaced 10 days apart. For a test which is done once in a 5 year, it is unnecessarily restrictive. The minimum spacing between the VSLs should be 90 days. Reporting results 90 days late or even a 180 days late does not cause any concern for a planning horizon study. This data is only needed for such studies and such cases are typically updated annually. The real power verification tests are unnecessary and do not add any value. The peaking unit with less than 5% capacity factor should be exempt.
Response: The GVSDT thanks you for your comment. The GVSDT believes the VSL time frame specified is reasonable and is in alignment with NERC's VSL guidelines. **The FERC Order 693 requires verification of Real Power capability. The GVSDT does not have evidence that exempting the peaking units will not**		

Organization	Yes or No	Question 14 Comment
adversely impact reliability. **Because the verification is only required to be performed for one hour every five years the GVSDT does not believe this is a burdensome requirement.**		
Lakeland Electric	Yes	In the VSL table for Requirement R2, the word “applicable” appears twice in a row in the “Lower VSL” and “Moderate VSL” columns. Propose striking one instance of the word.
Response: The GVSDT thanks you for your comment. The error has been corrected.		
PacifiCorp	Yes	Section 4.2 of proposed Standard MOD-025-2 contemplates the inclusion of large wind farms within the scope of the proposed standard, as it is applicable to generating units above individual and aggregate nameplate rating thresholds (as the commentary seems to indicate is intended). The specific requirements for verifying Real and Reactive Power capabilities, however, do not make any allowance for operating differences of wind generation units. If wind generating resources are to be included within the scope of this proposed standard, then the standard should include express allowances for verification methodologies that are applicable to wind generating units.
Response: The GVSDT thanks you for your comment. The GVSDT believes the standard provides sufficient flexibility for wind farms. The GVSDT does not understand the ‘operating differences’ concern. Further explanation is needed before the GVSDT can provide a response.		
South Carolina Electric and Gas	Yes	If the demonstrated value is less than the expected value, then the GO's should be required to provide calculated values for reactive capability in addition to the demonstrated values (this should be included in R1). Without this, the data is useless to the Transmission Planners.
Response: The GVSDT thanks you for your comment. Engineering analysis is allowed. Expected values are not required because the GVSDT does not believe results obtained constitute verification.		
New York Independent System Operator	Yes	1. Effective Dates: How is this to be implemented? GOs may have units in multiple control areas. TOs may be in multiple areas. This seems impossible to track and may leave some areas without any verification for 5 years after the standard has been approved. The Planning Coordinator should be given the discretion to require and approve a test schedule within its area.

Organization	Yes or No	Question 14 Comment
		Additional NYISO Comments not addressed above for MOD-25-2 Under A. Introduction 2. Section 4 - Transmission Planner should be added under Functional Entities 3. Section 5.1.1 through 5.1.5 and 5.2.1 through 5.2.5 - These requirements should clarify that the Transmission owner requirement is for units that the Transmission owner owns and not for the generators in the Transmission Owners area. Under B. Requirements 4. Section 1.3 - The requirement should either be up to 225 days after the test or 60 days after the end of the test period. Attachment 1 - Verification of Generator Real and Reactive Power Capability 5. Section 1 - There should be some provision for allowing the verification results from small, electrically identical units at the same location to apply to other units in the group. 6. Section 2.1 - It is not practical to determine reactive power at rated gross Real Power capability. The requirement that ninety percent of wind turbines or photovoltaic inverters be online during verification of reactive power should be removed. 7. Section 2.2 - This verification is not needed. 8. Section 2.4 - Please clarify the definition of “limit”. 9. Section 3.2 - Please clarify the definition of “voltage schedule”. 10. Section 3.3 - This data is not needed. 11. o Section 3.4 - Ambient air temperature is not needed for reactive power test results. It is only necessary for certain generators in Real Power tests (combined cycle, combustion and turbine).

Organization	Yes or No	Question 14 Comment
		12. Section 4 - The diagram is not needed. 13. Section 4.1 - For the NYISO, Real Power verifications are conservatively measured as Net output, so no auxiliary loads are required to be reported. Attachment 2 14. Attachment 2 requires an unnecessary level of detail for "Data Type" to be recorded and collected; only gross MVAR, auxiliary reactive power and Net MW readings are required. 15. o What is meant by "MVAR values were adjusted to rate generator voltage"?

Response: The GVSDT thanks you for your comment.

(1) Response: The GVSDT believes the GO/TO, as applicable, is responsible to coordinate verification of all units with its TOP within the verification period identified in the standard. The Implementation Plan calls for various percentages of assets to be verified in each year over the phase-in period.

(2) Response: The TP is not responsible for any of the standard requirements and, therefore, is not listed in the Applicability Section. However, data is submitted to the TP.

(3) Response: The GVSDT believes the wording is clear.

(4) Response: The requirement has been modified for clarity.

(5) Response: The standard requires verification only once every five years. The GVSDT believes to maintain reliability every unit should be verified once every five years.

(6) Response: The GVSDT believes verification of Reactive Power at normal expected maximum Real Power is necessary for reliability. Section 2.1 has been modified to state:

> "**If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, the Generator Owner must document the reasons it was unable to meet the threshold and test to the full capability at the time of the test. The Generator Owner shall retest the Facility within six months of being able to reach the 90 percent threshold."**

(7) Response: The FERC Order 693 requires verification at multiple points, and the GVSDT believes verification of four points is necessary to approximate the capability curve.

(8) Response: A limit is the point, edge, or line beyond which something cannot or may not proceed. Examples include the thermal capability curve,

Organization	Yes or No	Question 14 Comment
aux bus voltage limit, voltage regulator limiter, or vibration limit. **(9) Response: Refer to VAR-001-1, Requirement 4.** **(10) Response: The GVSDT respectfully disagrees. This information is relevant for Transmission Planners to run accurate and reliable studies.** **(11) Response: Section 3.4 has been revised to include additional correction factor considerations so the GO must determine which ambient conditions need to be recorded for use as a correction factor for Real Power.** **(12) Response: The diagram was added for clarity.** **(13) Response: The GVSDT believes most generators do not meter net power. The standard allows for approximating auxiliary Load if an entity only meters the net power.** **(14) Response: The GVSDT believes most generators do not meter net power. The standard allows for approximating auxiliary Load if an entity only meters the net power.** **(15) Response: Many modern voltage regulators automatically adjust the under-excited limit to account for low bus voltage. A correction may be necessary to determine the limit for rated voltage.**		
Cowlitz County PUD	Yes	As already stated, Cowlitz questions the reliability benefit of the extensive reactive capability requirements and is currently consulting with Transmission Planners if such extensive data will actually be beneficial in their modeling efforts. It may be better to require data that must be verified though staged testing only after request by the Transmission Planner with a reasonable time frame to obtain the data.
Response: The GVSDT thanks you for your comment. Please refer to the previous response. The FERC Order 693 requires verification of Reactive capability at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve.		
Xcel Energy	Yes	It is not clear in the standard if a separate load flow report (Attachment 1) is required for each point of verification, or only for the maximum load, maximum lagging reactive point. Please clarify in the standard.
Response: The GVSDT thanks you for your comment. The GVSDT anticipates that each test point would require a separate Attachment 2 report to be completed.		
Lakeland Electric	Yes	Under the section B. requirements R1, 1.1; it refers us to “attachment - 1” . Under attachment - 1, item 2 - 2.1 it states the following:

Organization	Yes or No	Question 14 Comment
		o Perform verification of real and reactive power capability of all generating units at maximum over excited (lagging) and under-excited (leading) reactive capability at gross real power capability. We would like to propose adding “or to the documented limiting factor of the equipment (generator, voltage regulator, transformer, transmission etc.)”. We want to avoid having to test to the min and max of the capability curve if there is some other limiting factor we can document.
Response: The GVSDT thanks you for your comment. The standard doesn’t require a unit to reach the capability curve value. The capability curve does not reflect all unit limitations that may exist. The limitation that is reached should be recorded on Attachment 2 in the remarks section.		
Exelon	Yes	Nuclear units do not perform under-excited (leading) reactive capability testing due to concerns with unit stability and potential under voltage conditions on internal nuclear plant safety buses that may challenge safe plant operations and could lead to a plant transient or shutdown in accordance with NRC operating license. Performance of reactive capability tests cannot challenge nuclear plant NRC licensee Technical Specification voltage limit requirements. Exelon strongly suggests that the SDT coordinate this revised Standard with the Nuclear Regulatory Commission (NRC) to preclude any challenges to the licensing basis of any of the nuclear generating facilities. Suggest that all exceptions to test performance criteria be pulled forward into body of the Standard. Additional comments for MOD-025-2 Attachment 1 o Step 2.3 - remove reference to "rated real power" - the reactive power test is conducted as a stand alone test using the attainable real power (which is generally governed by ambient conditions at the time of the test). o Step 2.4 - remove reference to "over-excited reactive capability" - the over-excited test is conducted for a minimum of 1 hour o Step 3.4 - remove reference to "correction factor: - this applies to correcting MW as part of the MOD-024 test. Reactive power is tested at the attainable MWe.
Response: The GVSDT thanks you for your comment. **(1) Response: If a nuclear plant has under-excited capability it should be tested within the unit’s capability and declared safety margins. The standard does not require challenging unit capabilities. The following statement was added to Note 1 of Attachment 1 for clarity, “Auxiliary bus voltage limits should be observed”.**		

Organization	Yes or No	Question 14 Comment
(2) Response: The GVSDT has added language to Attachment 1, Section 2.1 to clarify the required full Load test points. **(3) Response: Refer to Attachment 1, Section 2.3. The one-hour over-excited reactive capability test is performed only for the rated Real Power capability test. Step 2.4 refers to verification at minimum Real Power capability.** **(4) Response: The GVSDT modified the language in Attachment 1, Section, 3.4 for clarity and "correction factor" was removed.**		
Georgia Transmission Corporation	Yes	Regarding reactive capability, the SDT has recognized that this standard will not meet the purpose "To ensure that planning entities have accurate generator Real and Reactive Power capability data when assessing Bulk Electric System (BES) reliability." Should the standard and/or purpose be adjusted to where they match? Reactive capability cannot be determined, generally, without disturbances to the system. Long-term fault recorders could be installed at all generator high-side buses and verification of generation to any eventual disturbances could be used to get a better picture of the plants reactive power capability. R1.3 is unclear we propose: Submit the recorded data to its Transmission Planner within 90 calendar days of the date the data is recorded.
Response: The GVSDT thanks you for your comment. **(1) Response: The goal of this standard is to model steady state capability of generators and synchronous condensers. Therefore, the standard requirements meet the stated purpose.** **(2) Response: Requirement R1, Part 1.3 has been revised for clarity and the revised language is:** **"1.3. Submit to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data."**		
Wisconsin Electric	Yes	Attachment 1, 2.1 and 2.2: It would be more reasonable to allow for some small variation in real power level around the rated gross real power output and minimum real power outputs, perhaps within +/- 5 percent of these values. This would allow for variability in coal conditions, system voltages, etc. Also, the requirement in 2.1 for 90 percent of wind turbines online may be impractical in many cases. A lower value such as 75 percent may be more reasonable.
Response: The GVSDT thanks you for your comment. Reference Attachment 1, 2.1. Some drift in Load is expected and language was added to account for less than 90 percent of wind turbines being on line.		
Great River Energy	Yes	Please see comments submitted by the MRO NSRF for question #14

Organization	Yes or No	Question 14 Comment
Response: Please see response to above question.		
Constellation Power Generation	Yes	CPG is concerned with the general wording of Attachment 1 as the verbiage is not auditable. For example, Item 2.1 states "Maintain as steady as possible Real and Reactive Power output during verification." The term "steady as possible" is extremely subjective and open to a multitude of interpretations. From a technical perspective, item 3.3 is not auditable because it is assuming that the voltages and the high and low side of the GSU are metered. This is usually not the case. A statement allowing for an entity to report on the requested metered points based on their configuration and allowing for some points to not be answered would be preferable. Likewise, Attachment 2 would require a similar statement.
Response: The GVSDT thanks you for your comment. **(1) Response: The GVSDT has revised Attachment 1, 2.1 for clarity. The revised language states:** "Maintain as steady as practical Real and Reactive Power output during verifications (i.e. make no purposeful Load changes and do not have the unit in automatic Load control)." (2) **Response: The GVSDT has revised Attachment 1, 3.3 for clarity. It is anticipated that some non- metered values would need to be calculated.**		
ISO New England	Yes	1. Effective Dates: This proposal is not well explained and very well may not work. Some concerns that arise: (a) For those GOs that have units in multiple control areas, are they supposed to apply the Implementation Plan for their entire fleet or for their fleet on a per Region basis? This same issue can apply to TOs which may be in multiple areas. This seems impossible to track and may leave some areas without any verification for 5 years after the standard has been approved. The Transmission Operator should be given the discretion to require and approve a test schedule within its area. (b) For those GOs with only one or two facilities in a region, how will the 5-year implementation plan work? Will the GO with one facility in a region have 5 years to implement (i.e., the 100% rule would not "kick" in until 5 years out, or will the GO with one facility in a region have only 1 year to implement (since 20% of 1 unit would arguably capture the unit). 2. R1.2 and 2.2 All entities should use the same submittal form. Please delete the option for a Generator Owner to develop its own form. **3.** R1.3... 90 days is too long for reporting data. Recommend 30 days for providing verification data.

Organization	Yes or No	Question 14 Comment
		4. VSL for R2 should mirror VSL for R1. Specifically R2 doesn't mention submitting >120 days as R1 does. 5. Attachment 1: 1. specify that the AVR must be in service and in automatic controlling voltage if required by the TOP 6. 2. If AVR is not required by the TOP, does the unit still have to test? Under the VAR-001 standard an entity may be exempted by the Transmission Operator from having a functional AVR. Under such an exemption the need for testing should not be required. 7. Attachment 2: move the check boxes to the top so that that someone looking at form knows immediately what type of audit was performed. 8. o There should be VSLs in regards to going more than 66 months between verifications. 9. o Periodicity should be captured in Requirements, not in the Attachment 10. If each test is done on different days, does each test have its own verification date? 11. Please clarify what footnote 1 of Attachment 1 is intended to describe with "normal" with respect to the unit's normal expected maximum Real Power at the time of the verification. 12. o Attachment 1, Section 2.1 states that during wind turbine and photovoltaic verification, 90% must be on line. This should read "with AT LEAST ninety percent of the..."
Response: The GVSDT thanks you for your comment. **(1) Response: The GVSDT believes the GO/TO, as applicable, is responsible to coordinate verification of all units with their TOP(s) within the verification period identified in the standard. The Implementation Plan calls for various percentages of assets to be verified in each year over the phase-in period.** **(2) Response: The GVSDT created a sample form, Attachment 2. This form should be modified for each unit.** **(3) Response: Because this data is for the long-term planning horizon, the GVSDT believes the timeframe specified is appropriate.** **(4) Response: The VSLs have been revised and now include a Severe VSL as proposed for Requirement R2 (R3 in the revised standard).**		

Organization	Yes or No	Question 14 Comment
(5) Response: Voltage control mode is required by VAR-001. **(6) Response: Attachment 1, 2 states the voltage regulator must in automatic mode for the Reactive Power capability test. If automatic control is not available and is not expected to be available any time soon, the test should be conducted but with caution relative to the generator limits.** **(7) Response: The GVSDT liked the suggestion and has made the change.** **(8) Response: The severe VSL applies in this situation.** **(9) Response: The GVSDT believes the current format is clear. The attachments are an extension of the requirements.** **(10) Response: Yes.** **(11) Response: If a generator goes to full output (not emergency output), that would be considered "normal." This is most likely the declared output of this unit.** **(12) Response: The GVSDT agrees and has modified attachment language to use the proposed, "at least 90 percent".**		
Independent Electricity System Operator	Yes	1. In our previous comments, we raised a concern over the detailed requirements in Attachment 1 which in our view are overly prescriptive. Specifically, the requirements listed in Item 3 of Attachment 1 are too detailed, and some of the items listed in 3.1 to 3.6 are not needed or relevant to the provision of verified data for modeling or BES reliability assessment, but they create unnecessary administrative burden. For example, what would be the use of voltage at the high side of the generator step-up and/or system interconnection transformer(s) and the tap settings of these transformers in the application of the recorded real and reactive capabilities to modeling and reliability assessments? And what would be the required actions if the voltage levels and/or the transformer tap setting in the load flow model or in real time are different from the reported values? Imposing the reporting requirement without a clear statement of the intended use, with justification, is unnecessary and should be dropped. Further, we request clarification regarding the phrase "at the end of the verification period" in 3.1 and 3.3? Does it mean the time when the verification test ends, i.e. at the end of the 1-hour period referred to in Attachment 1, bullet 2.3? 2. If the verification is provided by operational data, what would constitute "the end of the verification period"? 3. We believe Attachment 1 needs only to specify the sustainability (Items 1 and 2) and the periodicity (Item 5). We also respectfully disagree with the SDT's response to our previous comments on Attachment 1. The SDT's view that (excerpt from Comment Report) "The SDT believes that attachment one does not contain requirements but provides clarity to the Requirements of the Standard." is incorrect since it is clearly indicated in Requirement 1.1 to "Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with

Organization	Yes or No	Question 14 Comment
		Attachment 1."According to the general rule for NERC standards, an attachment is a part of the standard that must be complied with, and hence any items contained in an attachment are mandatory requirements. With that understanding and with the way Attachment 1 is included in Requirement 1.1 that the items in Attachment 1 are not there for clarity but are requirements that must be complied with, we urge the SDT to remove the entire Item 3 from Attachment 1 as the information required in that item does not add to the intended use of the verified data. 4. We do not have the same concern over Attachment 2 since it is made clear in Requirement 2.2 and in the Attachment itself that use of other forms is acceptable and hence use of the diagram is not mandatory. In Attachment 1, step 2.4 seems to be inconsistent. For the over-excited check, record should be taken at min. and max. real power output (i.e. it should state... data required in 2.1 and 2.2.)The table in Attachment 2 should be improved to match data to be recorded in Attachment 1 (i.e. there should be two columns for MVAR to record lagging and leading reactive power for a given MW). 5. MOD-025 Attachment 1 bullets 2.1 and 2.2 should stipulate that Generator Owners and Transmission Owners conduct verification at generator terminal voltages as close as possible to rated terminal voltage. Finally, the standard should use SI units (e.g. active power not real power, Mvar not MVAR).

Response:

Response: The GVSDT thanks you for your comments. The GVSDT believes that the data requested in Attachment 1, Paragraph 3 reflects the data needed to properly verify the unit/Facility. Most of this data was included in the FERC Directives.

(1) Response: Yes, "at the end of the verification period" means at the end of the one-hour period referred to in Attachment 1, Section 2.3.

(2) Response: For operational data, "the end of the verification period" would be the end of the one hour test, the whole hour of which should be recorded.

(3) Response: The GVSDT agrees that items contained in the attachments are mandatory. The GVSDT also believes that the data required in Attachment 1, Section 3 is necessary for meaningful evaluation of Real Power capability or Reactive Power capability.

(4) Response: Attachment 1, Section 2.4 refers to when the data should be taken, i.e., the data can be taken immediately for the low load over-excited and any under-excited tests. The full load over-excited test is run for one hour and is included in Attachment 1, Section 2.3.

(5) Response: The GVSDT thanks you for your comments. The GVSDT feels that allowing a full range of voltage, within equipment limitations and allowed by the TOP would provide a more reasonable expectation of demonstrating the unit/Facility capability over a greater portion of the D-Curve. Testing "as close as possible" to generator terminal voltage would be too subjective and not allow adequate range on many units. The GVSDT believes that the use of Real and Reactive power is appropriate for this standard. The term "MVAR" has been revised to "Mvar" throughout the

Organization	Yes or No	Question 14 Comment
standard.		
Indeck Energy Services	Yes	For a plant with fewer than 5 units, implementation should be at the point that the unit finally satisfies the requirement, stated differently, a single unit station would comply at the 5 year point, not at the 1 year point. Why should multiple unit plants be given more time than single unit plants. If having the units done in 5 years meets the BPS reliability need, then it should apply this alternative way. If BPS reliability needs compliance in 1 year, then all should comply.
Response: The GVSDT thanks you for your comment. The implementation is phased in over five years because testing all units in the same year would be impractical. Since the requirement requires testing only once every five years, it is reasonable to space unit testing.		
Indiana Municipal Power Agency	Yes	IMPA believes that the first sentence of requirement 2.1. does not read correctly in the sense that it is requiring the verification of Real Power Capability at maximum over-excited and under-excited reactive capability at rated gross Real Power Capability. This sentence would make sense if Real was removed at the beginning of the sentence and read "Perform verification of Reactive Power capability of all generating...". Requirement 2.2 covers real power testing requirements. Since Real power needs to be removed from 2.1 then requirement 2.3 needs to have the requirement 2.2 added to it to cover the Real power testing time.
Response: The GVSDT thanks you for your comment. The language of Attachment 1, Section 2.1 has been revised for clarity. The revised language is shown below: **"2.1. Perform verification of Real Power capability, Reactive Power capability over-excited (lagging) and Reactive Power capability under-excited (leading) of all generating units at the generating unit's normal (not emergency) expected maximum Real Power at the time of the verifications. Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of reactive capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, the Generator Owner must document the reasons it was unable to meet the threshold and test to the full capability at the time of the test. The Generator Owner shall retest the Facility within six months of being able to reach the 90 percent threshold. Maintain as steady as practical Real and Reactive Power output during verifications."**		
Los Angeles Department of Water and Power	Yes	MOD-025 Attachment 1 Sec. 2.1During normal operations, it is typical to have many wind and solar units not working due to equipment malfunctions such as faults. How will failures that prevent the testing of 90% of equipment integrate with the standard? MOD-025 Attachment 1 Sec. 4Will As-Built Project Drawings suffice for the requirement? The development of

Organization	Yes or No	Question 14 Comment
		new one-line diagrams for a simplified version could have a significant impact because it will require the support of drafting resources which might not be available potentially delaying the submittals of Models and Data Reports. The requirement of directional arrows for Reactive Power Flows can be superimposed on the As-Built drawings. MOD-025 Attachment 1, Sec. 5From a user's perspective, it would be useful to get some language from the ERO that quantifies and qualifies what type of control system conditions would trigger the need for a new model and data verification, and also to have access to a comprehensive sample of a model and data verification test plan. This would allow the user to better manage its compliance implementation phase.
Response: The GVSDT thanks you for your comment. **(1) Response: The language of Attachment 1, Section 2.1 has been revised to allow flexibility.** **(2) Response: See the example in Attachment 2. A very simple drawing is suggested and should not require significant resources to create. If your existing one-line drawings have the information required they may be used as a basis for this standard.** **(3) Response: Attachment 1, Section 5 refers to any change that would affect the Real Power or Reactive Power capability of the unit and makes no distinction between control system changes or limitations from other equipment that would alter the last verified capability by more than 10 percent and would last for more than six months. Some examples triggering retesting would include GSU replacements, excitation system change outs (replacements, upgrades or parameter changes), turbine rotor replacements, turbine control system change outs (replacements, upgrades or parameter changes). Basically, any change that would be expected to have an effect on the capability.**		
Austin Energy	No	
American Wind Energy Association	No	
Tacoma Power	No	None
APS		being intentionally left blank (no answer to be provided)
Response: The GVSDT thanks you for your comment.		
Dynegy Inc.	No	

Organization	Yes or No	Question 14 Comment
Manitoba Hydro	No	
Response: The GVSDT thanks you for your comment.		
Westar Energy	No	
Response: The GVSDT thanks you for your comment.		
Luminant Power	No	
Salt River Project	No	
Tri-State Generation and Transmission, In.	No	
BC Hydro	No	
Northeast Utilities	No	
Consolidated Edison Co. of NY, Inc.	No	
American Electric Power	No	
Ingleside Cogeneration LP	No	
Wisconsin Public Service Corp	No	
Northeast Power Coordinating Council	No	
Imperial Irrigation District (IID)	No	

Organization	Yes or No	Question 14 Comment
Oncor Electric Delivery Company LLC	No	
Gainesville Regional Utilities	No	