NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Project 2007-09 Generator Verification
MOD-025-2

The Project 2007-09 Generator Verification Standard Drafting Team (GVSDT) thanks all commenters who submitted comments on the proposed revisions to MOD-025-2. The standard was posted for a 30-day public comment period from September 28, 2012 through October 31, 2012. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 48 sets of comments, including comments from approximately 155 different people from approximately 100 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

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

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration of all Comments Received:

There were a number of non-substantive changes made to the standard. Those changes are both explained in the summary comments for each question and in the individual responses to comments under Questions 1, 2, and 3:

In general, the comments indicated that industry is supports Attachment 1 as posted in Draft 3 of MOD-025-2. In response to stakeholder comments several changes were made to provide consistent wording and clarity within and among Attachments 1 and 2.

Based on comments received the GVSDT determined that Note 3 of Attachment 1 added confusion and since it was not vital to Attachment 1 it was removed. Note 3 said "It is desired that the automatic voltage regulator be in service when testing a generator's reactive capability. If an automatic voltage regulator is not installed on the unit to be tested, or is not available at the time of the test, exercise extra caution not to exceed the operating limits of the generator. "

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

Clarifications were made in the standard regarding treatment of units in long term reserve shutdown, coordination with the Transmission Operator for staged testing, and collection of data for ambient condition corrections. The GVSDT also clarified that the first verification must be a staged test.

The industry is generally supportive of the VSLs. As a result of stakeholder comments, clarifying edits were made to VSLs for Requirements R2 and R3 to provide wording consistent with the VSL for Requirement R1– this is non-substantive because the level was not changed.

The following note was added to the Effective Date section for clarity – "The verification percentage above is based on the number of applicable units owned."

As a result of stakeholder comment, clarification was added to the Effective Date section regarding regulatory approval in Canada.

In response to stakeholder comments, the following non-substantive changes were made in Attachment 2:

1) A clarifying phrase was added to the header in the "last verification" column

2) A bullet point in the Summary of Verification that was intended to be removed during the last comment cycle and was not, has now been removed

3) The tap setting and voltage ratio wording were made consistent throughout Attachments 1 and 2.

Spelling and punctuation corrections:

- Footnote 2 – Corrected capitalization in Wind farm verification
- VSL Requirement R1 moderate - removed period
- Attachment 1
    - Periodicity for conducting a new verification - second to last paragraph corrected capitalization of the word "load"
    - Verification specification for applicability Facilities – Changed 'shall' to 'will'
    - 4.1 - corrected capitalization of the word "load"
    - Renumbered Notes 4 and 5 due to deletion of Note 3
- Attachment 2 – Added missing arrow at point "F"

Minority Views:

- A minority of commenters requested a periodicity greater than five years. The GVSDT believes that the verification periodicity for Real Power and Reactive Power capability is appropriate at five year intervals and was addressed in previous comment periods. The GVSDT believes that stakeholder consensus has been achieved in this regard.

- A few entities submitted comments with regard to the use of engineering analysis in place of staged testing similar to comments submitted during previous postings. The GVSDT explained that engineering analysis could be appropriate in some cases, but not in place of staged testing because engineering analysis will not identify equipment problems and these equipment problems may not show up during normal operations.

- At least one entity suggested that nuclear units should not be required to perform under-excited (leading) reactive capability verification 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 nuclear plant specific NRC operating license.

The GVSDT reaffirmed that challenging the plant's safety systems is not required by this standard. The standard does not require operating beyond plant operating limits.

[SC1]

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

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

Group 1 (Mike Garton, Domion):

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

Group 2 (Stephen J. Berger, PPL Corporation NERC Registered Affiliates):

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

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

		Entities		
4.	Elizabeth A. Davis	PPL EnergyPlus, LLC	MRO	6

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

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

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

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

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

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

				1	2	3	4	5	6	7	8	9	10
5.	Group	Brandy Spraker	Tennessee Valley Authority	X		X		X	X				

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

				1	2	3	4	5	6	7	8	9	10
6.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Burns	Technical Operations	WECC	1

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

2. Chuck Matthews	Transmission Planning	WECC	1
3. Erika Doot	Generation Support	WECC	3, 5, 6

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

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

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	paul haase	Seattle City Light	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. pawel	krupa	WECC	1
2. dana	wheelock	WECC	3
3. hao	li	WECC	4
4. mike	haynes	WECC	5
5. dennis	sismael	WECC	6

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

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

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

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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
11.	Group	Thomas McElhinney	JEA	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ted Hobson		FRCC	1
2.	Garry Baker		FRCC	3
3.	John Babik		FRCC	5

12.	Group	Brenda Hampton	Luminant						X				

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

13.	Group	Jason Marshall	ACES Power Marketing Standards Collaborators						X				

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

14.	Group	Greg Rowland	Duke Energy	X		X		X	X				

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

15.	Group	David Dockery, NERC Reliability Compliance Coordinator	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

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

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren Services Company	SERC	1
2.	James Manning	NCEMC	SERC	1
3.	Jim Kelley	PowerSouth Energy Coop	SERC	1
4.	Philip Kleckley	SC Electric & Gas Co	SERC	1
5.	Bob Jones	Southern Company Service	SERC	1
6.	Pat Huntley	SERC Reliability Corp	SERC	10
7.	David Greene	SERC Reliability Corp	SERC	10
8.	Amir Najafzadeh	SERC Reliability Corp	SERC	10

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17.	Individual	Shammara Hasty	Southern Company	X		X		X	X				
18.	Individual	David Thorne	Pepco Holdings Inc and Affiliates	X		X							
19.	Individual	ryan millard	pacificorp	X		X		X	X				
20.	Individual	Brian Bejcek	Wolverine Power Supply Cooperative, Inc.	X									
21.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X					
22.	Individual	Jim Watson	Dynegy					X					
23.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
24.	Individual	Lynn Schmidt	NIPSCO	X		X		X	X				
25.	Individual	Cristina Papuc	TransAlta Centralia Generation LLC					X					
26.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
27.	Individual	Winnie Holden	PSEG	X		X		X	X				
28.	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
29.	Individual	Michelle R. D'Antuono	Ingleside Cogeneration LP (Voting entity Occidental Chemical Corporation)					X					
30.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
31.	Individual	Ken Gardner	Alberta Electric System Operator (AESO)		X								
32.	Individual	Thad Ness	American Electric Power	X		X		X	X				
33.	Individual	Michael Falvo	Independent Electricity System Operator		X								
34.	Individual	Wryan Feil	Northeast Utilities	X									
35.	Individual	Brian Evans-Mongeon	Utility Services								X		
36.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
37.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X	X	X	X				
38.	Individual	Scott Berry	Indiana Municipal Power Agency										
39.	Individual	Eric Bakie	Idaho Power Company	X		X							
40.	Individual	John Yale	Chelan PUD					X					
41.	Individual	Robert Casey	Georgia Transmission Corporation	X									
42.	Individual	Maggy Powell	Exelon Corporation and its affiliates	X		X	X	X	X				
43.	Individual	Kirit Shah	Ameren	X		X		X	X				
44.	Individual	Don Jones	Texas Reliability Entity										X
45.	Individual	Martin Kaufman	ExxonMobil Research and Engineering	X				X					
46.	Individual	Tony Kroskey	Brazos Electric Power Cooperative, Inc.	X									
47.	Individual	Russell Noble	Cowlitz PUD			X	X	X					
48.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					

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

Summary Consideration:

Organization	Supporting Comments of "Entity Name"
MEAG Power	Southern Company Services, Inc. - Gen
Liberty Electric Power LLC	NAGF
Indiana Municipal Power Agency	Indiana Municipal Power Agency agrees with the comments submitted by the North American Generator Forum (NAGF)group for MOD-025.
Brazos Electric Power Cooperative, Inc.	ACES Power Marketing
Nebraska Public Power District	MRO NSRF

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

Summary Consideration: In general, the industry is supportive of the revisions made to Attachment 1 in Draft 3. In response to stakeholder comments several changes were made to provide consistent wording and clarity within Attachments 1 and 2. None of these changes is substantive.

Based on comments received the GVSDT determined that Note 3 of Attachment 1 added confusion and since it was not vital to Attachment 1 it was removed. Note 3 said "It is desired that the automatic voltage regulator be in service when testing a generator's reactive capability. If an automatic voltage regulator is not installed on the unit to be tested, or is not available at the time of the test, exercise extra caution not to exceed the operating limits of the generator. "

Clarifications were made in the standard regarding treatment of units in long term reserve shutdown, coordination with the Transmission Operator for staged testing, and collection of data for ambient condition corrections. The GVSDT also clarified that the first verification must be a staged test.

Organization	Yes or No	Question 1 Comment
ACES Power Marketing Standards Collaborators	No	(1) We believe that Attachment 1 is clearer but we still have a few issues that the drafting team should address. In response to our previous comments, the drafting team indicated that a staged test is required prior to the use of operational data. In other words, the first verification must be through a staged test. The response to comments cited a sentence in sub-section 2 of the "Verification specifications for applicable Facilities:" in Attachment one as the reason. Essentially, it says if the previous test was unduly restricted, then the next verification should be a staged test. We do not think this is straight forward. What if there was no test? Could a test that did not occur be called unduly restricted? It would be much clearer for the drafting team to state directly either in Attachment 1, the requirements, the implementation plan or the effective date section that the first test must be a staged test.

Organization	Yes or No	Question 1 Comment
		Response: The SDT agrees and has added clarification to Attachment 1 under item 1 of "Periodicity for conducting a new verification". It now reads: "The first verification for each applicable Facility under this standard must be a staged test." (2) In subsection 3.4 of the "Verification specifications for applicable Facilities:" section of Attachment 1, we disagree with including "Other data as applicable." It is ambiguous, open ended and will only lead to inconsistent enforcement. Who decides what is applicable? The TP? The GO? The auditor? What happens if an auditor decides they believe a piece of data should be included but the TP and GO agree it shouldn't? If the other needed data cannot be enumerated, an open ended statement such as the one discussed here should not be added as a "catch all." This type of statement is unduly burdensome. **Response: We have changed the wording to provide clarification as follows: "Other data as determined to be applicable by the GO to perform corrections for ambient conditions."**
Response: The GVSDT thanks you for your comments. Please see responses above.		
Texas Reliability Entity	No	1) Attachment 1, 2.2.2: We recommend changing the reactive power capability test to be conducted at 95% or higher of the expected maximum Real Power gross output. **Response: Your comment suggests relaxing the standard with no supporting reason. The GVSDT believes that we have reached industry consensus with respect to this aspect of the standard and will not make further revisions** 2) Attachment 1, 2. We disagree with the statement that "...previously staged test that demonstrated at least 50 percent of the Reactive

Organization	Yes or No	Question 1 Comment
		capability shown on the associated thermal capability curve (D-curve). Unless there is a documented system limitation, an accurate test should result in 90% or better of the D-curve, after correction for ambient conditions. **Response: The GVSDT agrees with your comment however the 50% of the D-Curve requirement recognizes that the previously staged test provided the documented limitation that you reference.** 3) Attachment 1, 2.2 does not require wind and photovoltaic "applicable facilities" to verify Reactive Power capability at a minimum Real Power output. The ISO may still have reactive requirement for renewable resources at minimum output levels. If so, the resource should be required to demonstrate and test against those requirements? **Response: The ISO can request additional testing at any time. Defining minimum Real Power from variable generation resources can be problematic. For that reason the GVSDT allows testing variable generation plants at whatever load is available at the time of the test.** 4) Attachment 1, 2.1.1: What is the basis for "one hour?" Attachment 1, 3.1 says to record the value at the end of the verification period. What is the expected value(s) to be provided for the hour of verification (i.e. an instantaneous value, an integrated value, or average value)? Variability in solar and wind turbines may not allow for a full hour. Current ERCOT regional criteria for the Reactive Power leading and lagging test duration is 15-minutes. **Response: The industry has reached a consensus that 1 hour is long enough for a unit to stabilize thermally. The GVSDT recognizes that a variable generation plant may not have constant output for one hour. The instantaneous values at the end of the one hour test are the values expected to be reported.**

Organization	Yes or No	Question 1 Comment
		5) Attachment 1, 3.2: If there is a modified voltage schedule to accommodate the testing, the normal voltage schedule and modified voltage schedule should be recorded. **Response: The voltage schedule recorded should be the one that is in effect at the time of the test. Additional documentation on the voltage schedule should not be required since the TOP issues that voltage schedule.** 6) As written, this Standard will only capture one season and may not facilitate proper use of the data in Planning models. In ERCOT, resource entities currently provide minimum and maximum seasonal capabilities for Fall, Winter, Spring, and Summer. We would suggest that, as a minimum, this Standard should require Real and Reactive capabilities for the Winter and Summer seasons. **Response: Seasonal adjustments are expected to be calculated with the data that is recorded in Attachment 1, 3.4 if requested by the TP.** 7) Attachment 1, section 3: Generator Owner should also include the D-curve with the verification data. For many air-cooled units, the real and reactive capability can vary significantly with ambient temperature. The Transmission Planner needs both the ambient temperature and the D-curve data to verify the validity of the test. **Response: The verifications in MOD-025-2 are intended to demonstrate the capability of the unit that is reported or show limitations to that capability, not necessarily to demonstrate the D-curve.** 8) Attachment 1, 3.4: we suggest re-wording to "... perform corrections to Real Power ***and Reactive Power*** for different ambient conditions..." **Response: Corrections for ambient conditions are intended for Real Power as it can vary substantially for some units.**

Organization	Yes or No	Question 1 Comment
Response: The GVSDT thanks you for your comments. Please see responses above.		
Tennessee Valley Authority	No	1. Att 1, Periodicity for conducting a new verification: 1. For staged verification; recommend changing the allotted time to make a change to 12 months. From Att 1: “... of a change that affects its Real Power or Reactive Power capability by more than 10 percent of the last reported verified capability and is expected to last more than six months” - change to 12 months. Justification is based on the possibility of generator temporary derates lasting more than 6 months due to seasonal conditions, outage schedules, economic dispatch, etc. Twelve months is more realistic. **Response: The GVSDT added the additional six month to perform another verification in order to allow the GO time to do this in a scheduled manner. The GVSDT believes that industry consensus has been achieved with regard to this issue.** 2. Att 1, Periodicity for conducting a new verification: 2. For verification using operational data; recommend changing the allotted time to make a change to 12 months. Att 1: “... discovery that its Real Power or Reactive Power capability has changed by more than 10 percent of the last reported verified capability and is expected to last more than six months” - change to 12 months. Justification is based on the possibility of generator temporary derates lasting more than 6 months due to seasonal conditions, outage schedules, economic dispatch, etc. Twelve months is more realistic. **Response: The GVSDT added the additional six month to perform another verification in order to allow the GO time to do this in a scheduled manner. The GVSDT believes that industry consensus has been achieved with regard to this issue.**

Organization	Yes or No	Question 1 Comment
		3. Att 1, Periodicity for conducting a new verification:, 1 For Staged verification; and 2. For verification using operational data; both steps require verification at least every five years. Recommend verification periodicity equal to PRC-005-2 Draft, Table 1-1, Component Type - Protective Relay, Maximum Maintenance Interval, “6 calendar years.” Justification is to coordinate protective system relay testing during plant outages with the real and reactive power testing that can be performed during outage shut-down or start-up. **Response: The GVSDT believes that industry consensus has been achieved with regard to a five years testing cycle.** 4. Attachment 1, 3.6, add “voltage ration and,” as follows: The existing GSU and/or system interconnection transformer(s) voltage ration and tap setting. Justification is to be consistent between Attachment 1 and Attachment 2. Current Attachment 1, 3.6, identifies “transformer(s) tap setting”; Attachment 2, had data entries for “Voltage Ratio.” Both values are legitimate transformer parameters. **Response: The GVSDT agrees and has corrected the oversight adding “voltage ratio” to Attachment 1, 3.6.** 5. Recommend Att 1, 4., be titled as “Record the following auxiliary load information:” Justification is that the current “step 4” is more of a substep to this new “step 4” description. **Response: The GVSDT disagrees and considers Attachment 1, Item 4 to direct the development of a simplified key one-line diagram as stated.** 6. Recommend Att 1, 4., current step text be moved to a substep 4.1, “Develop a simplified key one-line diagram ... “ Justification is that this step is similar to the current “steps 4.1 and 4.2” **Response: The GVSDT has renumbered Attachment 1, 4.2 as 5 to**

Organization	Yes or No	Question 1 Comment
		provide clarity. 7. Recommend renumbering steps “4.1 to 4.2” and “4.2 to 4.3.” Justification is to change the current “step 4 to 4.1.” See items 4 and 5, above. **Response: See responses to comments 4 and 5 above.** 8. Recommend changing the current “step 4.2 / recommended step 4.3” to read as follows:”If an adjustment is requested by the TP, then develop the relationship between test conditions and generator output so that the amount of Real Power that can be expected to be delivered can be determined from a generator at different conditions, such as peak summer conditions [remove can be determined]... “ Justification is to reword for clarity. **Response: The GVSDT has revised this sentence for clarity as: “If an adjustment is requested by the TP, then develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator can be determined at different conditions, such as peak summer conditions.**
Response: The GVSDT thanks you for your comments. Please see responses above.		
Exelon Corporation and its affiliates	No	1) Attachment 1 (general comment):Exelon appreciates the addition by the GVSDT of the exclusion that nuclear units are not required to perform Reactive Power verification at minimum Real Power output (Attachment 1 Section 2.2.3); however, as stated in the previous comments, Exelon still is concerned that nuclear units should not be required to perform under-excited (leading) reactive capability verification 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 nuclear

Organization	Yes or No	Question 1 Comment
		plant specific NRC operating license. In response to Exelon's comments in the 9-27-12 Consideration of Comments, the GVSDT states that they "disagree with not requiring a verification to define the unit's reactive capability" and further states that they are "aware of nuclear units that have been safely tested to their leading power factor limits." Although the GVSDT may purport that it is safe to perform such testing there is not one unique design for a nuclear generating unit in the NERC Regional Entities. Exelon continues to believe that there should be a provision in the Standard to allow for such an exemption based on considerations for nuclear unit regulatory, unit stability or other potential equipment restrictions. To address the concern that the GVSDT has related to providing a blanket exemption for nuclear units, Exelon suggests that such an exemption must be justified, documented in writing, and accepted by the Transmission Planner. Exelon suggests that a new note be added to Attachment 1 as follows:"If a unit is restricted due to other regulatory, unit stability, plant operating procedures, or other potential equipment restrictions then it should be reported with no leading capability, or the minimum lagging capability at which it can operate. A generating unit with such a restriction must be justified, documented in writing and accepted by the Transmission Planner." **Response: The GVSDT reaffirms, as stated in the previous response to comments, that challenging the plant's safety systems is not required by this standard.** 2) Periodicity for conducting a new verification: Attachment 1 Section related to the periodicity for conducting a new verification (page 15 of 22) second paragraph states: "The test shall be scheduled at a time advantageous for the unit being verified to demonstrate its Reactive Power capabilities while the Transmission Operator takes measure to maintain the plant's system bus voltage at the scheduled value or within acceptable tolerance of the scheduled value." Experience shows that maintaining the

Organization	Yes or No	Question 1 Comment
		plant's substation bus voltage within the scheduled voltage range at some arbitrary value is often inadequate to allow maximum VAR output during staged Reactive Capability testing. In such cases the system operator would need to adjust the substation voltage, potentially close to a schedule limit. Exelon suggests that the sentence be revised as follows: "The test shall be scheduled at a time advantageous for the unit being verified to demonstrate its Reactive Power capabilities while the Transmission Operator takes measure to coordinate with the Generator Operator to adjust the plants substation bus voltage as required to accommodate the desired reactive output." **Response: The GVSDT believes the standard, as worded allows for adjustments by the TOP but only to the limits acceptable to the TOP.**
Response: The GVSDT thanks you for your comments. Please see responses above.		
Associated Electric Cooperative, Inc. - JRO00088	No	Attachment 1, Parts 2.2.1 and 2.2.2, AECI does appreciate adequate Attachment 1 allowances for voltage-schedule restrictive operating conditions, so that actual Maximum and Minimum reactive capabilities that simply cannot be attained, are not required, as acknowledged per Notes 1 & 2. However we do question the value to industry, beyond initial testing per this standard, of the 5-year retesting and believe this Requirement will eventually be removed unless redrafted per responsible entities' internal controls program expectations. We do however agree with the requirement to retest when unit conditions change sufficiently to warrant retesting.
Response: The GVSDT thanks you for your comments. Periodic verification is necessary for discovering the equipment limitations that impact the unit MW or MVAR capabilities. The GVSDT believes that industry consensus has been achieved regarding the 5 year verification cycle.		

Organization	Yes or No	Question 1 Comment
Seattle City Light	No	Attachment 1, Section 2.1 explicitly states to run each unit at maximum real power and lagging reactive power for a minimum of one hour. Due to constraints of the load, water flow, or other operational characteristics such as generators' thermal limits this is typically not possible.
Response: The GVSDT thanks you for your comments. The generator's thermal limits should not adversely restrict a unit's capability verification. If your reference to water flow indicates the units in question are hydro units then Attachment 1, Section 2.1.2 applies and the load required is only that which is available at the time of the test.		
Cowlitz PUD	No	Cowlitz supports the comments developed by the NAGF SRT: 1. The 90-day limit for historical data in R1.2 and R2.2 conflicts with the statement at the bottom of p.15 that "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...." It is also unclear how the day on which verification data are collected can differ at all from the verification date, much less by two years. **Response: The GVSDT does not see a conflict because R1.2, R2.2 and R3.2 state that you have 90 calendar days from the date the data is selected for submission of the data to the Transmission Planner. The two year limit in Attachment 1 refers to how far back in time you can go when you select operational data.** 2. The semantics regarding applicability should be made more consistent. The criterion, "Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System," in para. 4.2.3 appears to state that a station with two 500 MW NERC-registered fossil units and a standby, non-NERC-registered10 MW diesel genset connecting to the 13.2 kV bus, for example, needs testing only for the large units because the diesel is not part of the NERC-defined Facility. Para. 1 at the bottom of p.15 appears to take a contradictory

Organization	Yes or No	Question 1 Comment
		position, however, by saying that “For generating 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.” This would be better stated as, that “For generating units of 20 MVA or less that are included as part of a Facility greater than 75 MVA in aggregate, record data either on an individual unit basis or as a group.” **Response: Your example of a 10 MW diesel genset connected to a 13.2 kV bus would not be applicable because it is not directly connected to the BES nor is it a registered unit. There is no conflict between the Applicability Section and what is on page 15 since page 15 is only Verification specifications for what is found in the Applicability Section.** 3. Applying on p.16 an “unduly restricted” classification to reactive power verification results that fall short of 50% of the thermal capability curve (D-curve) constitutes a technical error that is fatal to the approvability of MOD-025-2 in its present form. The D-curve deals only with a single characteristic (temperature) of a single component (generator), and the reactive capability of a generation unit system is generally set by other factors. Lagging PF is frequently restricted to less than 50% of the D-curve value due to variation of aux bus voltages beyond the IEEE-recommended range of +/- 5% for normal operation, and it is not uncommon for stability issues to preclude any leading-PF operation (nuclear units in particular never operate at leading PF). Potential lack of leading capability is acknowledged in Note 4 of Att. 1, but contradicted by the p.16 references discussed above. All explicit and implied connections in the draft standard between the expectable reactive power capability and the generator OEM D-curve should be expunged. **Response: The generator D-Curve is recognized as the absolute maximum achievable reactive capability. The reference to 50% of the D-curve is an acceptability criterion for using operational data in lieu**

Organization	Yes or No	Question 1 Comment
		of a staged test. 4. Note 1 of Att. 1 (pp. 17-18) is inaccurate and should be deleted. The limitations described in comment #3 above are not related to transmission system conditions. Our concerns are amplified by the statement, “Observe auxiliary bus voltage limits,” in Note 1 from the previously-voted-on version of MOD-025-2 having been deleted from the present draft. Is it the SDT’s intent that units should import and export reactive power to the generator OEM D-curve regardless of whether or not there is risk of tripping due to aux bus dropout? Doing so would constitute an inacceptable operational practice. **Response: The GVSDT disagrees and believes you may have misinterpreted the standard relative to reactive capability testing and the primary reason for not reaching the D-curve is likely due to system conditions. The GVSDT has repeatedly commented and clearly stated in the standard that safe unit limits should not be challenged to perform this testing. Safe limits should be determined by the GO and testing should be stopped short of those limits and the reasons for stopping the test reported.** 5. Note 2 should be deleted as well (“While not required by the standard, it is desirable to perform engineering analyses to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification....”) since there is no quantitative indication of what these other conditions should be or what such an analysis would mean. The line, “The recorded Mvar values were adjusted to rated generator voltage, where applicable,” on P.21 should also be deleted. **Response: The standard does not require engineering analysis and its use is completely at the option of the Generator Owner.**

Organization	Yes or No	Question 1 Comment
		The GVSDT agreed after the previous posting in the Consideration of comments to remove this point ("The recorded MVAR values were adjusted to rated generator voltage, where applicable.") from Attachment 2. We apologize that it did not get removed from the standard and have removed it 6. Clarification is needed regarding the requirement in para. 2.1 of Att. 1 to verify capability, "at the applicable Facilities' normal (not emergency) expected maximum Real Power output at the time of the verifications." It is understood that a unit typically running for example at 720MW in the summer and 740 in the winter could be reported at either value, depending on when the verification was performed; but the term "normal maximum" is inherently an oxymoron, given the dictionary definitions of "normal" as meaning standard, usual, typical, etc. and "maximum" as representing an extreme condition. Para. 2.1 should be changed to read, "within the Facilities' normal (not emergency) range of full load Real Power output at the time of the verifications," to indicate that readings within the dotted lines in the graph below are what's wanted, not the heavy, solid line. Note that normal power is never a single value, it is a range. It would be helpful to include a diagram on the subject, along with any statistical criteria involved in defining NERC's concept of the normal range. **Response: The GVSDT has made changes for clarity of this language several times. We believe that there is now consensus for this language and have no plans for further changes.** 7. The statement on p.15 that, "It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing...," should be expunged. A considerable operational period must be reviewed to determine what the normal full-load real power range is, as explained in comment #4 above, and it is impossible to go back in time and insert a VAR

Organization	Yes or No	Question 1 Comment
		test. **Response: The suggestion to perform the testing at the same time was meant for staged testing only if desired by the GO. It is not a requirement for either operational data or staged testing to do both the Reactive Power and Real Power test at the same time.** 8. It would be helpful to state any coordination of units within a plant that is required or preferred for VAR testing. Running for example a three-unit plant with all units exporting MVARs together, then all importing together, will produce more conservative reactive power capabilities (i.e. the aux bus limits will sooner be encountered) than is the case for testing units one at a time with the other two under normal operation. Pull-together/push-together is the more realistic approach, however, for simulating the response of the plant to a Disturbance of the BES. **Response: It is envisioned that coordination of units within a plant would be necessary to perform reactive capability testing as those other units would be part of the reactive resources needed for optimal testing. It is not within the scope of this standard to analyze each plant for the best test configuration. The GVSDT suggests discussing optimal testing configurations with your TP. Your comment that states in part "….for simulating the response of the plant to Disturbance of the BES." Indicates possible confusion over this standard and MOD-026.** 9. The reference to "maximum Real Power" in para. 2.2.2 of Att. 1 should be changed to match the terminology in para. 2.1, after modification per comment #6 above. **Response: Attachment 1, 2.1 describes the maximum Real Power output for both Real Power and Reactive Power capability testing. Attachment 1, 2.2.2 only provides the time needed before recording the data for the leading reactive power test at maximum real power.**

Organization	Yes or No	Question 1 Comment
		The GVSDT does not feel Attachment 1, 2.1 needs to be restated in Attachment 1, 2.2.2. 10. The requirement in para. 3.4 of Att. 1 that one record, "The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires to perform corrections to Real Power for different ambient conditions," are incomprehensible. It appears to indicate that in some cases ('if applicable") the GO may require that ambient corrections be performed, and in other cases they won't; but there is no indication when and if such calculations are mandatory, and there is no hint as to the reference conditions that GOs are supposed to correct-to. **Response: The hint is found in Attachment 1, 4.2 which states: "If an adjustment is requested by the TP, then develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later."** 11. Para. 4 of Att.1 should state that the simplified key one-line diagram need be no more detailed than that shown in Att. 2. Development of diagrams showing all aux transformers and real and reactive power flows would be unduly burdensome, and the wording of Att. 2 indicates that such a level of detail is not intended. **Response: The format used should provide information comparable to that provided in Attachment 2 as stated in Requirements R1, R2 and R3. The GVSDT feels the directions are clear as currently drafted.** 12. GSU losses should have a separate line in Att. 2, since they are not specifically a tertiary load (item C in the Att. 2 diagram).

Organization	Yes or No	Question 1 Comment
		Response: The GVSDT believes that adequate data is recorded in Attachment 2 to determine gross and net Real or Reactive Power Capability as stated in the Purpose of the standard. 13. MOD-025 should not require "staged testing" without option. Staged testing should only be required if requested under TOP-002-2b R13. This will ensure the appropriate system conditions exist to support the testing (coordinated by the TOP and RC). This eliminates the GO from being required to perform testing that cannot be supported by the TOP and RC. Industry experience has shown that verification of the true reactive limits via staged testing is typically not possible due to transmission system constraints. Due to these constraints, an option to use engineering analysis for validation should be allowed by this standard. While the standard could allow staged testing as an option, we believe that staged testing should only be considered when there is a demonstrated need for the testing. **Response: TOP-002-2.1b covers real-time and near-real-time studies. It is believed that the TOP-002-2.1b, Requirement R13 is intended for verification of units that do not appear to be meeting the stated capabilities of the unit. MOD-025-2 is Real Power and Reactive Power verification for BES units for long range planning. Reasons for staged or operational testing requirements have been well documented in previous consideration of comments documents.** 14. We do not see significant value in a 5-year re-verification cycle through staged testing. We believe a periodic confirmation that the previously verified MW and MVAR capabilities are still valid does have value. Re-verification should only be necessary when there is a long term configuration change, a major equipment modification, or equipment problems that impact the unit MW or MVAR capabilities. Possible equipment problems are being used as reason by some for wanting staged testing and periodic re-verification. Equipment problems that could limit

Organization	Yes or No	Question 1 Comment
		real and reactive power capability generally manifest themselves during normal operation. These are appropriately addressed via normal operational reporting to satisfy requirements in TOP-002-2.1b and VAR-002-2b and are corrected through normal maintenance practices. Therefore, we do not agree that concerns for equipment problems justify periodic testing of every generator in the BES. Furthermore, that approach will subject the BES to a constant state of testing and off-normal operational conditions that we believe could actually prove to be detrimental to BES reliability. **Response: The GVSDT disagrees that "Equipment problems that could limit real and reactive power capability generally manifest themselves during normal operation." The GVSDT believes that the recent ballot results and comments show that industry consensus has been achieved. The GVSDT also disagrees that periodic testing within normal capability ranges would be detrimental to the BES reliability.**
Response: The GVSDT thanks you for your comments. Please see responses above.		
Duke Energy	No	Delete Note 3 on page 18 of the clean version, and delete the reference to Note 3 located on page 15 under "Verification specifications for applicable Facilities: #2". If a unit is equipped with AVR, the test must be conducted with the AVR in service.
Response: The GVSDT thanks you for your comments. The GVSDT agrees with this clarification and has revised the standard accordingly.		
Manitoba Hydro	No	General Comments - There is reference to certain actions that would be 'desirable' although not strictly required by the standard. This type of language can be problematic if the entity is held to this, or asked to explain why they did not meet the 'desirable' level.

Organization	Yes or No	Question 1 Comment
		Response: The GVSDT only found one use of the word "desirable" in the standard and it is in Note 2 of Attachment 1. The GVSDT believes that this language is appropriate and that stakeholder consensus has been achieved on this note. There appear to be requirements embedded in the attachment, and there should be no requirements here. For example, the word "shall" should be removed (since it implies a requirement) from (i) page 15 (clean version) "If the Reactive Power capability is verified through test, the Generator Owner shall schedule the test with its Transmission Operator. The test shall be scheduled . . . . ." and (ii) page 16 " . . . then the next verification shall be by another staged test, not operational data:" **Response: The language in these instances was revised to remove the use of "shall".** Another example which sounds like a requirement is on page 17 "Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later." **Response: The language provides instruction regarding the adjustments requested by the Transmission Planner. The GVSDT believes that consensus has been achieved for this language.** Additionally, in 4.2 (i) "TP" should be expanded to Transmission Planner and (ii) the first sentence is worded poorly and should be clarified. **Response: This was corrected as noted.** Section 2.1 - Manitoba Hydro recommends removing the words "over excited" and replacing the words "normal (not emergency)" with "nominal". **Response: The language used here has been revised several times per**

Organization	Yes or No	Question 1 Comment
		stakeholder comments. The GVSDT believes that the consensus of stakeholders is to use these terms. Section 3.7 - “(real or reactive)” should be changed to “(real and reactive)”. **Response: The GVSDT disagrees because the verification may not be for both Real and Reactive Power. The standard allows for independent verifications.** Page 15 (clean version) - The word “Load” should not be capitalized. **Response: The GVSDT agrees and has made the correction.** Page 17 (clean version), Note 1 - Manitoba Hydro suggests replacing ‘improper tap settings’ in Note 1 which reads “...such as rotor thermal instability, improper tap settings,...” with “improper voltage ratios”. **Response: The GVSDT revised item 3.6 to add “voltage ratio” based on another stakeholder comment. We have revised Note 1 to add “voltage ratio” as well.** Page 18 (clean version), Note 5 - Manitoba Hydro suggests removing Note 5 which reads “Synchronous Condensers only need to be tested at two points (one over-excited point and one under-excited point) since they have no Real Power output.” Such descriptive wording is not required in a standard and should be left for reference books. **Response: The intent of Note 4 (formerly Note 5) is simply to clarify the testing required for synchronous condensers.**
Response: The GVSDT thanks you for your comments. Please see responses above.		
pacificorp	No	PacifiCorp does not support the minimum one hour hold requirement for verifying a generating unit’s maximum real power and lagging reactive power in Section 2.1.1 of Attachment 1. The one hour hold is excessive and fails to correlate to how a machine responds to a system event that

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td></td><td></td><td>only lasts for a few minutes. The one hour requirement also puts unnecessary stress on plant equipment and directly contradicts the WECC Synchronous Machine Reactive Limits Verification Guideline that recommends holding a unit for a minimum of 15 minutes. PacifiCorp has followed this guideline since it was approved in 1996, and recommends this same standard to be applied in Attachment 1.</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comments. The industry has reached a consensus that 1 hour is long enough for a unit to stabilize thermally. The verifications performed under this standard do not relate to system events (as opposed to MOD-026-1 and MOD-027-1) and are intended to provide “accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability” as per the purpose statement. The GVSDT does not believe that there is a conflict with WECC guidelines as they are for a “minimum of 15 minutes”.</td></tr>
<tr><td>Dynegy</td><td>No</td><td>Recommend deleting the requirement in Attachment 1 section 2.2.1 to verify reactive power at minimum load. This puts the unit in an unstable condition and then stresses it by varying reactive power leading to the increased likelihood of a unit trip.</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comments. No test should be run that makes the unit unstable. The GVSDT suggests that minimum load be verified prior to performing any testing to avoid unit instability. The SDT is responding to FERC directives as part of the revisions of this standard. In one of the FERC directives (Order 693, Paragraph 1321) testing at multiple points was required. The standard does not require any testing that would violate any equipment operating limits or lead to equipment damage.</td></tr>
<tr><td>PPL Corporation NERC Registered Affiliates</td><td>No</td><td>1)The 90-day limit for historical data in R1.2 and R2.2 conflicts with the statement at the bottom of p.15 that “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....” It is also unclear how the day on which verification data are collected can differ at all from the verification date, much less by two years.

Response: The GVSDT does not see a conflict because R1.2, R2.2 and R3.2 state that you have 90 calendar days from the date the data is</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		selected for submission of the data to the Transmission Planner. The two year limit in Attachment 1 refers to how far back in time you can go when you select operational data. 2)The phrasing regarding applicability should be made more consistent. The criterion, “Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System,” in para. 4.2.3 appears to state that a station with two 500 MW fossil units (meeting NERC registry criteria) and a standby, 10 MW diesel genset connecting to the 13.2 kV bus (not meeting the NERC registry criteria), for example, needs testing only for the large units because the diesel is not part of the NERC-defined Facility. Para. 1 at the bottom of p.15 appears to take a contradictory position, however, by saying that “For generating 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.” This would be better stated as, that “For generating units of 20 MVA or less that are included as part of a Facility greater than 75 MVA in aggregate, record data either on an individual unit basis or as a group.” **Response: Your example of a 10 MW diesel genset connected to a 13.2 kV bus would not be applicable because it is not directly connected to the BES nor is it a registered unit. There is no conflict between the Applicability Section and what is on page 15 since page 15 is only Verification specifications for what is found in the Applicability Section.** 3) Applying on p.16 an “unduly restricted” classification to reactive power verification results that fall short of 50% of the thermal capability curve (D-curve) constitutes a technical error. The D-curve deals only with a single characteristic (temperature) of a single component (generator), and the reactive capability of a generation unit system is generally set by other factors. Lagging PF is frequently restricted to less than 50% of the D-curve value due to variation of aux bus voltages beyond the IEEE-recommended

Organization	Yes or No	Question 1 Comment
		range of +/- 5% for normal operation, and it is not uncommon for stability issues to preclude any leading-PF operation (nuclear units in particular never operate at leading PF). Potential lack of leading capability is acknowledged in Note 4 of Att. 1, but contradicted by the p.16 references discussed above. All explicit and implied connections in the draft standard between the expectable reactive power capability and the generator OEM D-curve should be expunged. **Response: The generator D-Curve is recognized as the absolute maximum achievable reactive capability. The reference to 50% of the D-curve is an acceptability criterion for using operational data in lieu of a staged test.** 4) Note 1 of Att. 1 (pp. 17-18) is inaccurate and should be deleted. The limitations described in our comments above are not related to transmission system conditions. Our concerns are amplified by the statement, "Observe auxiliary bus voltage limits," in Note 1 from the previously-voted-on version of MOD-025-2 having been deleted from the present draft. Is it the SDT's intent that units should import and export reactive power to the generator OEM D-curve regardless of whether or not there is risk of tripping due to aux bus drop-out? Doing so would constitute an unacceptable operational practice. **Response: The GVSDT disagrees and believes you may have misinterpreted the standard relative to reactive capability testing and the primary reason for not reaching the D-curve is likely due to system conditions. The GVSDT has repeatedly commented clearly stated in the standard that safe unit limits should not be challenged to perform this testing. Safe limits should be determined by the GO and testing should be stopped short of those limits and the reasons for stopping the test reported.**

Organization	Yes or No	Question 1 Comment
		5)Note 2 should be deleted as well ("While not required by the standard, it is desirable to perform engineering analyses to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification....") since there is no quantitative indication of what these other conditions should be or what such an analysis would mean. The line, "The recorded Mvar values were adjusted to rated generator voltage, where applicable," on P.21 should also be deleted. **Response: The GVSDT agreed after the previous posting in the Consideration of comments to remove this point ("The recorded MVAR values were adjusted to rated generator voltage, where applicable.") from Attachment 2. We apologize that it did not get removed from the standard and have removed it.** 6) Clarification is needed regarding the requirement in para. 2.1 of Att. 1 to verify capability, "at the applicable Facilities' normal (not emergency) expected maximum Real Power output at the time of the verifications." It is understood that a unit typically running for example at 720 MW in the summer and 740 in the winter could be reported at either value, depending on when the verification was performed; but the term "normal maximum" is inherently incorrect, given the dictionary definitions of "normal" as meaning standard, usual, typical etc and "maximum" as representing an extreme condition. Para. 2.1 should be changed to read, "within the Facilities' normal (not emergency) range of full load Real Power output at the time of the verifications," to indicate that readings within the dotted lines in the graph below are what's wanted, not the heavy, solid line. Note that normal power is never a single value, it is a range. It would be helpful to include a diagram on the subject, along with any statistical criteria involved in defining NERC's concept of the normal range.

Organization	Yes or No	Question 1 Comment
		Response: The GVSDT has made changes for clarity of this language several times. We believe that there is now consensus for this language and have no plans for further changes. 7) The statement on p.15 that, "It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing...," should be expunged. A considerable operational period must be reviewed to determine what the normal full-load real power range is, as explained in comment #4 above, and it is impossible to go back in time and insert a VAR test. **Response: The suggestion to perform the testing at the same time was meant for staged testing only if desired by the GO. It is not a requirement for either operational data or staged testing.** 8) The reference to "maximum Real Power" in para. 2.2.2 of Att. 1 should be changed to match the terminology in para. 2.1, after modification per our comments above. **Response: Attachment 1, 2.1 describes the maximum Real Power output for both Real Power and Reactive Power capability testing. Attachment 1, 2.2.2 only provides the time needed before recording the data for the leading reactive power test at maximum real power. The GVSDT does not feel Attachment 1, 2.1 needs to be restated in Attachment 1, 2.2.2.** 9) The requirement in para. 3.4 of Att. 1 that one record, "The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires to perform corrections to Real Power for different ambient conditions," is incomprehensible. It appears to indicate that in some cases ('if applicable") the GO may require that ambient corrections be performed, and in other cases they won't; but there is no indication when and if such calculations are mandatory, and there is no hint as to the reference conditions that GOs are supposed to correct-to.

Organization	Yes or No	Question 1 Comment
		Response: The hint is found in Attachment 1, 4.2 which states: "If an adjustment is requested by the TP, then develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later." 10) Para. 4 of Att.1 should state that the simplified key one-line diagram need be no more detailed than that shown in Att. 2. Development of diagrams showing all aux transformers and real and reactive power flows would be unduly burdensome, and the wording of Att. 2 indicates that such a level of detail is not intended. **Response: The format used should provide information comparable to that provided in Attachment 2 as stated in Requirements R1, R2 and R3. The GVSDT feels the directions are clear as currently drafted.**
Response: The GVSDT thanks you for your comments. Please see responses above.		
Ameren	No	While it is a step in the right direction to direct the Transmission Operator to take measures to maintain the system bus voltage of the plant under test at an acceptable level during the reactive power capability testing of the plant, this still does not mean that the plant would necessarily be able to reach its full reactive power output capability during the test. If it is the intent of this standard to produce reactive power limit data which would be of use for inclusion in powerflow model data, then we believe that there needs to be some means of permitting the generator owner to take the as-tested values and extrapolate to system conditions where full reactive power capability of the generator would be called upon should be allowed.

Organization	Yes or No	Question 1 Comment
Response: The GVSDT thanks you for your comments. Please reference Attachment 2, Note 1 for the permission you are requesting with regard to extrapolation.		
ExxonMobil Research and Engineering	No	No comments on this question.
Southern Company	No	
Idaho Power Company	Yes	Idaho Power System Planning as a Transmission Owner that owns synchronous condensers agrees with the revisions made to Attachment 1.
Response: The GVSDT thanks you for your comments.		
Ingleside Cogeneration LP (Voting entity Occidental Chemical Corporation)	Yes	In our view, Ingleside Cogeneration LP believes the technical language used in the latest version of MOD-025-2 Attachment 1 has been refined to an acceptable point.
Response: The GVSDT thanks you for your comments.		
SERC Planning Standards Subcommittee	Yes	Paragraph 4.2 contains several typos and the intent is not clear. Recommend revise 4.2 to read: "An adjustment may be requested by the TP to develop the relationships between test conditions and generator output at different conditions, such as peak summer conditions. If so requested, test results should be adjusted to ambient conditions specified by the TP. Adjusted results should be submitted to the TP within 90 days of the request or the date the data was recorded/selected whichever is later."
South Carolina Electric and Gas	Yes	Paragraph 4.2 contains several typos and the intent is not clear. Recommend revising 4.2 to read: "An adjustment may be requested by the TP to develop the relationships between test conditions and generator output at different conditions, such as peak summer conditions. If so

Organization	Yes or No	Question 1 Comment
		requested, test results should be adjusted to ambient conditions specified by the TP. Adjusted results should be submitted to the TP within 90 days of the request or the date the data was recorded/selected whichever is later.”
Response: The GVSDT thanks you for your comments. Based on your and other’s comments, the GVSDT revised this paragraph to: **“If an adjustment is requested by the Transmission Planner, then develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator can be determined at different conditions, such as peak summer conditions. Adjust MW values tested to the ambient conditions specified by the Transmission Planner upon request and submit them to the Transmission Planner within 90 days of the request or the date the data was recorded/selected whichever is later.”**		
Domion	Yes	
Southwest Power Pool Reliability Standards Development Team	Yes	
Bonneville Power Administration	Yes	
FirstEnergy	Yes	
Luminant	Yes	
Wolverine Power Supply Cooperative, Inc.	Yes	
TransAlta Centralia Generation LLC	Yes	
PSEG	Yes	
Xcel Energy	Yes	

Organization	Yes or No	Question 1 Comment
American Transmission Company	Yes	
American Electric Power	Yes	
Independent Electricity System Operator	Yes	
Northeast Utilities	Yes	
Chelan PUD	Yes	
Georgia Transmission Corporation	Yes	

2. **The GVSDT has revised the VSLs based on stakeholder comments. Do you agree with these revisions? If not, please explain in the comment area below.**

Summary Consideration: The industry is generally supportive of the VSLs. As a result of stakeholder comments, edits were made to VSLs for Requirements R2 and R3 to provide wording consistent with the VSL for Requirement R1– this is non-substantive because the level was not changed.

Organization	Yes or No	Question 2 Comment
Exelon Corporation and its affiliates	No	Although Exelon agrees with a majority of the revisions, it does not seem reasonable to assign a Severe VSL for a potential administrative oversight for not submitting the data to the Transmission Planner within a set period of calendar days equally to a complete failure to perform the required testing for an applicable generating unit. Exelon suggests that the administrative requirement for submitting data within a set period be limited to maximum of a High VSL and the application of the specific submission time periods be adjusted for the Low and Medium VSLs and the Severe VSL be revised to reflect inability to produce sufficient data to substantiate that the required testing was performed (i.e., the Generator Owner may have performed the test but is unable to produce any data to support the testing). As an example, the proposed example revision to the Severe VSL is as follows: The Generator Owner failed to produce data upon request of the Transmission Planner. OR The Generator Owner failed to verify the [applicable test] per Attachment 1 of an applicable generating unit.
Response: The GVSDT thanks you for your comments. The NERC VSL Development Guidelines call for providing multiple VSLs when there are varying elements in the requirement such as completeness of data and timely submission of data as well as failure to perform a verification. The GVSDT followed these guidelines in developing the VSLs for MOD-025-2.		

Organization	Yes or No	Question 2 Comment
Luminant	No	Luminant disagrees with the expanded VSLs and recommends that the SDT return to the VSL list in the previous posting. Luminant believes that the original VSL list is comprehensive and does not require expanding to include completeness of the data reported, or specific compliance to items, 1, 2, and 3 of the "Periodicity for conducting a new verification."
Response: The GVSDT thanks you for your comments. The VSLs were not revised appreciably from the previous posting. The NERC VSL Development Guidelines call for providing multiple VSLs when there are varying elements in the requirement such as completeness of data and timely submission of data as well as failure to perform a verification. The GVSDT followed these guidelines in developing the VSLs for MOD-025-2.		
Seattle City Light	No	The VSL associated with Attachment 1 Section 2.1 will often be violated, because due to constraints of load, water flow, or other operational characteristics such as generators' thermal limits it is typically not possible to run each unit at maximum real power and lagging reactive power for a minimum of one hour as required.
Response: The GVSDT thanks you for your comments. The GVSDT assumes that you are referring to variable generation in your comment. Attachment 1, Section 2.1.2 states: "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." If this is met, then there is no violation of the requirement and the VSLs are moot.		
Ameren	No	There seems to some discrepancy in the reporting date that the VSLs are based on when using the operational data to verify. The first section in the VSL for R1 is worded slightly differently than the same portion of the VSL for R2 and R3. For R1, the reporting date seems to be based on the date that the data is selected for verification based on historical data, whereas for R2 and R3 the reporting date seems to be based on the date when the historical operating point was reached. Please clarify the SDT's intention to have such a difference, as it could make a big difference in meeting the reporting date deadline, and cause confusion among Generator Owners.

Organization	Yes or No	Question 2 Comment
Response: The GVSDT thanks you for your comments. The GVSDT intended the language to be the same for each requirement. The VSLs for R2 and R3 were revised to match the language in R1.		
ExxonMobil Research and Engineering	No	No comments on this question.
Idaho Power Company	Yes	Idaho Power System Planning agrees with the revised VSLs.
Manitoba Hydro	Yes	None.
Southwest Power Pool Reliability Standards Development Team	Yes	
Bonneville Power Administration	Yes	
FirstEnergy	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Duke Energy	Yes	
Associated Electric Cooperative, Inc. - JRO00088	Yes	
SERC Planning Standards Subcommittee	Yes	
Southern Company	Yes	

Organization	Yes or No	Question 2 Comment
pacificorp	Yes	
Wolverine Power Supply Cooperative, Inc.	Yes	
Wisconsin Electric Power Company	Yes	
Dynegy	Yes	
South Carolina Electric and Gas	Yes	
TransAlta Centralia Generation LLC	Yes	
PSEG	Yes	
Xcel Energy	Yes	
Ingleside Cogeneration LP (Voting entity Occidental Chemical Corporation)	Yes	
American Transmission Company	Yes	
Independent Electricity System Operator	Yes	
Northeast Utilities	Yes	

Organization	Yes or No	Question 2 Comment
Chelan PUD	Yes	
Georgia Transmission Corporation	Yes	

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

Summary Consideration: The following note was added to the Effective Date section for clarity – "The verification percentage above is based on the number of applicable units owned."

As a result of stakeholder comment, clarification was added to the Effective Date section regarding regulatory approval in Canada.

In response to stakeholder comments, the following non-substantive changes were made in Attachment 2:

1) A clarifying phrase was added to the header in the "last verification" column

2) A bullet point in the Summary of Verification that was intended to be removed during the last comment cycle and was not, has now been removed

3) The tap setting and voltage ratio wording were made consistent throughout Attachments 1 and 2.

Organization	Question 3 Comment
ACES Power Marketing Standards Collaborators	(1) What measure does the effective date use when determining percentage of applicable Facilities that must be completed by the given date? Is it a percentage based on the net nameplate rating of the generator? We suggest this should be stated directly to avoid conflicts between what the auditor assumes versus what the registered entity assumes. **Response: The SDT has added a clarifying note as follows: "Note: The verification percentage above is based on the number of applicable units owned."** (2) Attachment 2 discusses subtracting tertiary real and reactive power to get net real and reactive power, yet there is no entry for it. Should there be an entry added in the form? **Response: Tertiary loads are accounted for on the one-line diagram and associated table as point C.** (3) The response to our last comments regarding inclusion of the last verification column indicated that a note would be added to indicate that this column would be blank for the initial verification. We could not find the note. Please add it. We were concerned a similar issue to the one

Organization	Question 3 Comment
	experienced with the Protection System Maintenance and Testing standard would be experienced. In the PRC standard, auditors interpreted statements in the standard to require data prior to the enforceable date even though registered entities were not required to keep it. It resulted in a number of violations. **Response: The GVSDT has added this note as follows: "Previous Data; will be blank for the initial verification"** (4) In applicability sections 4.2.1 through 4.2.3, please change "directly connected to the BES" to "that are part of the BES". Per the BES definition, generation units can be and are part of the BES. Using "directly connected to the BES" could draw in a non-BES unit. **Response: The GVSDT has used the registry criteria to identify applicable Facilities. The MVA limits shown will prevent non-BES units from being included under the standard.** (5) How will mothballed units be handled? If a mothballed unit is returned to service, is it treated like a new unit with the return date serving as the commissioning date? **Response: The GVSDT has added the following clarification to Attachment 1, Item 3 under Periodicity for conducting a new verification, "Existing units that have been in long term shut down and have not been tested for more than five years shall be verified within 12 calendar months. "**
Response: The GVSDT thanks you for your comments. Please see responses above.	
Ameren	(1)We believe that for sets of generators that are designed and operated identically, there should be a provision allowing use of "Sister Units" for compliance as done in MOD-026. **Response: 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.** (2)We believe the 5 year cycle with a 66 month limit is too stringent. We request that due to possible outage scheduling issues or other impacts, extending this 66 month limit by 18 months allowing a maximum of 84 months between test verifications.

Organization	Question 3 Comment
	Response: The GVSDT believes that industry consensus has been achieved in this regard. Outages are not required for this testing. (3)Was it the intent of the SDT to leave out a minimum verification time of one hour for both MW and MVAR verification? Could the SDT please clarify their intention and if a minimum of one hour was intended? **Response: Attachment 1, Item 2.1.1 states: “Verify synchronous generating unit’s maximum real power and lagging reactive power for a minimum of one hour.”**
Response: The GVSDT thanks you for your comments. Please see responses above.	
Duke Energy	1) Attachment 2, Summary of Verification - Strike the fifth bullet (The recorded Mvar values were adjusted to rated generator voltage, where applicable.) In the Consideration of Comments Report the Standard Drafting Team agreed to make this change, but it was overlooked. **Response: The GVSDT has made this correction.** 2) The focus of this standard appears to be on testing rather than on verifying the P and Q limits to be used in Transmission Planning models. The standard is more of a performance test than a model verification test - the requirements do not directly fulfill the purpose. **Response: The verifications performed under this standard are intended to provide actual performance data as inputs to the models and the GVSDT believes that industry consensus has been achieved in this regard.** 3) Leading VAR Staged Testing - Leading VAR staged testing provides little benefit to the BES and should only be performed once in an initial staged test or validation. The fact that the regions will not be able to provide operational data for the leading VAR test points requested, proves that the system usually doesn’t require leading VARS. In the situations such as system recovery and lightly loaded BES where leading VARS may be required, the initial testing and validation that the unit’s heat removal capability (such as lagging VAR operational data) is sufficient, should serve as satisfactory verification of the unit’s capability. The risk (and cost) of repeated operation of the unit in the maximum leading VAR is not warranted for the little benefit it provides to the BES. The risk of

Organization	Question 3 Comment
	Step Iron degradation and loss of synchronous operation every five years far outweighs the benefit such testing would provide the BES once the unit has been proven capable. The lagging VAR capability test or validation will prove that the unit's heat removal capability has not been compromised. MOD-025-2 should be reworded to only require periodic validation (either by staged testing or operational data) for lagging VARS, and that periodic leading VAR testing only be required if the unit is not capable of passing the lagging VAR capability test or validation. **Response: The SDT is responding to FERC directives as part of the revisions of this standard. In one of the FERC directives (Order 693, Paragraph 1321) testing at multiple points was required. The standard does not require any testing that would violate any equipment operating limits or lead to equipment damage.** 4) Applicable Facilities - Verification of units between 20 MVA and 100 MVA provide little benefit to the BES for the risk and cost of performing the staged test for these units. The maximum VAR contribution for these units is in the 5 to 20 MVAR range, and the risk and cost for testing, documentation and auditing of units of this size is not warranted for the small benefit gained. If there is a specific need for a particular small unit to provide VAR support due to regional constraints, then it should be validated. But to require validation for all the small units that have little impact on the reliability of the BES, the cost is not warranted. The unit size applicability for PRC-019-1 and MOD-025-2 should be set equivalent to that specified by MOD-026 and MOD-027 (i.e. in the Eastern Interconnection, individual generating units greater than 100 MVA directly connected to the BES, etc.). Regional criteria can be used to address any smaller units identified as critical to BES reliability in that region. **Response: The GVSDT has used the registry criteria to identify applicable Facilities and believes that industry consensus has been achieved in this regard.**
Response: The GVSDT thanks you for your comments. Please see responses above.	
Texas Reliability Entity	1) Seasonal considerations for Real and Reactive Power do not appear to be considered in this Standard. This could be detrimental to use in Planning and Operations models for specific periods. **Response: Seasonal conditions were considered for Real Power. The GVSDT has revised this**

Organization	Question 3 Comment
	sentence for clarity as: "If an adjustment is requested by the TP, then develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator can be determined at different conditions, such as peak summer conditions. 2) In section 4, the phrase "directly connected to the Bulk Electric System" may have the unintended consequences of excluding a generator unit connected to the BES through a 69/138 kV autotransformer (for example). Suggest removing 'directly' from these requirements. **Response: The GVSDT has used the registry criteria to identify applicable Facilities and believes that industry consensus has been achieved in this regard.** 3) Considering the proposed new BES definition and the Guidance Document, there may be confusion in determining if a generator is "directly connected" to the BES. Please consider reviewing the language to see if it should instead say "included in" the BES. Note that a BES generator can be connected to the BES by non-BES elements, and arguably not "directly connected" to the BES. See, for example, figures E1-4 and E1-6 in the BES Definition Guidance Document. **Response: The GVSDT has used the registry criteria to identify applicable Facilities and believes that industry consensus has been achieved in this regard.** 4) TRE recommends changing to "Planning Authority or Transmission Planner" in the requirement sections instead of "Transmission Planner". The change may be needed since the Planning Authority or the Transmission Planner may have the responsibility for modeling the generation data provided by the Generator Owners. **Response: The GVSDT has set the requirements for model verifications to be submitted to the Transmission Planner. Per the NERC Reliability Functional Model, the Transmission Planner provides this information to the Planning Coordinator. The GVSDT believes that stakeholder consensus has been achieved in this regard.** 5) The Functional Entities are listed as the Generator Owner and the Transmission Operator. However, the VAR standards have the Transmission Operator provide the Generator Operator a voltage or reactive schedule and require the Generator Operator to maintain that voltage or reactive schedule. Should the Generator Operator be included in this standard for verification and

Organization	Question 3 Comment
	data reporting? There are many cases where the Generator Owner is not the Generator Operator and confusion could result (or incorrect data/testing) if different criteria were provided. **Response: Per the NERC Reliability Functional Model, the Generator Owner is the responsible entity for "Establish generating facilities ratings, limits, and operating requirements." (see page 50, item 1 of the Functional Model).** 6) Overall the timing is too long. Waiting 12 calendar months for verification impacts reliability. Based on this requirement, the capability could be reduced by 50% but not tested for 12 calendar months (or longer). That could put significant strain on a local system that may not be tested for an extended period and yet be compliant with the standard. **Response: The standard is intended to verify long term planning models. The GVSDT believes that industry consensus has been achieved in regards to the 12 month verification specification.**
Response: The GVSDT thanks you for your comments. Please see responses above.	
Wisconsin Electric Power Company	1. In Attachment 1 Section 2.2.1, we take issue with the requirement to verify reactive power capability at the minimum real power output. We are not convinced this is necessary for BES reliability. The reactive capability at this point can be estimated by the GO with sufficient accuracy for the planning model. Verification of reactive output at minimum real power requires considerable effort and resource scheduling flexibility for data which can be readily estimated without adverse impact to the BES. Especially for large units, it may require a multiple day effort to verify reactive power at the minimum and maximum real power points, due to issues with auxiliary equipment. **Response: The standard only requires testing up to the point any limit is reached and as such extended testing times should not be required. FERC Order 693 (Paragraph 1321) requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve.** 2. Attachment 2: On the One Line Diagram and the following data table, it is indicated that the net unit capability is to be provided at the GSU high-side (Point F). This should be revised to allow the GO to provide the net capability at the GSU low-voltage side instead. There may not be adequate

Organization	Question 3 Comment
	metering capability at the GSU high-side, whereas metering at the generator voltage level is commonly available. **Response: The standard allows calculation of the net capability if appropriate metering is not available. See Section 4.1 of attachment 1.**
Response: The GVSDT thanks you for your comments. Please see responses above.	
Chelan PUD	1. It is unclear how auxiliary load should be calculated where several units share a common station service power supply and all units are not in operation (multi unit hydro plant). Suggest some guidelines in allocation in these cases should be included. **Response: The auxiliary load should be allocated amongst the running units. The standard allows for engineering analysis and that could be utilized to calculate the appropriate auxiliary load.** 2. It may not be possible to generate maximum real power for one hour for hydro with small reservoir volumes. Similar to run of river hydro, reservoir volume or other license requirements may restrict this ability. Suggest a similar allowance in these cases to the run of river power qualification. **Response: Section 2.1.2 of Attachment 1 addresses verification of variable resources and only requires that verification be conducted at the maximum level that can be achieved at the time of the verification. Wind, solar, and run of river hydro were mentioned only as examples of variable resources.** 3. R2 requires the Generator Owner to verify Reactive Power capability per Attachment 1, and submit the data per Attachment 2. Note 1 and Note 2 on Attachment 1 are commentary on the meaning of the test results and imply additional analyses is expected but provide no explicit directions that must be taken. Note 1 recognizes that the value of the testing may be limited to uncovering MVAR limitations. Note 2 is a commentary that encourages the Generator owner to perform engineering analyses, but the expectations are unclear. MOD-025-2 must clearly describe what engineering analyses are to be performed, what operational data is required to support the analyses, and the deliverables of this effort. MOD-025-2 should be made more specific regarding acceptable system conditions for collecting test or operational data, and the extent to which

Organization	Question 3 Comment
	engineering analysis is required for model verification. **Response: The standard does not require engineering analysis and its use is completely at the option of the Generator Owner.** 4. It may not be possible to test full reactive capability at minimum power for hydro units due to the broad capability curve without exceeding TOP established voltage schedules. I suggest going to some percentage of the "full" value to verify the curve with concurrence of the TOP and TP in these cases or test documentation of limiter settings. If the GO is required to perform staged test, the TOP and RC must be able to support it. Some system should be established where this cannot be done. **Response: The standard only requires testing to the point a limit is reached. There is no requirement to reach any “full value”.**
Response: The GVSDT thanks you for your comments. Please see responses above.	
Tennessee Valley Authority	1. Entire Attachment 2, recommend linking Att 2 data entries to Att 1 requirements by adding (e.g. Att 1 requirement _____) in parenthesis, to each Att 2 line/bullet. Justification is to define the source requirement for the data. **Response: The standard does not require use of Attachment 2 as is. The Generator Owner can modify Attachment 2 or create an alternate form that provides the required data. Cross references to Attachment 1 could be included in the revised form if the Generator Owner wishes** 2. Attachment 2, Summary of Verification, recommend adding the following bullet under “Transformer Voltage Ratio: ...”Add: “Transformer Tap Setting: GSU ___, Unit Aux ___, Station Aux ___, Other Aux ___”Justification is to be consistent between Attachment 1 and Attachment 2. Current Attachment 1, 3.6, identifies “transformer(s) tap setting”; Attachment 2, had data entries for “Voltage Ratio.” Both values are legitimate transformer parameters. **Response: The SDT agrees with your suggestion and has made the suggested change to Attachment 2.** 3. Overall Standard, The focus of this standard appears to be on testing rather than on verifying the

Organization	Question 3 Comment
	limits to be used in Transmission Planning models. The standard is more of a performance test than a model verification test. Justification is that the requirements do not directly fulfill the purpose. **Response: The GVSDT believes that the requirements do fulfill the purpose and that industry consensus has been achieved in this regard.** 4. Overall Standard, recommend removing the requirements to perform "staged testing." Justification is that staged testing should only be required if requested by the TOP. Justification is that verification of the true reactive limits via staged testing often produces less than optimal results because of transmission system constraints. **Response: Reasons for staged or operational testing requirements have been well documented in previous consideration of comments documents.** 5. Standard, 4.0 Applicability, The unit size applicability for MOD-025-2 should be set equivalent to the unit size applicability found in MOD-026 and MOD-027 (i.e. MOD-026-1 Draft, 4.2, Facilities, 4.2.1, Generation in the Eastern or Quebec Interconnections ...(including 4.2.1.1, 4.2.1.2); 4.2.2 Generation in the Western Interconnection ...(including 4.2.2.1, 4.2.2.2); 4.2.3 Generation in the ERCOT Interconnection ...(including 4.2.3.1, 4.2.3.2). Justification is to be consistent across all generator verification standards (e.g. Generation in the Eastern Interconnection with individual units greater than 100 MVA, etc.) **Response: The GVSDT has used the registry criteria to identify applicable Facilities and believes that industry consensus has been achieved in this regard.**
Response: The GVSDT thanks you for your comments. Please see responses above.	
Manitoba Hydro	1. Manitoba Hydro has a concern with respect to the phased in implementation measured by percent compliance. We believe that this may lead to a potential for some uncertainty and debate. Does a phased in implementation such as this, do anything to increase reliability? **Response: The reason for a phased implementation is to allow Generator Owners a reasonable schedule for testing.** 2. Attachment 1 of MOD-026-1 (Note 2) and M0D-027-1 (Note 3) contain a section titled

Organization	Question 3 Comment
	"Consideration for early Compliance" with language pertaining to previous testing and model verification which were completed under the applicable regional policies, guidelines or criteria or which are compliant with the requirements of the standard. Manitoba Hydro recommends that similar language be included in the other standards (PRC-019-1, MOD-025-2 and PRC-024-1). **Response: The phased implementation was developed to allow GO's sufficient time to perform the verification on their units. Because of this, the GVSDT does not believe an early compliance provision is needed.**
Response: The GVSDT thanks you for your comments. Please see responses above.	
Alberta Electric System Operator (AESO)	1. In section 4.2 The AESO considers the existing applicability for reactive power verification to be more appropriate: o Connected to a transmission grid at 60 kV or higher voltage; and o single unit capacity of 10 MVA and larger; or o facilities with aggregate capacity of 20 MVA and larger. **Response: The GVSDT has used the registry criteria to identify applicable Facilities and believes that industry consensus has been achieved in this regard.** 2. Attachment 1, the statements regarding testing the capability of units with a change lasting more than 6 months within 12 months of the change appears to be in conflict with each other. EG: If a change is in place for 7 months but not tested in these 7 months and then issue is rectified how is this change then tested? The time frame for testing cannot exceed the time that change is in effect. **Response: The standard allows up to 12 months to complete a test upon discovering the change. If the issue is rectified before the end of the 12-month period a test is not required.**
Response: The GVSDT thanks you for your comments. Please see responses above.	
Independent Electricity System Operator	1. The effective dates in the proposed Implementation Plan and in Section A5.1 of the standard may conflict with Ontario regulatory practice respecting the effective date of implementing approved standards. It is suggested that this conflict be removed by: a. In the Implementation Plan, under the Section "In those jurisdictions where regulatory approval is required:", adding a phrase ", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities,"

Organization	Question 3 Comment
	right after "following applicable regulatory approval" and before "each Generator Owner..."b. In Section A5.1 of the standard, adding the same phrase ", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities," right after "following applicable regulatory approval," and before "each Generator Owner...". **Response: The GVSDT has made the suggested clarifying revision.** 2. There are four measurements of "Gross Reactive Power Capability" for generators: over-excited and under-excited at minimum and maximum active power outputs. Which one of the four measurements should be recorded in Appendix 2 under "Gross Reactive Power Capability"? **Response: By utilizing the check boxes in Attachment 2, the particular test or tests that are being recorded are specified.**
Response: The GVSDT thanks you for your comments. Please see responses above.	
ExxonMobil Research and Engineering	A stated purpose of Generator Verification is "to ensure that generator models accurately reflect the generator's capabilities and operating characteristics." Modeling behind-the-meter generation based on gross name-plate ratings will not accurately reflect those assets' capabilities or operating characteristics, and, in fact, may seriously distort BES expansion plans or other modeling scenarios if name-plate ratings are used. Behind-the-meter generation is a misnomer. It is not comparable to utility or merchant generation in which the primary function is to deliver electric energy to the bulk electric system. The primary function of behind-the-meter generation that employs cogeneration or combined heat and power (CHP) systems is to deliver thermal energy (usually in the form of steam) in support of the load's process technology. In the case of industrial loads, the capabilities or operating characteristics of that process are a function of the load's production schedule associated with its products (e.g., chemicals, petroleum, paper, etc.) and independent of conditions on the BES. Any electric power delivered to the BES is a residual by-product of the industrial process and generally a small fraction of the name-plate rating of the generator. Section III.c.4 of the Statement of Compliance Registry Criteria (v.5) and Exclusion E2 of the revised BES definition both recognize this fundamental characteristic of behind-the-meter generation and that is why neither document uses name-plate rating as a useful metric for behind-the-meter generation. The GVSDT is urged to do the same. Additionally, the SDT should define the term 'Synchronous condenser' so that it is

Organization	Question 3 Comment
	clear that a large synchronous motor is not a synchronous condenser.
Response: The GVSDT thanks you for your comments. The GVSDT has used the registry criteria to identify applicable Facilities . If a unit meets the registry criteria it is obligated to comply with the standard. **The GVSDT feels that the accepted industry understanding would not allow a synchronous motor to be confused with a synchronous condenser.**	
Florida Municipal Power Agency	A synchronous condenser can be owned by either a TO or GO. For instance, there are installation of generators where a clutch is installed to separate the electric generator from the prime mover to run the electric generator as a synchronous condenser. Such a synchronous condenser would be owned by a GO. The standard should not force a GO to register as a TO simply because it owns a synchronous condenser. FMPA recommends making the requirement applicable to a GO or TO whoever owns the synchronous condenser.
Response: The GVSDT thanks you for your comments. There are separate requirements for a GO and a TO. Requirement R2 applies to a GO who owns a synchronous condenser and Requirement R3 applies to a TO that owns a synchronous condenser. A GO will not need to register as a TO if they own a synchronous condenser.	
Lincoln Electric System	Although supportive of the standard drafting team's efforts, LES believes MOD-025 could be further enhanced in consideration of the following recommendations. Recommend Attachment 1 "Periodicity for conducting a new verification" be revised to require verification of the Real Power capability on an annual basis with Reactive Power remaining at every 5 years. In consideration that regions such as the MRO and SPP maintain existing procedures requiring members to perform Real Power verification at a minimum of annually, LES believes this reduced timeframe is not only reasonable but also achievable for entities. Additionally, it seems reasonable to expect a re-verification be performed if the Real Power is reduced by as little as 5 percent as several units with that level of lost capacity could be significant in adversely affecting the integrity of the BES. **Response: The SDT believes that industry consensus has been achieved regarding the required**

Organization	Question 3 Comment
	periodicity of testing. Recommend Attachment 1 “Verification specifications for applicable Facilities” Part 3.4 be modified to specify the duration of the verification period and that the data supplied should be an average of the verification test period. - Per the standard, the purpose of MOD-025 is to ensure accurate information is available for the planning models in order to assess BES reliability. NERC annually builds 4 seasonal peak models (summer, winter, spring and fall) in addition to a spring minimum model. Within these models the TPs must provide Real Power maximum and minimum values and up to 10 sets of correlated real and reactive values in order to model a generators “D curve”. As such, LES would recommend that the GO develop these values and provide them to the TO. While Real Power Max is tested it is only done under the conditions of a single season, it would then be up to the TP to adjust the MW output for the other 3 seasons. LES believes the GO is the more appropriate person to make these adjustments rather than the TP. Additionally, Real Power minimum testing is not addressed within this standard. LES believes with the increase in highly variable generation, such as wind, generators may end up operating at their minimums much more than they have done historically and therefore Real Power minimums should be verified on an annual or 5 year basis as well. In terms of Reactive Power generation, a GO should be required to go beyond what is required in the current Attachment 2 and align with the number of correlated Real/Reactive sets which the TP is required to provide in their models to NERC. - In further support of BES reliability, LES recommends that the net Real Power output for generating facilities be adjusted based on a high temperature for the month based on the model that the Real Power output is being developed for, i.e. summer, winter, spring, fall, or minimum model. The criteria for determining what should be used for a high temperature adjustment point could be an average of the entity’s high temperature for the month over a ten-year period or possibly the 0.4% ASHRAE temperature could be used. LES believes it would not be unreasonable to expect that data be supplied by the GO for the seasons required for model submission by the TP. **Response: If the Transmission Planner requires ambient adjustments to the tested values the standard requires that adjusted values be provided (Section 5 of Attachment 1). The standard requires real power testing at minimum load.**

Organization	Question 3 Comment
Response: The GVSDT thanks you for your comments. Please see responses above.	
American Transmission Company	ATC recommends the following changes: Attachment 1, Periodicity for new verification Item 3 - Allow for mutually agreed on flexibility by adding the wording at the end of the sentence like, ". . . or a mutually agreed verification date." **Response: The GVSDT believes that testing of new facilities should be conducted within one year and that stakeholder consensus has been achieved regarding this language.** Attachment 1, Verification Specifications Item 2.1.2 - The wording is unclear near the end of Item 2.1.2. ATC recommends this be changed to read, "Reschedule the test of the facility within six months after being unable to test at or above the 90 percent threshold". **Response: The GVSDT disagrees. The six month interval is the period allowed to complete the testing following the date that the facility has 90 percent or more of its units available to test.**
Response: The GVSDT thanks you for your comments. Please see responses above.	
Domion	Dominion suggests that footnote 1 not contain the capitalized term Wind Farm Verification as this is not defined in either this standard or the NERC Glossary of Terms.
Response: The GVSDT thanks you for your comments. The GVSDT agrees and has revised this to "Wind farm verification…"	
Idaho Power Company	Idaho Power System Planning as a Transmission Owner that owns synchronous condensers has the following comments for the GVSDT to consider: Attachment 1 - Item 2.1.1 lists the verification duration for a synchronous generating unit at maximum real power and maximum reactive power with a one hour testing duration. Idaho Power System Planning comments that the voltage schedule may be difficult to maintain during a one hour test at maximum reactive power for a one hour test during for N-0 system conditions. Idaho Power System Planning asks the GVSDT to consider a 30 minute testing duration for performing the verification to be consistent with the 30 minute duration established for operators to make manual

Organization	Question 3 Comment
	system adjustments following contingency events. **Response: The time period selected was based on allowing for time for the unit to achieve a stable operating condition. The standard does not require exceeding any limits including voltage schedules during the test.** Attachment 1 - Item 2.1.2: Idaho Power System Planning comments that it is unclear what the maximum reactive capability testing duration is for variable generating units. Idaho Power System Planning asks the GVSDT to include the minimum testing duration for variable generating units for the maximum reactive capability test. **Response: The standard does not differentiate the type of unit being tested and the SDT does not see a need to do so. For reactive testing, the standard only requires recording the value achieved at the end of the test period.** Attachment 1: Idaho Power System Planning comments that it is unclear what the maximum reactive capability testing duration is for synchronous condensers. Idaho Power System Planning asks the GVSDT to include the minimum testing duration for synchronous generators for the maximum reactive capability test. Requirements to submit verification with 90 days of test date are unreasonable. 365 days is more reasonable, and is consistent with MOD-026-1 and MOD-027-1. **Response: See response to question 2 above. The SDT believes the 90 day deadline is reasonable and industry consensus has been achieved on this issue.**
Response: The GVSDT thanks you for your comments. Please see responses above.	
Northeast Power Coordinating Council	If the primary purpose of obtaining net Real Power and net Reactive Power is to build system models to support planning studies, then the Drafting Team should consider that MOD-025 may not be required and could be eliminated. Under Standard IRO-010-1a the Reliability Coordinator can require GOs and TOs to submit Real and Reactive Power data in a format the RC deems necessary. The detailed requirements of MOD-025 can be addressed in IRO-010-1a. **Response: The verifications required under MOD-025-2 are to verify the unit capability for an applicable Facility, not real-time characteristics as required in IRO-010-1a. The drafting team is**

Organization	Question 3 Comment
	also addressing a FERC Order 693 directive to: *"direct the ERO to modify MOD-025-1 to require verification of reactive power capability at multiple points over a unit's operating range".* This was discussed during the first comment period of the standard and the majority of stakeholders agreed with our approach. Suggest the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the Standard and the associated Implementation Plans. Given recent experience with other Standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings. **Response: The SDT has added a clarifying note as follows: "Note: The verification percentage above is based on the number of applicable units owned."** If the Drafting Team believes that a separate Standard to verify the gross and net Real and Reactive Power of the turbine generator is required, then MOD-025 should be limited to requiring the reporting of maximum Real and Reactive Power only. In our view the detailed data requirements specified in Attachment 1 and 2 are not required for planning studies. The data in Attachments 1 and 2 have value to plant personal to evaluate unit efficiency and performance, but this data is not needed to support reliability. This data is more relevant to market functions. **Response: The verifications required under MOD-025-2 are to verify the unit capability for an applicable Facility. The drafting team is also addressing a FERC Order 693 directive to: *"direct the ERO to modify MOD-025-1 to require verification of reactive power capability at multiple points over a unit's operating range".* This was discussed during the first comment period of the standard and the majority of stakeholders agreed with our approach. The other data is provided to make adjustments if requested.**
Response: The GVSDT thanks you for your comments. Please see responses above.	

Organization	Question 3 Comment
South Carolina Electric and Gas	In attachment 1, change the periodicity for performing Real and Reactive Power capability verification from five years to ten years. This would be consistent with standards MOD-026 and MOD-027.
SERC Planning Standards Subcommittee	In attachment 1, change the periodicity for performing Real and Reactive Power capability verification from five years to ten years. This would be consistent with standards MOD-026 and MOD-027. 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 comments. The GVSDT believes that the verification periodicity for Real Power and Reactive Power capability is appropriate at five year intervals and was addressed in previous comment periods. The GVSDT believes that stakeholder consensus has been achieved in this regard.	
Ingleside Cogeneration LP (Voting entity Occidental Chemical Corporation)	Ingleside Cogeneration LP agrees that the ability for Transmission Planners and other operating entities to be able to rely on a generator's available real and reactive capacity under system duress is essential to BES reliability. In addition, the technical veracity and implementation time frames in the latest version of MOD-025-2 are far improved over previous versions. However, we are concerned with the aggregate work load that all five standards in Project 2007-09 will place upon our engineering and operations organizations. Each has its own unique purpose, which means unique processes to support them - as well as test results that demonstrate compliance. With so much uncertainty surrounding this program, we cannot agree to proceed without the following items being addressed: 1) All requirements for recurring tests (R1 and R2) must contain language that focuses on the strength of the validation process - not the execution. This could be similar to that used in the CIP version 5 standards calling for the Responsible Entity to implement an action "in a manner that identifies, assesses, and corrects deficiencies". Experience has shown that without this preface, auditors will focus on missed due dates, whether or not all check boxes are filled in, and statements showing that every sub-requirement was addressed - even those not applicable to the facility. The CEA's focus needs to be on the entity's commitment to the validation effort, not the documentation.

<table>
<tr><th>Organization</th><th>Question 3 Comment</th></tr>
<tr><td></td><td>2) The Compliance organization needs to be engaged in the development process so that industry stakeholders have a sense of how adherence to the standard will be determined. The existing process is disconnected - leading to inconsistent interpretations of the drafting team's original intent. Other projects have begun to post drafts of the RSAWs concurrently with the standards for exactly this reason. The SDT should take note that these modifications are consistent with the risk-based compliance direction that both NERC and FERC support. The intent is to focus industry and regulatory resources on the reliability aspects of the initiative - not its administrative aspects</td></tr>
<tr><td colspan="2">Response: The GVSDT thanks you for your comments. Your issues relate to the "Find, Fix and Track" process that was most notably incorporated in the CIP body of standards. For example, CIP-003-5, Requirement R2 states:"Each Responsible Entity for its assets identified in CIP-002-5, Requirement R1, Part R1.3, shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented cyber security policies that collectively address the following topics, and review and obtain CIP Senior Manager approval for those policies at least once every 15 calendar months:" This requirement relates to a specific program that addresses a wide range of topics, including documentation of the processes involved. The requirements of MOD-025 are to simply verify the output of an applicable Facility and report it. Under this standard, the responsible entity either performed the verification and reported it or they didn't. There is no inherent program deficiency that can be identified and corrected. The GVSDT does not believe that this approach is applicable to the requirements that we have developed.</td></tr>
<tr><td>JEA</td><td>JEA supports the comments of the NAGF and believes that the SDT team should accept a request by the NAGF to have a joint meeting to discuss and resolve the many differences since these differences are so substantial that the usual iterative process will be excessively long. We also support NAGF's suggestion to evaluate these standards using the Cost Effective Analysis Process.</td></tr>
<tr><td colspan="2">Response: The GVSDT thanks you for your comments. The GVSDT did not receive any comments from the NAGF, however others have mirrored the intent to concur with their comments (see specifically Cowlitz). We have responded to those comments above. The CEAP is not in effect as this time and cannot be implemented at this time.</td></tr>
<tr><td>Exelon Corporation and its affiliates</td><td>Section D, "Compliance," Part 1.2, "Evidence Retention," (page 6 of 22) first paragraph is unnecessary and redundant since the retention periods specified are for the time period since the last compliance audit. Exelon suggests that this paragraph be deleted in its entirety.</td></tr>
</table>

Organization	Question 3 Comment
Response: The GVSDT thanks you for your comments. The first paragraph of this section is boilerplate language provide by NERC for inclusion in all standards.	
Southern Company	The focus of this standard appears to be on testing rather than on verifying the P and Q limits to be used in Transmission Planning models. An engineering study for reactive capability is an option that needs to be allowed by this standard Currently, the standard is more of a performance test than a model verification test - the requirements do not directly fulfill the purpose. Applying an "unduly restricted" classification to reactive power verification results that fall short of 50% of the thermal capability curve (page 16) creates a technical error that does not prove or disprove the reactive capability of the generating unit. The D-curve represents the thermal characteristic of a single component (generator). The reactive capability of a generation unit system is also a function of other factors. These other factors include the transmission system bus voltage, GSU impedance and tap setting, unit auxiliary transformer and downstream station service transformer impedances and tap settings, station service bus loadings and voltage limits, and the excitation limiter settings. Staged testing has limitations when attempting to prove a unit's reactive capability. We currently use an engineering assessment approach that establishes a unit's expected reactive capabilities using an analytical model. The model has been validated using historical operational data. The model takes into account all the above factors and is used to estimate the unit's reactive capabilities for extreme system voltage conditions when unit's reactive limits will be challenged. The limits are then reviewed by plant operations to ensure any operational limitations have been identified and factored into the assessment. This has proven to be a better process for establishing the reactive limits needed for the transmission planning system models than the use of staged test data. MOD-025 should not require "staged testing" without option. Staged testing should only be required if requested under TOP-002-2b R13. This will ensure the appropriate system conditions exist to support the testing (coordinated by the TOP and RC). This eliminates the GO from being required to perform testing that cannot be supported by the TOP and RC. Industry experience has shown that verification of the true reactive limits via staged testing is typically not possible due to transmission system constraints. Due to these constraints, an option to use engineering analysis for validation should be allowed by this standard. While the standard could allow staged testing as an option, we believe that staged testing should only be considered when there is a demonstrated need for the

Organization	Question 3 Comment
	testing. The unit size applicability for PRC-019 and MOD-025 should be set equivalent to that specified by MOD-026 and MOD-027. We do not see significant value in a 5-year re-verification cycle through staged testing. We believe a periodic confirmation that the previously verified MW and MVAR capabilities are still valid does have value. Re-verification should only be necessary when there is a long term configuration change, a major equipment modification, or equipment problems that impact the unit MW or MVAR capabilities. Possible equipment problems are being used as reason by some for wanting staged testing and periodic re-verification. Equipment problems that could limit real and reactive power capability generally manifest themselves during normal operation. These are appropriately addressed via normal operational reporting to satisfy requirements in TOP-002-2.1b and VAR-002-2b and are corrected through normal maintenance practices. Therefore, we do not agree that concerns for equipment problems justify periodic testing of every generator in the BES. Furthermore, that approach will subject the BES to a constant state of testing and off-normal operational conditions that we believe could actually prove to be detrimental to BES reliability. The recorded Mvar values were adjusted to rated generator voltage, where applicable," on p.21 should be deleted because it does not make sense to do this.
Response: The GVSDT thanks you for your comments. Historical operational data may be used for subsequent verifications if the data meets the requirements in the standard. The GVSDT has developed the applicability of the standard based on the NERC registry criteria. **Again, MOD-025-2 allows the use of historical operational data for re-verifications. Equipment problems that limit a units capability will not always manifest themselves during normal operations. Reactive limitations reported under the VAR and TOP standards are Real-time or Operations Planning issues and are not reported to the Transmission Planner. These issues have been addressed during prior comment periods. The GVSDT agreed after the previous posting in the Consideration of comments to remove this point ("The recorded MVAR values were adjusted to rated generator voltage, where applicable.") from Attachment 2. We apologize that it did not get removed from the standard and have removed it.**	
NIPSCO	This is the information that generator owners are supposed to provide every year to transmission owners as part of the MOD-10 data submittal. Why a new standard is being developed instead of

Organization	Question 3 Comment
	modification of the existing MOD-10 is questionable. The burden for complying with this standard falls almost entirely with the generation group, e.g., electric production. Given the above, Transmission Planning recommends a vote in favor of this standard.
Response: The GVSDT thanks you for your comments. MOD-011 relates to steady state data requirements and requires the following data be submitted with respect to generating units: **"R1.2. Generating Units (including synchronous condensers, pumped storage, etc.): location, minimum and maximum Ratings (net Real and Reactive Power), regulated bus and voltage set point, and equipment status."** **MOD-025-2 requires that the capability of a unit be verified as, over time, equipment operating characteristics change.**	
Wolverine Power Supply Cooperative, Inc.	This standard is redundant. We are already required by MISO to provide real power data. It would be more logical for this standard to be applicable to the RTO because they are already asking for most of this data. I would rather have MISO expand what they are asking for and have them pass the data along to NERC, than to have to comply with two entities asking for the same thing with slightly different methods.
Response: The GVSDT thanks you for your comments. The standard applies continent-wide and does not require that any data be submitted to NERC. This standard contains requirements to provide data to Transmission Planners. Any procedures developed by an ROT or ISO are in addition to NERC standards. The same data may possibly satisfy both. It is up to the individual entities to determine whether or not this is the case.	
Utility Services	Utility Services suggests the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the standard and the associated Implementation Plans. Given our recent experience in other standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases, percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings.
Response: The GVSDT thanks you for your comments. The GVSDT has added a note to provide clarification: "Note: The	

Organization	Question 3 Comment
verification percentage above is based on the number of applicable units owned.	
PSEG	We voted “Negative” on this standard the reasons shown below: This FIRST COMMENT was provided for MOD-025-1, MOD-026-1, MOD-027-1, and PRC-019-1.1.SYNCHRONOUS CONDENSERS: The GVSDT is not working as a “team” with regards to synchronous condensers owned by TOs. The team working on this standard and PRC-019-1 INSIST that they be included as “applicable facilities,” while the team working on MOD-026-1 has stated otherwise. We provided this comment to the MOD-026-1 team in the last set of comments:”The exclusion of synchronous condensers (and other reactive devices) in MOD-026-1 per the rationale provided in the Background (with which we agree) states “Synchronous condensers are not currently addressed in the NERC Registry Criteria” However, companion standards under Project 2007-09 (MOD-025-2 and PRC-019-1) are applicable to synchronous condensers. The GVSDT should address this inconsistency.”The SDT responded as follows:”The SDT believes that MOD-026 is different from the other standards with respect to synchronous condensers due to the complex interaction required between the Transmission Planner and the Generator Owner, and thus believes it better to wait for efforts by others to define where synchronous condensers fit in the functional model.”In response to a similar comment on MOD-025-2 and PRC-019-1, we received these responses: MOD-025-1: “The GVSDT thanks you for your comment. There was overwhelming industry support (approximately 96%) for inclusion of synchronous condensers at the first posting of MOD-025-2. The Definition of Bulk Electric System (BOT Adoption Jan 2012) includes in “I5 - Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I2.”PRC-019-1: “The SDT feels that it is appropriate to include synchronous condensers because of their similarity to generators in terms of dynamic reactive power supply, voltage control, disturbance response, control functions, and protection systems. For this reason the SDT proposes to apply to the standard to similar size generators and synchronous condensers.” We need to see “one” statement from the SDT on the inclusion or exclusion of synchronous condensers that makes sense technically, and soon. **Response: The GVSDT is indeed working as a “team” with these standards. Each individual standard was developed based on the reliability needs and benefits that each specific standard**

Organization	Question 3 Comment
	requires. There are fundamental differences in the types of verifications required under each standard. Therefore, the reliability needs for each standard will not necessarily be the same, nor will the applicable facilities necessarily be the same. As you are the only commenter that has raised an issue regarding the applicability of synchronous condenser, the GVSDT concludes that stakeholder consensus has been achieved with respect to the inclusion of synchronous condensers in MOD-025-2. This SECOND COMMENT was provided for MOD-025-1, MOD-026-1, MOD-027-1, and PRC-024-1.2.DATA SHARING POLICY: For all of the MOD standards in this, only Transmission Planners are the recipient of the data developed. We asked that the standard require that the TP be required to share the data with others. The response we received is that the Functional Model requires the TP to share data with the TOP. Unfortunately, the Functional Model is unenforceable. We note that in PRC-024-1 R6 requires the GO to share its data with the RC, PC, TOP, and TO, upon request. Unless the same data is shared across all "modelers," the result will be outdated data in someone's model, which can have a bad result. The team should have one broad "data sharing" policy in the three MOD standards and PRC-024-1. Since the TP receives data in three of the standards, we suggest this language or similar language: The GO shall provide data to its TP within 60 days of its development [describe the data]. The TP shall provide the same data to any RC, PC, TP, or TOP within 60 days of receiving a request for it. **Response: The GVSDT has written the requirements of this body of standards based on the NERC Reliability Functional Model. The requirements of Reliability Standards MOD-010-0. MOD-011-0, MOD-012-0 and MOD-013-1 address the requirement for steady state and dynamic models (which are planning models) and the dissemination of these models to appropriate entities. The data to build Real-time models that are necessary for reliability and used by Reliability Coordinators and Transmission Operators are addressed in standards IRO-010-1a and TOP-003-2 respectively. The GVSDT does not see any reason to include duplicative requirements in this standard.**
Response: The GVSDT thanks you for your comments. Please see responses above.	
PPL Corporation NERC Registered Affiliates	Without some exemption, we disagree with the GVSDT linking generator applicability of this standard to the Compliance Registry Criteria. Instead, the approach to applicability should be the

Organization	Question 3 Comment
	same as what is used/proposed in MOD-026 and MOD-027 (i.e. in the Eastern Interconnection, individual units greater than 100 MVA directly connected to the BES, etc.) Other than that size unit, use regional criteria to address any smaller units identified as critical to the BES in a given region. Consistency of criteria among the standards within this Project 2007-09 should be the same.
Response: The GVSDT thanks you for your comments. The GVSDT has developed the applicability of MOD-025-2 based on the registration criteria. Each individual standard in this project has been developed based on the reliability needs and benefits that each specific standard requires. There are fundamental differences in the types of verifications required under each standard. Therefore, the reliability needs for each standard will not necessarily be the same, nor will the applicable facilities necessarily be the same.	
Xcel Energy	Xcel Energy questions the reliability value of determining the maximum leading reactive power value at maximum real power output. This is not an operating regime for most generating units, so operational data will not be available, and operating at maximum power would normally occur during higher system load conditions when the loss of a generating unit due to a mistake during a test would stress the system more severely.
Response: The GVSDT thanks you for your comments. During the comment period of June 15 – July 15, 2011 of MOD-025-2, the SDT asked the following question: **"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."** **The majority of stakeholders agreed with the proposed points. A note was added to Attachment 1 to address comments regarding leading capability: "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."** **To minimize stress to the system, the following is included in Attachment 1 – "If the Reactive Power capability is verified through**	

Organization	Question 3 Comment
test, it is to be scheduled at a time advantageous for the unit being verified to demonstrate its Reactive Power capabilities while the Transmission Operator takes measures to maintain the plant's system bus voltage at the scheduled value or within acceptable tolerance of the scheduled value." **The GVSDT believes that stakeholder consensus has been reached on this issue.**	

END OF REPORT