NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

Phase III–IV Standard Drafting Team Meeting
Wednesday, September 7, 2005 — 8 a.m.–5 p.m.
Thursday, September 8, 2005 — 8 a.m.–5 p.m.
Embassy Suites
901 North First St.
St. Louis, MO
314-241-4402

AGENDA

1. Introductions & Anti-trust
2. Review Meeting Format:
   - Documents will be reviewed by the entire drafting team, stopping only where there is an identified issue needing correction or clarification prior to posting
3. Review Meeting Objectives:
   - Finalize edits to all of the following documents for Set Two of the Phase III–IV Standards so they can be posted as soon as the SAC authorizes posting:
     - Standards and Red Line to either V0 or 1st Draft
     - Consideration of Comments
     - Implementation Plan
     - Comment Form
4. Review standards in the following order, followed by the associated ‘consideration of comments’ stopping to address any identified issue:
   - MOD-026, MOD-027
   - EOP-005
   - VAR-001 through VAR-003
   - MOD-016
5. Review the Implementation Plan, stopping to address any identified issue (**Attachment 1**).
6. Develop a comment form, starting with the questions already formed (**Attachment 2**).
7. Future meetings.

Implementation Plan — Set Two of Phase III & IV Reliability Standards

Effective Date

The following table shows the proposed effective dates for the standards in the 2nd of 2 sets of Phase III & IV Standards. Each of these standards has a unique effective date, based on the amount of preparation needed to comply with the requirements. The effective date is contingent on stakeholder support during the second posting of the standards, followed by approval of the reliability standards by a vote of the ballot pool in February, 2006. The effective date is also contingent on adoption of these Standards by the NERC Board of Trustees. The Board will approve the final effective date when it adopts the standards for implementation. This subset of the Phase III & IV standards is tentatively scheduled for consideration by the Board on May 1, 2006.

Standard	Proposed Effective Date	Reason for Delay in Implementation
EOP-005 System Restoration Plans	7/1/2006	
VAR-001 Voltage and Reactive Control	1/1/2007	
VAR-002 Generator Operation for Maintaining Network Voltage Schedules	1/1/2007	
VAR-003 Assessment of Reactive Power Resources		
MOD-016 Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management	7/1/2006	Time needed for RRO to modify & distribute existing procedures

Compliance with Phase III & IV Reliability Standards

Once the Phase III & IV Reliability Standards are effective, the responsible entities identified in each of the standards must comply with the requirements in that standard. The table in Appendix A maps all the Phase III & IV requirements to each applicable function in the Functional Model. Note that some Phase III & IV Reliability Standards are modifications of existing Version 0 Standards. Entities must continue to comply with all requirements in approved Version 0 Standards until the requirements in the approved Version 0 Standards are replaced or retired. For example, PRC-003-1 is a modification of Version 0's PRC-003-0. PRC-003-0 has two requirements for the Regional Reliability Organization. The Regional Reliability Organization is responsible for compliance with both of the requirements in PRC-003-0 until May 1, 2006 when PRC-003-1 will replace PRC-003-0.

Standard Number	Req. Number	BA	DP	GO	GOP	LSE	PA	PSE	RC	RP	RRO	RSG	TO	TOP	TP	TSP	NERC_Net

Standard Number	Req. Number	BA	DP	GO	GOP	LSE	PA	PSE	RC	RP	RRO	RSG	TO	TOP	TP	TSP	NERC_Net

Standard Number	Req. Number	BA	DP	GO	GOP	LSE	PA	PSE	RC	RP	RRO	RSG	TO	TOP	TP	TSP	NERC_Net

Standard Number	Req. Number	BA	DP	GO	GOP	LSE	PA	PSE	RC	RP	RRO	RSG	TO	TOP	TP	TSP	NERC_Net

Standard Number	Req. Number	BA	DP	GO	GOP	LSE	PA	PSE	RC	RP	RRO	RSG	TO	TOP	TP	TSP	NERC_Net

Standard Number	Req. Number	BA	DP	GO	GOP	LSE	PA	PSE	RC	RP	RRO	RSG	TO	TOP	TP	TSP	NERC_Net

COMMENT FORM FOR DRAFT TWO OF SET TWO OF PHASE III & IV STANDARDS

Please use this form to submit comments on the Phase III & IV Drafting Team's second draft of the first set of Phase III & IV Standards. Comments must be submitted by **November 30, 2005.** You must submit the completed form by emailing it to sarcomm@nerc.com with the words "Phase III & IV Standard Comments" in the subject line. If you have questions please contact Mark Ladrow at mark.ladrow@nerc.net or 609.452.8060.

ALL DATA ON THIS FORM WILL BE TRANSFERRED AUTOMATICALLY TO A DATABASE.

DO: **Do** enter text only, with no formatting or styles added.
Do use punctuation and capitalization as needed (except quotations).
Do use more than one form if responses do not fit in the spaces provided.
Do submit any formatted text or markups in a separate WORD file.

DO NOT: **Do not** insert tabs or paragraph returns in any data field.
Do not use numbering or bullets in any data field.
Do not use quotation marks in any data field.
Do not submit a response in an unprotected copy of this form.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
Email:		
NERC Region		**Registered Ballot Body Segment**
☐ ERCOT ☐ ECAR ☐ FRCC ☐ MAAC ☐ MAIN ☐ MAPP ☐ NPCC ☐ SERC ☐ SPP ☐ WECC ☐ NA - Not Applicable	☐	1 - Transmission Owners
	☐	2 - RTOs, ISOs, Regional Reliability Councils
	☐	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

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact Email:

Additional Member Name	Additional Member Organization	Region*	Segment*

* If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background:

The Phase III & IV drafting team divided its Standards into two sets, and is posting the second set now. (Set One was posted from September 1 through October 15, 2005.)

The Standards included in this second set are:

Major Changes to this Set of Phase III & IV Standards

Generator Model and Data Verification:

There were many suggestions for modifying the sequence of standards that include MOD-023 through MOD-027. MOD-023 required the RRO to develop procedures requiring Generator Owners to verify the following types of data used in modeling and for real-time analyses:

- Generator gross and net real power capability
- Generator gross and net reactive power capability
- Excitation system models and related data
- Speed/load governor control models and data

MOD-023 referenced four companion standards:

- MOD-024 requires the Generator Owner to verify (and report to end users) its generator gross and net real power capability
- MOD-025 requires the Generator Owner to verify (and report to end users) its generator gross and net reactive power capability
- MOD-026 requires the Generator Owner to verify its excitation system models and related data
- MOD-027 requires the Generator Owner to verify its speed/load governor control models and data

To prepare the second draft of this set of standards, the Drafting Team subdivided the Regional Reliability Organization's requirements in MOD-023 and added the requirements into the associated standard (MOD-024 through MOD-027). Now each of the revised standards includes the Regional Reliability Organization's requirement to develop a procedure and the Generator Owners requirement to follow that procedure.

One of the reasons the drafting team made this change was to make the balloting easier and to ensure that field testing of some measures won't hold up the entire sequence of standards.

Field Testing:

Most of the comments submitted on field testing indicated either a need to delay full implementation of the standards to give entities time to acquire and install equipment or to develop processes to meet compliance. These are not necessarily reasons to conduct field testing. The drafting team used these comments to draft effective dates for the individual standards that reflect consideration of the time entities need to acquire and install equipment or to develop processes to meet compliance.

The drafting team asks you to consider your acceptance of the changes made to the standards as you respond to the following questions. Note that you are not required to answer all of the questions.

Please Enter All Comments in Simple Text Format.

Insert a "check' mark in the appropriate boxes by double-clicking the gray areas.

1. Please identify anything you believe needs to be modified before this set of standards is field tested:
   - MOD-026-1 — Verification of Generator Excitation Systems and Voltage Control Model Data
   - MOD-027-1 — Verification and Status of Generating Unit Frequency Response

   ☐ Comments:

2. Please identify anything you believe needs to be modified before this set of standards is balloted:
   - EOP-005-1 — System Restoration Plans

   ☐ Comments:

3. Please identify anything you believe needs to be modified before this set of standards is balloted:
   - VAR-001-1 — Voltage and Reactive Control
   - VAR-002-1 — Generator Operation for Maintaining Network Voltage Schedules
   - VAR-003-1 — Assessment of Reactive Power Resources

   ☐ Comments:

4. Please identify anything you believe needs to be modified before this set of standards is balloted:
   – MOD-016-1 — Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management

   ☐ Comments:

5. Do you agree with the proposed implementation plan? If no, please identify specifically what you feel needs to be modified.

   ☐ Yes

   ☐ No

   ☐ Comments:

6. Please provide any other comments on this set of standards that you haven't already provided.

   ☐ Comments:

Some Issues for Discussion Sept 7-8

MOD-026 – Standard
The standard was modified to include the associated requirements for the RRO to develop the procedure (from MOD-023)

R1.2 – are the methods of verification all appropriate?

R1.4 through R1.4.8 - Should we organize this section like we did in MOD-025?

MOD-025 R1.5 Information to be reported:

R1.5.1 Verified maximum Reactive Power capability (both lagging and leading) at Seasonal gross and net Real Power generating capabilities as reported in accordance with Reliability Standard MOD-024 Requirement R1.5.1.

R1.5.2 Verified Reactive Power limitations, such as generator terminal voltage limitations, shorted rotor turns, etc.

R1.5.3 Verified Reactive Power of auxiliary loads.

R1.5.4 Method of verification, including date and conditions.

R1.4.4 and R1.4.5 need some adjectives in front of them. You don't report line drop compensators, you report some data related to line drop compensators. I don't know enough about gains and time constants to know if this information is complete or not.

Is R4 still needed? This requires the GO to report data prior to and after in-service dates, but the revised R1.3 requires the RRO to address periodicity and schedule for reporting data.

MOD-026 - Consideration of Comments
See suggested changes embedded in file.

MOD-027 - Standard
The standard was modified to include the associated requirements for the RRO to develop the procedure (from MOD-023)

Same comments as for MOD-026 about methods of verification and organization of the list of data

MOD-027 - Consideration of Comments
See suggested changes embedded in file.

EOP-005 – Standard

R1 – consider changing the word, 'must' with 'shall'

R1.8 – consider replacing the word, 'function' with 'task'

R9. – the following phrase is confusing since maintaining diagrams is a subset of documenting …

. . . shall document the Cranking Paths or maintain Cranking Path diagrams . .

Suggest this be modified to say: … maintain its documentation of Cranking Paths . .

Levels of non-compliance – Changed format based on a comment suggesting improved standardization of format – also removed 'or diagrams'

EOP-005 – Consideration of Comments

Numerous format changes to modify the 'tone' from one of the drafting team deciding what is best for the industry to one where the drafting team is using the suggestions from the industry to guide its changes.

Many of the changes made to EOP-005 modified V0 Requirements and the need for these changes isn't clear. These are the source measures that were to be added to EOP-005:

IVAM2 - Demonstrate through simulation or testing that a blackstart generating unit can perform its function.

IVAM3 - Diagram the number, size, and location of system blackstart generating units and the initial transmission switching requirements.

Page 1 – SPP
Commenter asks you to remove the word, 'applicable' – response indicates you moved a missing attachment into the standard but response doesn't address the use of the word, 'applicable' and the word 'applicable' is in the revised standard.

SPP & IDWG
Both sets of commenters suggested changing the title from System Restoration Plans to System Restoration. The requirements address having a plan as well as testing the plan **and** restoring the system (no reference to using the plan in this sequence of requirements). Why not change the title to System Restoration which is more comprehensive than System Restoration Plans?

Page 2 – Dynegy
Commenter suggests the standard should have some applicability to Generator Owners, and response indicates R4 does include coordination with between TOP and GOP but R4 doesn't mention either GO or GOP – none of the requirements include the words GOP or GO. Response must be changed.

Page 2 – Arkansas
Response to second comment – what change was made?

Page 3 – FRCC
Incomplete response provided to first comment.

Page 5 – Con Ed
The comment indicates there was an incomplete translation – the response says you made changes based on the comment, but the change made was to delete the 'incomplete' requirement because it was redundant**.** Of the two similar requirements, the one that was dropped was the one that included specific language about blackstart testing. Suggest you add the specificity regarding blackstart testing to the original requirement (R7) and revise responses accordingly.

Several commenters asked for additional clarification on the term, 'Startup Function' and the comment was not addressed.

Page 7 - Pacific Gas & Electric – need to provide missing responses

Page 9 – Don Griffith – no response provided to his last 2 comments – review draft responses

Page 10 – Gerald Rheault – no response provided to 2nd, 3rd and last comments – review draft responses

Page 13 – Resource Issues Subcommittee – no response provided to 1st comment – review draft response

VAR-001 – Standard

R3 is confusing as written – it leads the end user to believe that there is a single procedure that defines the elements referenced in R4, R6, R11, and R12. It seems more likely that these separate requirements may be addressed in several procedures. Suggest the following revision: (Note that it isn't clear why the parenthetical phrase is needed, since nuclear units are a subset of all generating units.)

R3. The Transmission Operator shall specify ~~exemption~~ criteria ~~for~~ that exempts generating units ~~in the development of~~ from compliance with the procedures ~~as~~ defined in VAR-001 R4, R6, R11, and R12 ~~(including any that may apply to nuclear units)~~. (DO YOU WANT THIS IN A SINGLE DOCUMENT OR IN EVERY PROCEDURE?)

R6.1 – suggest removing the phrase, 'as necessary'

R10.1 is unclear – what entity is the recipient of the GOP's summary report?

R10.2 is unclear – does the GOP retain the log or provide the log to some other entity? Note that in the Consideration of Comments your response to NIPSCo (Page 1) indicates that the GOP provides the log to the TOP.

VAR-001 – Consideration of comments

Page 1 – NIPSCO

The response seems incorrect. R10 doesn't include any requirements to provide the information to the TOP – R10 requires the GOP to retain documentation for 12 months. The corresponding standard (VAR-002) merely requires the GOP to 'maintain' the log – VAR-002 doesn't require the GOP to provide the log to the TOP – the associated measure in VAR-002 states that the GOP shall 'have available on request' the log.

Page 2 – First Energy Solutions

Response is incomplete and comment seems to be related to a different standard.

Page 3 – Dynergy –

Response seems incomplete. Commenter suggested that there be a requirement added to have the TOP provide a procedure in VAR-001 to address the following requirement in VAR-002:

VAR-002 R3. Each Generator Operator shall report within 30 minutes (or within the mutually agreed to timeframe with the Transmission Operator) to its Transmission Operator when a voltage and reactive schedule for a generator is not maintained.

> **R3.1** Each Generator Operator shall maintain a written log of the date, time, duration, reason, and time of notification to the Transmission Operator, and their concurrence for each period when a voltage schedule or reactive schedule was not maintained. This information shall be maintained for 12 rolling months.

VAR-001 R 4.2 Each Transmission Operator shall develop a procedure for communicating to the Transmission Operator failure to maintain a voltage or reactive schedule by a Generator Operator in accordance with VAR-002 Requirement 3.

Suggest modifying VAR-001 R4.2 to state:

VAR-001 R4.2 Each Transmission Operator shall develop a procedure that identifies what information the Generator Operator must provide to the Transmission Operator when the Generator Operator cannot maintain a voltage or reactive schedule including the following:

> **R4.2.1** The Generator Operator shall report to the Transmission Operator within 30 minutes (or within the mutually agreed to timeframe with the Transmission Operator) to of the time that the Generator Operator fails to maintain a voltage and reactive schedule.

> **R4.2.2** The Generator Operator shall maintain a written log of the date, time, duration, reason, and time of notification to the Transmission Operator, and the Transmission Operator's concurrence for each period when a voltage schedule or reactive schedule is not maintained. The Generator Operator shall maintain this information for 12 rolling months.

Page – 4 – Duke Energy

Response does not seem to address the comment which was that the phrase, 'shall know' is not a requirement. Consider replacing, 'shall know' with 'shall monitor'

> The Transmission Operator shall know the status of all transmission Reactive Power resources, and develop procedures to be given to the Generator Operator on communicating the status of voltage regulators and power system stabilizers.

Page 5 – TVA

Response to comment regarding the use of the word, 'auxiliary' is not complete – its not enough to say we considered your comment, you must state how you changed the associated document.

Page 6 – IDWG

The response to the first comment indicates there are planning elements to VAR-001. What are these – all the requirements look like they are performed in the operating horizon and are aimed at operations, not planning.

Page 8 - Joe Willson

The commenter is correct – R4.1 requires the TOP to maintain a list of synchronous generators that are required to follow a voltage or reactive schedule – level 2 non-compliance penalizes the TOP that doesn't have a list of generators exempt from this requirement. Suggest you modify the response to the comment. The revised standard's R3 requires the TOP to have a list of exemptions.

Response to comment regarding Level 3 isn't correct. Level 3 was assessing the completeness of the directive, not the documentation. (Note that this is at least the third comment suggesting that you state more clearly what you consider to be a voltage schedule)

Response to last comment doesn't necessarily match the standard. The standard isn't clear if the exemptions need to be provided in the individual procedures or in some other document.

Page 11 – FRCC

Another comment suggesting that voltage or reactive schedule needs to be defined.   What is the drafting team's basis for stating that it doesn't need to be defined when so many people have indicated that it does need to be defined?

The commenter suggests you've used different phrases to mean the same thing and you respond that you believe you have been consistent – however the commenter is correct:

- R4, R4.1, R4.2, M1 and Level 3 non-compliance all use the phrase 'voltage or reactive schedule.'
- R4.3 uses the phrase, 'voltage schedule deviation' leaving the reader unclear if a deviation in a reactive schedule must also be reported.
- R6.1 uses the phrase, 'voltage schedule or Reactive Power schedule'.

Page 15-17 – Transmission Subcommittee

Second comment seems to make sense. What's the basis for saying, 'there was minimal support for this change from the industry'? The TS suggested that the bulleted item is really the more comprehensive than the element it is qualifying and provided an alternate method of presenting the same information. They suggested that you change the original text:

4. Each Transmission Operator shall specify a voltage or reactive schedule to be maintained by each synchronous generator, within the reactive capability of the unit, at a specified bus and shall provide this information to the Generator Operator.

4.1 Each Transmission Operator shall maintain a list of synchronous generators that are required to follow a voltage or reactive schedule and shall provide each Generator Operator with its voltage or reactive schedule.

It looks like the information highlighted in yellow is redundant and could be combined as suggested by the TS.

VAR-002 – Standard

Purpose – suggest you use phrase, 'within equipment rating' rather than 'up to equipment capabilities' so this standard uses same language used in other standards.

R3 – the parenthetical phrase doesn't seem to be very realistic. The commenters who suggested this be changed indicated that 30 minutes is not a realistic timeframe given everything the GOP is required to do – the parenthetical indicates that the GOP and TOP will discuss some alternate time period and agree to some alternate time period for this reporting – how and when will this take place – will it be in one of the procedures the TOP writes for the GOP or will they negotiate on a case by case basis in real time?

R4.1 The addition of this subrequirement seems to tell the GOP how to do its routine job – and its purpose in this standard is unclear. Shouldn't the GOP always consider the impact of any change to any of the equipment under the GOP control before taking action?

Non-compliance
It isn't clear if the levels of non-compliance are being accumulated by each generator or not. Would the compliance monitor actually look at all operating logs for each generator on the system for a whole year to come up with these figures – or should the reporting period and compliance reset period be something shorter?

Level one and level two non-compliance are redundant unless modified to include a range of hours for level two as follows:
… for an accumulated time of 8 or more unit-hours but less than 16 unit-hours . . .

Level three non-compliance should be modified as follows:
… for an accumulated time of 16 or more unit-hours but less than less than 24 unit-hours

Level four non-compliance should be modified as follows:
… 24 or more unit-hours . . .

VAR-002 – Consideration of Comments

P1 – Dynegy
Response suggests you'll modify TOP-002 – this needs to be in the implementation plan and a red line to show the changes to TOP-002 is needed.

P3 – NIPSCO
Response to first comment doesn't provide sufficient information to understand the intent of the response.
Response to third comment isn't specific enough to tell the commenter what was changed.

Page 4 – Dynegy
Response to first comment is inaccurate – response indicates the Drafting Team made a change to the 30 minutes in R1.1 and R3, but no such change was made to R1.1 or to R3. A change was made to R3, but the change isn't the one that was requested.

Response to second comment does not address the suggestion and needs to be modified. The commenter is suggesting that voltage schedules be specified as 'ranges' and is suggesting that the 'reactive' component be removed – and response is addressing responsibility. . .

Response to last comment doesn't reflect any consideration of the comment. What is the DT's basis for thinking that commenters agree with the levels of non-compliance?
Page 4 – IDWG
Response to comment indicates you adopted suggested change to R4, but the change wasn't made. This needs to be corrected either in the response or in the standard.

Page 5 – Resources Subcommittee
Most responses are incomplete and need more work.

Comment suggests eliminating all references to auxiliary transformers and response implies this was done, but the term remains in R5, M3 and in level one non-compliance. The response or the standard needs modification.

Response to last comment doesn't address the stated concern and provides no clarification.

Page 6 – Southern Co
First comment suggests you add the words, 'on request'' to 1.3 – response indicates you made the change, but the words, 'on request' don't appear in 1.3. Need to change response.

Page 6 – Second set of comments from Southern Co
Second comment seems to have been totally ignored and this is the second comment asking for clarification as to what you envision the GOP is monitoring – grid voltage or the GOP's adherence to a voltage schedule

Page 11 – TIS
Second comment – response doesn't seem to address the comment and there is no indication that R1 was changed as suggested – either change the standard or the response.

Page 11 – Ontario
No response provided to comment suggesting there may be an operational issue with R2.

Page 12 – Transmission Subcommittee
Response to first comment indicates support for comment, but not all the suggested changes were made to R2 – the TS suggested 'as specified' be replaced with 'as directed' and this change was not made. Either change the response or the standard.

Response to second comment indicates the members of the RS are wrong and the DT is right – but the RS is really asking for clarification, and this is not the only group that indicated there is a need for clarification in identifying when the 30 minutes starts. This needs some discussion.

Third comment indicates that 'on request' should be clarified. In most other standards, the phrase, 'on request' actually states, 'on request (within 30 calendar days)'. This is what the TS was suggesting. Compared to other standards, this one is unclear in identifying how you would measure 'on request'.

VAR-003 – Standard

Need to confirm the effective date of April 1, 2006 (none was recorded on Action Plan)

VAR-003 – Consideration of Comments

No responses provided to comments - I drafted what I could, so please be prepared with constructive criticism and suggestions for answers that are missing.

MOD-016 - Consideration of Comments

The responses, in many cases, are not accurate. The comments request changes to several of the 'new' requirements, and the responses indicate (incorrectly) that the requirements are from V0. V0 had just the following two requirements – everything else was added by the drafting team:

R1. The Planning Authority and Regional Reliability Organization shall have documentation identifying the scope and details of the actual and forecast (a) Demand data, (b) Net Energy for Load data, and (c) controllable DSM data to be reported for system modeling and reliability analyses.

R1.1. The aggregated and dispersed data submittal requirements shall ensure that consistent data is supplied for Reliability Standards TPL-005-0, TPL-006-0, MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-0, MOD-014-0, MOD-015-0, MOD-016, MOD-017-0, MOD-018-0, MOD-019-0, MOD-020-0, and MOD-021-0.

R2. The documentation of the scope and details of the data reporting requirements shall be available on request (five business days).

Page 2 – Comment from Con Ed and others – response is not correct – R1.5 was not part of V0, it was added by the Drafting Team

Page 4 – Comment from ATC – response is not correct – R1.3 was not part of V0 and making changes is not outside the scope of the SAR

Page 6 – Comment from Entergy – response is incorrect – R5 was added by the drafting team, it was not part of V0

<table>
<tr><th>Commenter</th><th>Reliability Need</th><th>Acceptable Translation</th><th>Comments</th></tr>
<tr><td>Entergy</td><td></td><td></td><td>(From Q 4 – Other comments)

The two Measures included in this Standard are concerned only with Rquirement 11. A third measure should be added to measure R1 - R10.

The wording in the Data Retention part of the Compliance Section seems appropriate: "The Transmission Operator must have its plan to reestablish its electric system available for review by the Regional Reliability Organization at all times."</td></tr>
<tr><td colspan="4">Response: ~~The drafting team believes that m~~Measure #1 addresses R8 and R9 and~~ that~~ M2 addresses R10. The other requirements were part of the existing V0 standard and adding measures for these requirements is outside the scope of this SAR.</td></tr>
<tr><td>SPP Transmission Working Group</td><td>Yes</td><td>No</td><td>Title should be changed to System Restoration because standard covers more than restoration plan, includes policy portions in R11.

Applicable to TPs and PAs.

R1-remove APPLICABLE, each plan should address all of the elements of EOP5. If they apply simply states it.</td></tr>
<tr><td colspan="4">Response: ~~The drafting team believes t~~The term “system restoration” encompasses more than what is contained within this standard~~, and~~ therefore~~ believes~~ the present title is more appropriate.

~~-~~The comment provided does not provide the drafting team with sufficient information concerning applicability to Transmission Planners and Planning Authorities to determine whether they should be included in the standard.

The drafting team ~~has review~~reviewed the subject sentence and has discovered the posted standard inadvertently omitted ~~the~~ attachment 1 that described the plan elements. The drafting team incorporated the contents of attachment 1 directly into the standard ~~directly~~.</td></tr>
<tr><td>NERC Interconnection Dynamics Working Group</td><td>Yes</td><td>No</td><td>The title should be: System Restoration, because the standard covers more than just the plan, it includes the policy portions in R11.

— R1-R10 Restoration Plan – needs better organization, change the order to: Plan elements, Plan Coordination, Plan validation, Plan Review & Update, and</td></tr>
</table>

			Plan Training. — Add applicability to Transmission Planners and Planning Authorities.
Response: The drafting team believes the term "system restoration" encompasses more than what is contained within this standard and therefore believes the present title is more appropriate. The comment provided does not provide the drafting team with sufficient information concerning applicability to Transmission Planners and Planning Authorities to determine whether they should be included in the standard. The ~~drafting team believes the content of the standard is appropriate and the~~ order of presentation is subjective.			
Gred Mason – Dynergy Generation	Yes	No	1.Need to include Generation Owners in Section 4(Applicability). 2.Generation Owners should be included in Section B,R4. 3.In Section B,R9 need to eliminate "its" wording as TO's may not own blackstart generating units. 4.In Section B,R10 need to change "or" in second line to "and" and change "units to be cranked" in fourth line to "units to be started."
Response: 1 & 2: While the~~The drafting team believes the~~ Transmission Operator and Balancing Authority do need to ~~should also~~ coordinate their actions with other entities, including Generator Operators, ~~with~~ it is the Transmission Operators and Balancing Authorities that are responsible for the restoration-related tasks addressed in this standard. ~~the Generation Operator and has included this in the standard (R4.). However, for the purpose of the standard itself, the drafting team believes this standard is not applicable to Generator Owners or Generator Operators. The purpose of this standard is for the Transmission Operator and Balancing Authority to have a restoration plan.~~ 3: The drafting team reviewed section B R.9 and discovered this requirement is redundant with R7~~.~~ of the same standard along with EOP-009-1~~. The drafting team recommends~~ and deleted~~ion of~~ Requirement R.9. 4:~~ The drafting team agrees to the proposed change in phrase "units to be cranked" in fourth line to "units to be started. However,~~ T~~t~~he ~~drafting team believes the~~ intent of R10~~.~~ is to allow for one of two options in fulfilling this requirement, so changing, 'or' to 'and' ~~. The option included in R10. was~~ in response to earlier comments regarding Critical Utility Infrastructure. Your suggestion to change, 'units to be cranked' to 'units to be started' was adopted and is reflected in the revised standard.			

Ronnie Frizzell - Arkansas Electric Coop. Corp.	Yes	No	R1 -- remove applicable, each plan should address all of the elements of EOP5. If they don't apply simply state it. R12 -- By deleting R12 the requirement to have the unit available is lost. I know that it is not the TOs responsibility to make generation available, however, the TO does need to know that black start units are available if needed. Maybe this requirement should be in another standard
Response: The drafting team ~~has~~ reviewed the subject sentence and ~~has~~ discovered the posted standard inadvertently omitted ~~the~~ attachment 1 that described the plan elements. The drafting team incorporated the contents of attachment 1 directly into the standard ~~directly~~. The drafting team ~~agrees and has~~ modified R8~~.~~ to address your concern re R12.			
FRCC	Yes and No	No	References to EOP-005 Attachment in R1 needs to be deleted and the applicable elements need to be added into the requirements, including a requirement that the TOP must provide its plan to the RRO upon request. R2 should qualify the level of "changes in the power system network" that would require the Transmission Operator to review and update its restoration plan to ensure that R2 only requires the review and updates when network changes occur that could impact the restoration plans. R7 requires that the verification of the restoration procedures by actual testing or by simulation. Actual testing should be removed from the standard because "actual" testing of the restoration procedure is impractical since it would adversely impact customers. R8 should be the responsibility of the RRO and not of the individual Transmission Operators. References to EOP-005 Attachment in the Compliance section needs to be deleted.
Response: The drafting team ~~has review the subject sentence and has~~ discovered the posted standard inadvertently omitted ~~the~~ attachment 1 that described the plan elements. The drafting team incorporated the contents of attachment ~~1~~ 1 directly into the standard ~~directly~~.			

The drafting team modified R2. in response to your concern. The drafting team believes that actual testing is appropriately included in the standard. The drafting team modified R8~~.~~ in response to your concern. See first response to these comments.			
Mohan Kondragunta – Southern California Edison	Yes	No	To improve the standard translation, SCE recommends the following changes: For the definitions, rename the term “Cranking Path” to “System Restoration Critical Path” For R8, the requirement for a T.O. to verify blackstart sufficiency to meet RRO requirements is unreasonable. The T.O. should verify sufficient blackstart for their restoration plans or their ISO, not the RCC. As worded, Requirement R9 implies that the Transmission Operator owns the blackstart units in its system restoration plan which may not be the case. Therefore, change Requirement R9 to read: “… demonstrate, through simulation or testing, that the blackstart generating unit(s) in its restoration plan can perform…”
Response: ~~The drafting team received little support for this change and therefore recommends leaving the term as it exists~~Most commenters agreed with the definition and it wasn’t changed ~~currently~~. The drafting team modified R8~~.~~ in response to your concern. The drafting team reviewed section B R.9 and discovered this requirement is redundant with R7~~.~~ of the same standard along with EOP-009-1~~. The drafting team recommends~~and deleted~~ion of~~ Requirement R.9.			
Individual Members of CCMC	Yes	No	Measure contains additional requirements of supplying a document within 30 days – this is a requirement, move to R9 Levels of non-compliance do not cover R8. The level of Non-compliance use the words "element" and "requirement" but it is not clear what is intended, e.g. (1) does R8 contain 3 elements or is it an element and where is this defined and (2) is R8 concerned addressed if one or two of the three components included under R8 are addressed.

<table>
<tr><td colspan="4">
Response: The current format for NERC standards includes specifying the response time for providing evidence in the Measures of the standard.
The drafting team made modifications to the Compliance section to address this comment.
The drafting team ~~has review the subject sentence and has~~ discovered the posted standard inadvertently omitted the attachment 1 that described the plan elements. The drafting team incorporated the contents of attachment 1 into the standard directly and revised the levels of non-compliance so they reference specific ‘requirements’.
</td></tr>
<tr><td>Consolodated Edison</td><td>Yes</td><td>No</td><td>
IV.A.M2 has not been fully translated into R10 and measure M2.
The Measures should include other restoration plan measures, not only those related to blackstart.
In R9, it is important that serious consideration should be given to blackstart testing more frequently than "at least every five years."
The Drafting Team should clarify the term Startup Function in R9 to distinguish between simple blackstart of a unit(s) and the ability to perform restoration service.
We suggest to reformat the restoration plan requirements as separate bulleted subrequirements and then reformat the Blackstart unit testing section into subRequirements for clarity.
</td></tr>
<tr><td colspan="4">
Response: The drafting team has made significant changes to the standard in response to your comment regarding IV.A.M2.
Adding measures for the existing V0 standard’s requirements is outside the scope of this SAR. ~~This comment would require the drafting team to operate outside the scope of the current SAR.~~
The drafting team reviewed section B R.9 and discovered this requirement is redundant with R7~~.~~ of the same standard along with EOP-009-1 and deleted ~~. The drafting team recommends deletion of~~ Requirement R.9.
~~The drafting team believes the format of the standard is appropriate and is subjective~~Changing the sequence of requirements approved as part of V0 is outside the scope of what is necessary to incorporate the requirements for IVAM2 and IVAM3. .
</td></tr>
<tr><td>P.D. Henderson
Khaqan Khan</td><td>Yes</td><td>No</td><td>
IV.A.M2 and IV.A.M3 have not been fully translated into EOP-005 requirement R9, R10 and measure M2.
Moreover, the Measures should also include other restoration plan measures, not
</td></tr>
</table>

			only those related to blackstart. In R9, consideration should be given on testing of blackstart more frequently rather than "at least every five years". Simulation of unit testing should not be allowed and there should be a requirement to test any blackstart related facility on an annual basis. Drafting Team to expand the term Startup Function in R9 to require both a blackstart of a unit(s) and the ability to perform restoration service.
Response: The drafting team has made significant changes to the standard in response to your comment regarding IV.A.M2 and IV.A.M3. Adding measures for the existing V0 standard's requirements is outside the scope of this SAR. ~~This comment would require the drafting team to operate outside the scope of the current SAR.~~ ~~R9. This comment would require the drafting team to operate outside the scope of the current SAR.~~ The drafting team reviewed section B R.9 and discovered this requirement is redundant with R7~~.~~ of the same standard along with EOP-009-1. The drafting team recommends deletion of Requirement R.9.			
ISO/RTO Council Standards Review Committee Ed Riley – California ISO	Yes Yes	No No	IV.A.M2 and IV.A.M3 are not fully translated into R9 and R10 and measure M2. The Measures should include other restoration plan measures, not only those related to blackstart. Drafting Team to clarify the term Startup Function in R9 to distinguish between simple blackstart of a unit(s) and the ability to perform restoration service.
Response: The drafting team has made significant changes to the standard in response to your comment regarding IV.A.M2 and IV.A.M3. Adding measures for the existing V0 standard's requirements is outside the scope of this SAR. ~~This comment would require the drafting team to operate outside the scope of the current SAR. R9. This comment would require the drafting team to operate outside the scope of the current SAR.~~ The drafting team reviewed section B R.9 and discovered this requirement is redundant with R7~~.~~ of the same standard along with EOP-009-1. The drafting team recommends deletion of Requirement R.9.			
Cinod Kotecha	Yes	No	IV.A.M2 has not been fully translated into R10 and measure M2.

Michael C. Calimano – NYISO Kathleen Goodman – ISO-NE Alan Adamson – NYSRC NPCC CP9 RSWG	Yes Yes Yes Yes	No No No No	The Measures should include other restoration plan measures, not only those related to blackstart. In R9, it is important that serious consideration should be given to blackstart testing more frequently than "at least every five years". Simulation of unit testing should not be allowed and there should only be a requirement to test the Units at least once every five years and any blackstart related facility on an annual basis. Drafting Team to clarify the term Startup Function in R9 to distinguish between simple blackstart of a unit(s) and the ability to perform restoration service. Suggestion to reformat the restoration plan requirements as separate bulleted subrequirements and then reformat the Blackstart unit testing section into subRequirements for clarity.
Response: The drafting team has made significant changes to the standard in response to your comment regarding IV.A.M2 and IV.A.M3. Adding measures for the existing V0 standard's requirements is outside the scope of this SAR. ~~This comment would require the drafting team to operate outside the scope of the current SAR. This comment would require the drafting team to operate outside the scope of the current SAR.~~ The drafting team reviewed section B R.9 and discovered this requirement is redundant with R7~~.~~ of the same standard along with EOP-009-1. The drafting team recommends deletion of Requirement R.9. The drafting team believes the format of the standard is appropriate as shown and is subjective regardless.			
Kansas City Power and Light	Yes	No	The new R9 and R10 seem to be a rewording of the existing R7 and R8. One of these sets of requirements needs to be eliminated.
Response: The drafting team ~~has~~ made significant changes to the standard in response to your comment regarding R9~~.~~ and R10.			
Pacific Gas and Electric			COMMENT: R3 states "the Transmission Operator shall develop restoration plans with a priority of restoring the integrity of the Interconnection". R11.4 states "The affected Transmission Operator shall give high priority to restoration of off-site power to nuclear stations". These two statements could result in confusion in terms of priority (i.e. the Interconnection or offsite power to a nuclear station). Restoring offsite power to a nuclear station may not contribute to restoring the

			bulk power system and its interconnections, therefore, may be judged a lower priority by the Transmission Operator. The NRC expects the restoration of offsite power to a nuclear power plant to be the highest priority. COMMENT: R8 is too general regarding the capability of blackstart units. Blackstart unit capability should also be sufficient to meet nuclear offsite power requirements. COMMENT: R9 should require that documentation of simulation / testing acceptance be transmitted to the nuclear power plants. COMMENT: R10 Same comment as R9, documentation applicable to nuclear offsite power cranking paths should be provided to the nuclear power plants. COMMENT: R11.5.4 should specifically exclude nuclear offsite power from any load shedding.
Response: The drafting team ~~has~~ modified the standard to specifically reflect nuclear station's offsite power. The drafting team believes the additional comments have been adequately covered in the standard.			
Mark Kuras – MAAC	Yes	No	Several of the requirements (R2, R3) should be sub-requirements under the requirement to have a restoration plan (R1). Seems like too many requirements are included in this standard, break up the standard into more than one standard. Measurements do not align to the requirements. Many more measurements are needed and then need to be reflected in the levels of non-compliance. Level 2 mentions and Attachment. What is this? Suggest that a separate blackstart standard be created instead of trying to insert the Blackstart requirements in an imcomplete operating standard that needs a lot of work.
Response: The drafting team has made significant formatting changes to the standard. Adding measures for the existing V0 standard's requirements is outside the scope of this SAR. ~~The drafting team has made significant changes to the standard in response to your comment. The comment regarding measurements would require the drafting team to operate outside the scope of the current SAR.~~ The drafting team ~~has review the subject sentence~~			

~~and has~~ discovered the posted standard inadvertently omitted ~~the~~ attachment 1 that described the plan elements. The drafting team incorporated the contents of attachment 1 directly into the standard and revised the associated language in the levels of non-compliance ~~directly~~.			
Peter Burke – American Transmission Co.	Yes	No	V1 of this standard should be enhanced to include Measures that address all the Requirements R1--R11 comprising it. While the translation of IV.A.M2-M3 resulting in R8, R9, R10 and M1-M2 is acceptable, not fixing the pre-existing deficiencies (i.e. absence of any Measures) in the V0 standard makes the resulting EOP-005-1 an incomplete V1 revision.
Response: Adding measures for the existing V0 standard's requirements is outside the scope of this SAR. ~~The comment regarding measurements would require the drafting team to operate outside the scope of the current SAR.~~			
Xcel Energy – Northern States Power	Yes	No	Measure M1 - The intent of this measure is to validate the elements of the restoration plan, either by simulation or physical testing. Demonstration of the black-start units ability to perform the functions of the restoration plan is too restrictive, and conflicts with EOP - 009. Recommend this measure be written as follows: " The Transmission Operator shall , within 30 calendar days of a request, provide its Regional Reliability Organization with documentation of simulations or tests that demonstrate the resources (including cranking paths) identified in the Transmission Operator's restoration plan are sufficient to support its restoration plan." Measure M2 - Providing documentation can be interpreted as sending doucmentation off-site, which can be a conflict as this documentation is considered as Critical Utility Infrastructure information. This measure should be rewritten as "provide documentation or diagrams showing number, size and location of blackstart generating units identified in the Transmission Operator's restoration plan and the associated cranking paths for view at the Transmission Operator's location.
Response: M1 - The drafting team made changes to the draft standard to reflect your comment.			

M2 – Your suggestion was adopted and is reflected in the revised standard.			
Joseph D Willson – PJM	Yes	No	Level 4 2.4.2 goes beyond the elements of Requirement 9 The levels of non-compliance are difficult (and therefore subjective) to measure. Measure contains additional requirements of supplying a document within 30 days
Response: The drafting team ~~made changes to the draft standard to reflect your comment~~revised the levels of non-compliance so they align with the new requirements. The drafting team ~~has review the subject sentence and has~~ discovered the posted standard inadvertently omitted ~~the~~ attachment 1 that described the plan elements. The drafting team incorporated the contents of attachment 1 directly into the standard and added more specificity to the associated requirements that linked to specific levels of non-compliance ~~directly~~. The current format for NERC standards includes specifying the response time for providing evidence in the Measures of the standard. ~~The comment concerning the reporting timeline not an additional requirement but is used for compliance.~~			
Dan Griffiths – PA Office of Consumer Advocate	Yes	Yes	Generator testing frequency may be as much as 5 years under the proposed standard per Requirement 9. I believe that this is far too long given the critical function of system restoration. The need for more frequent testing is underlined by the fact that some Black Start generators in PJM, for example, do fail to start under normal operations. Also, there have been anecdotal comments in PJM regarding a lack of maintenance for some Black Start units. Thus, frequent testing ought to be done to ensure that Black Start resources are actually likely to be available. Almost every other standard in Phase III-IV has a reset period of 1 year and I urge that the retest period for "black start" generation be set to 1 year. Further, under 1.3 of Compliance, the proposed addition sets the record retention period to 3 years. This appears to conflict with the 5 year frequency of generator testing. Recommend, at a minimum, that all time frames in EOP-005-1 be alligned.
Response: The drafting team reviewed section B R.9 and discovered this requirement is redundant with R7~~.~~ of the same standard along with EOP-009-1. The drafting team recommends deletion of Requirement R.9. Generator testing requirements are addressed EOP-009-0.			

The performance reset period is one year. The data retention section of the standard does require the Compliance Monitor to retain audit data for three years, but does not require the responsible entity to retain its data for any specific period of time.			
Gerald Rheault – Manitoba Hydro	Yes	Yes	In items R5, R6 and R7, the required action frequency should be specified as a measurable amount. In R1 the attachment (Attachment 1-EOP-005-0) contained in EOP-005-0 should be included instead of just being referenced. R5: should clarify objective of the test of telecommunications facilities. R11.5.2: What is the intent of this requirement? Measures: Why wouldn't documentation of the restoration plan be a measurement? R1 requires a plan, but does not explicitly say you have to document it. The first sentence on part 5 "The Transmission Operator …at all times" requires a plan to be provided to the RRO. Why do we need 11 requirements if you are only going to measure compliance to two requirements?
Response: The drafting team notes items R5, R6, and R7 are original V0 requirements ~~approved therefore modification concerning action frequency~~and modifying these is outside the scope of the subject SAR. Attachment 1 was inadvertently omitted from the first draft of this standard. The drafting team added the language from Attachment 1 to the requirements in the standard as suggested. R5 already states that the telecommunication facilities to be tested are those that are needed to implement the restoration plan. The intent of R11.5.2 (currently R10.5.2) is to promote deliberate action in ~~typology~~ topology assessment prior to interconnection of isolated areas. The requirements of NERC standards are intended to enhance the reliability of the bulk electric system; documentation, although required, does not directly enhance the reliability, but is required for demonstrating compliance. ~~The drafting team has review the subject sentence and has discovered the posted standard inadvertently omitted the attachment 1 that described the plan elements. The drafting team incorporated the contents of attachment 1 into the standard directly~~Many of the			

requirements in this standard are from Version 0 and adding measures for existing requirements is outside the scope of the SAR.			
John K. Loftis, Jr. – Dominion – Electric Transmission Southern Company Generation Southern Company Transmission SERC EC Planning Standards Subcommittee (PSS) Entergy	Yes Yes Yes Yes Yes	Yes Yes Yes Yes Yes	Recommend that Level 3 non-compliance be made not applicable and the current Level-3 description be moved to Level-4 as 2.4.3.
Response: The drafting made this change to the draft standard.			
Midwest Reliability Organization	Yes	Yes	R5. The term "periodically" should be changed to some measurable frequency. R6 and R7 should have a required frequency added to the requirement. R1. Will need to remove reference to old version 0 document and create reference to new version 1 attachment 1.
Response: The drafting team notes items R5, R6, and R7 are original V0 approved therefore modification concerning action frequency is outside the scope of the subject SAR. The drafting team ~~has review the subject sentence and has~~ discovered the posted standard inadvertently omitted the attachment 1 that described the plan elements. The drafting team incorporated the contents of attachment 1directly into the standard ~~directly~~.			

Transmission Agency of Northern California	Yes	Yes	There appears to be a typo in Requirement R10. We suggest removing the word [associated] in the second line. In Requirement R9, Measure M1, and Level of Non-compliance 2.4.2, we suggest changing the word [simulation(s)] to [calculations]. In this context, simulations could lead some people to believe that powerflow studies need to be performed. However, in many cases, a simple hand or spreadsheet calculation may be all that is needed to show that the plan will work as designed.
Response: The word “associated” has been removed. The drafting team believes “simulation” includes calculations and therefore should not be modified.			
Doug Hohbough – First Energy Corp.	Yes	Yes	This analysis is best performed on a Dispatcher Training Simulator or similar computer model with dynamic capabilities containing the model of the system being studied. This may not be available to all members of the industry. Those organizations without this capability would be religated to the testing method which may or maynot be a viable option depending upons system configurations.
Response: Thank you for your comment.			
Rebecca Berdahll – Bonneville Power Administration Karl Bryan – Corp of Engineers Jay Sietz – US Bureau of Reclamation Brenda Anderson Deborah M. Linke – US Bureau of Reclamation	Yes Yes	Yes Yes	R4 We recommend adding blackstart generator owner to the list of entities with whom the transmission operator will coordinated the blackstart restoration plan. R9 We recommend changing "startup functions" to "system restoration functions" to avoid confusion with the requirement to periodically demonstrate the ability of blackstart generators to start without grid support.
Response: The drafting team believes the Transmission Operator should also coordinate with the Generation Operator and has			

included this in the standard (R4.). However, for the purpose of the standard itself, the drafting team believes this standard is not applicable to Generator Owners or Generator Operators. The drafting team reviewed section B R.9 and discovered this requirement is redundant with R7. of the same standard along with EOP-009-1. The drafting team recommends deletion of Requirement R.9.			
Karl A. Bryan - US Army Corps of Engineers	Yes	Yes	I think there also needs to be a requirement for the transmission operator to prove that the system restoration plan works as well as to prove that the blackstart generators are actually capable of energizing a line and picking up a load. My experience has been that blackstarting a generator is the easy step, it is picking up the transformer and transmission line charging currents that cause a generator the most problems.
Response: Physical testing of Blackstart generator capability is covered under EOP-009-0 and is no longer duplicated in this standard. The drafting team also believes that TO may not be able to test its plan by energizing a line and picking up a load due to system topology and reliability concerns therefore it maintains simulation as an acceptable alternative to physical plan validation per the standard.			
Resource Issues Subcommittee	Yes	Yes	1) In R11, Transmission Operators and Balancing Authorities should not take any action until coordination is made with their Reliability Coordinator(s). Suggest changing R11 to "Following a disturbance in which one or more area of the Bulk Electric System becomes isolated or blacked out, the affected Transmission Operators and Balancing Authorities shall begin immediately to implement the following steps:" 2) In Compliance Section 2.4.2, suggest deleting "regional".
Response: ~~BIG ISSUE. ~~R11 was approved, as written, in Version 0. Making the suggested change would change the intent of R11 and is outside the scope of the SAR. The drafting team disagrees with deleting the word regional because the TO's plan needs to be compliant with the regional plan.			
Tennessee Valley Authority	Yes	Yes	In "Levels of Non-Compliance" section 2.4.2, delete the word "regional."
Response: The drafting team disagrees with deleting the word regional because the TO's plan needs to be compliant with the regional			

plan.			
Transmission Issues Subcommittee	Yes	Yes	TIS has no additional comments.
PPL Corporation	Yes	Yes	
WECC Reliability Subcommittee	Yes	Yes	
Howard Rulf - WE Energies	Yes	Yes	
John Horakh – MACC	Yes	Yes	
Raj Rana – AEP	Yes	Yes	
Karl Kohlrus - City Water, Light & Power	Yes	Yes	
Carol L. Krysevig – Allegheny Energy Supply Co.	Yes	Yes	

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

This proposed standard is a translation of planning measure IV.A.M2 and IV.A.M3, which were not included in the approval Version 0 reliability standards because they required further work.

Development Steps Completed:

1. A SAR was posted from December 2, 2004, through January 7, 2005.
2. The SAC appointed a standard drafting team on January 13, 2005.
3. The drafting team posted its response to SAR comments and all other historical comments on April 19, 2005.
4. The drafting team posted Draft 1 of the standard on April 21, 2005 through June 13, 2005.
5. The drafting team has reviewed comments on Draft 1, prepared a consideration of those comments and made changes incorporated into Draft 2.
6. The drafting team posted Draft 2 on September 1, 2005.

Description of Current Draft:

This is ~~a first~~the second draft of the standard to be posted for industry comment.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Close Draft 1 comment period.	~~June 6~~October 15, 2005
2. Review comments from industry posting and determine if the draft standard is ready for ballot.	~~July 15~~October 31, 2005
3. Post for 30-day pre-ballot period.	~~August~~ November 1, 2005
4. Conduct ballot.	~~September~~ December~~1,~~ 2005
5. Post for 30-day period prior to Board adoption.	~~October 1~~January 6, ~~2005~~2006
6. Board adoption~~ and effective date~~.	~~November 1, 2005~~February 7, 2006
~~6.~~7. Effective date	April 1, 2006

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Cranking Path: A portion of the electric system that can be isolated and then energized to deliver electric power from a generation source to enable the startup of one or more other generating units.

A. Introduction

1. **Title:** **System Restoration Plans**

2. **Number:** EOP-005-1

3. **Purpose:** To ensure plans, procedures, and resources are available to restore the electric system to a normal condition in the event of a partial or total shut down of the system.

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

5. **Proposed Effective Date:** ~~November 1, 2005~~April 1, 2006.

B. Requirements

R1. Each Transmission Operator shall have a restoration plan to re-establish its electric system in a stable and orderly manner in the event of a partial or total shutdown of its system, including necessary operating instructions and procedures to cover emergency conditions, and the loss of vital telecommunications channels. The restoration plan must include ~~the r~~Requirements R1.1. through R1.9., as applicable:

R1.1. Plan and procedures outlining the relationships and responsibilities of the personnel necessary to implement system restoration.

R1.2. The provision for a reliable black-start capability plan including: fuel resources for black start power for generating units, available cranking and transmission paths, and communication adequacy and protocol and power supplies.

R1.3. The plan must account for the possibility that restoration cannot be completed as expected.

R1.4. The necessary operating instructions and procedures for synchronizing areas of the system that have become separated.

R1.5. The necessary operating instructions and procedures for restoring loads, including identification of critical load requirements.

R1.6. A set of procedures for simulating and, where practical, actually testing and verifying the plan resources and procedures.

R1.7. Documentation must be retained in the personnel training records that operating personnel have been trained annually in the implementation of the plan and have participated in restoration exercises.

R1.8. The functions to be coordinated with and among Reliability Coordinators and neighboring Transmission Operators. (The plan should include references to coordination of actions among neighboring Transmission Operators and Reliability Coordinators when the plans are implemented.)

~~R1.~~Notification shall be made to other operating entities as the steps of the restoration plan are implemented. ~~Each Transmission Operator shall include the applicable elements listed in EOP-005 in developing a restoration plan.~~

R1.9.

R2. Each Transmission Operator shall review and update its restoration plan at least annually and whenever ~~it makes~~ changes in the power system network occur that affect its restoration plan, and shall correct deficiencies found during the simulated restoration exercises.

R3. Each Transmission Operator shall develop restoration plans with a priority of restoring the integrity of the Interconnection with emphasis on restoring offsite power to nuclear stations.

R4. Each Transmission Operator shall coordinate its restoration plans with Balancing Authorities within its area, its Reliability Coordinator, and neighboring Transmission Operators and Balancing Authorities.

R5. Each Transmission Operator and Balancing Authority shall periodically test its telecommunication facilities needed to implement the restoration plan.

R6. Each Transmission Operator and Balancing Authority shall train its operating personnel in the implementation of the restoration plan. Such training shall include simulated exercises, if practicable.

R7. Each Transmission Operator and Balancing Authority shall verify the restoration procedure by actual testing or by simulation.

~~R8.~~Each Transmission Operator shall verify that the number, size, availability, and location of system blackstart generating units are sufficient to meet Regional Reliability Organization restoration plan requirements for the Transmission Operator's area.

~~R9.~~R8. ~~The Transmission Operator shall demonstrate, through simulation or testing, that its blackstart generating unit(s) can perform the startup functions as stated in the Transmission Operator's restoration plan. The Transmission Operator shall perform such simulation or testing at least every five years, and shall provide documentation to the Regional Reliability Organization on request.~~

~~R10.~~R9. The Transmission Operator shall document the ~~cranking path~~Cranking Paths or maintain ~~cranking path~~Cranking Path diagrams, including initial switching requirements, ~~associated~~ between each blackstart generating unit and the unit(s) to be started~~cranked~~ and shall provide documentation to the Regional Reliability Organization upon request.

~~R11.~~R10. Following a ~~disturbance~~Disturbance in which one or more areas of the Bulk Electric System (BES) become isolated or blacked out, the affected Transmission Operators and Balancing Authorities shall begin immediately to return the ~~Bulk Electric System~~BES to normal.

~~R11.1.~~R10.1. The affected Transmission Operators and Balancing Authorities shall work in conjunction with their Reliability Coordinator(s) to determine the extent and condition of the isolated area(s).

~~R11.2.~~R10.2. The affected Transmission Operators and Balancing Authorities shall take the necessary actions to restore ~~Bulk Electric System~~BES frequency to normal, including adjusting generation, placing additional generators online, or load shedding.

~~R11.3.~~R10.3. The affected Balancing Authorities, working with their Reliability Coordinator(s), shall immediately review the Interchange Schedules between those Balancing Authority Areas or fragments of those Balancing Authority Areas within the separated area and make adjustments as needed to facilitate the restoration. The affected Balancing Authorities shall make all attempts to maintain the adjusted Interchange Schedules, whether generation control is manual or automatic.

~~R11.4.~~R10.4. The affected Transmission Operators shall give high priority to restoration of off-site power to nuclear stations.

~~R11.5.~~R10.5. The affected Transmission Operators may resynchronize the isolated area(s) with the surrounding area(s) when the following conditions are met:

~~R11.5.1.~~R10.5.1. Voltage, frequency, and phase angle permit.

~~R11.5.2.~~R10.5.2. The size of the area being reconnected and the capacity of the transmission lines effecting the reconnection and the number of synchronizing points across the system are considered.

~~R11.5.3.~~Reliability Coordinator(s) and adjacent areas are notified and Reliability Coordinator approval is given.

R10.5.3.

~~R11.5.4.~~R10.5.4. Load is shed in neighboring areas, if required, to permit successful interconnected system restoration.

C. Measures

M1. The Transmission Operator shall , within 30 calendar days of a request, provide its Regional Reliability Organization with documentation of simulations or tests that demonstrate the resources (including ~~cranking path~~Cranking Paths) identified in the Transmission Operator's restoration plan are sufficient to support the Transmission Operator's restoration plan.~~The Transmission Operator shall, within 30 calendar days of a request, provide its Regional Reliability Organization with documentation of simulations or tests that demonstrate the blackstart units in its area are able to perform the functions of the restoration plan~~.

M2. The Transmission Operator shall, within 30 calendar days of a request from its Regional Reliability Organization, ~~provide~~ make available documentation or a diagram showing the number, size and location of system blackstart generating units and the associated ~~cranking path~~Cranking Paths for review at the Transmission Operator's locations.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

The Transmission Operator must have its plan to reestablish its electric system available for review by the Regional Reliability Organization at all times.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Transmission Operator shall demonstrate compliance through self-~~-~~certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: Plan exists but has not been reviewed annually.

2.2. **Level 2:** Plan exists but does not address one of the ~~r~~Requirements~~elements~~ listed in ~~Attachment 1-EOP-005~~EOP-005 R1.1 to R1.9.

2.3. **Level 3:** Not Applicable~~The Transmission Operator did not provide documentation or a diagram showing the number, size and location of system blackstart generating units and the associated cranking paths.~~

2.4. **Level 4:** There shall be a level four non-compliance if any of the following conditions exist:

2.4.1 Plan exists but does not address two or more of the ~~requirements~~ Requirements in EOP-005~~-1~~ R1.1 to R1.9.~~Attachment 1-EOP-005~~, ~~or~~

~~t~~There is no restoration plan in place~~,~~. ~~or~~

2.4.2

~~2.4.2~~2.4.3 ~~The Transmission Operator's s~~Simulation or test results demonstrating that ~~its~~the restoration plan ~~blackstart generating units~~can perform its ~~can perform their~~ intended function~~s~~ wasere~~ere~~ not provided, or the results were not compliant with the regional restoration plan,~~.~~ ~~or~~

2.4.4 ~~The Transmission Operator d~~Did not make available documentation ~~or a diagram~~ showing the number, size and location of system blackstart generating units and the associated ~~cranking path~~Cranking Paths.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

Members	Reliability Need?	Acceptable Translation?	Comments
Dan Griffiths – PA Office of Consumer Advocate	Yes	Yes	I believe that the language in the Purpose section is insufficiently precise. I suggest that the first sentence be modified to read: "To ensure that accurate, actual demand data is available and to support assessments and validation of past events and databases."
Response: Adopted revision to clarify purpose statement.			
Mohan Kondragunta – Southern California Edison WECC Reliability Subcommittee	Yes Yes	No No	SCE agrees with the data reporting requirements, but has a concern with the LSE as the responsible entity. Within the WECC region, control areas are currently the reporting entity. Prior to legislation, perhaps a backstop should be created wherein the balancing authority (BA) is responsible for providing data for LSEs within their area if the LSE is not providing the data.
Response: Functional model designates LSE as responsible for developing and reporting load forecast data. Regions and balancing authorities may have procedures or agreements that delegate the task to others, but ultimately the LSE has the information and the responsibility.			
Kansas City Power and Light	Yes	No	It appears the drafting team has chosen to rewrite this proposed standard and add new requirements. The Planning Authority should not be deleted from this standard.
Response: This standard addresses a regional procedure for forecasting and reporting demand data. The procedures need to be consistent across a wide area, such as a region, to ensure the data is consistent and valid for planning and reliability assessments. The related standards in Version 0 assign similar tasks to the RRO. There is still uncertainty in the functional model whether the Planning Authority is a wide-area function or can be a local entity.			

Ronnie Frizzell - Arkansas Electric Coop. Corp.	Yes	No	I oppose deleting the Planning Authority from this standard. There are cases where the RRO is not the Planning Authority and vice versa. This standard is to require the data for modeling purposes. The RRO is not necessarily the one building the models. Instead of a translation of the IID.M2 it looks like the drafting team decided to completely rewrite MOD-16. The translation goes way beyond the requirement to ensure no data is omitted or counted multiple times. The measures should be swapped. M2 measures R1 and M1 measures R2. Renumber M1 to M2 and M2 to M1 and reorder them. I disagree with the comment that it is not necessary to state requirements in other standards. This is done for reference to ensure that the requirements of one standard that apply to portions of another standard are acurrate and not over looked by the party responsible for compliance. Therefore I disagree with the deletion in R2 D 1.1.1 compliance monitoring should include the RRO for monitoring the PA.
Response: This standard addresses a regional procedure for forecasting and reporting demand data. The procedures need to be consistent across a wide area, such as a region, to ensure the data is consistent and valid for planning and reliability assessments. The related standards in Version 0 assign similar tasks to the RRO. There is still uncertainty in the functional model whether the Planning Authority is a wide-area function or can be a local entity. The cross reference was returned to the standard as suggested. The measures will be renumbered.			
FRCC	Yes	No	Agree that the amount of controllable DSM load should be reported (R4) but there should not be a requirement to report the location of customer load. The amount of controllable load is needed to determine the level of adequacy of Resources. Collecting the location of controllable load would be used only in situations where deliverability of resources is a concern. If there is a requirement to report

			the location of controllable customer load, it should only be a requirement on an aggregated basis over a geographic region when there are deliverability concerns. Requiring that entities report the location of all controllable customer load is burdensome and not worthwhile. **R6 should be changed to "Each Regional Reliability Organization shall use" (delete "A requirement that" at the beginning of R6), since the RRO should not develop a procedure requiring itself to something.** **M1 should be in Section C. (Measures) and the requirements at the end of the measure should be R2 to R5, not R1 to R6.** **Compliance section should be Section D and the requirements in Level 2 and 4 of non-compliance should both be R2 - R5 (not R1 only).**
Response: This comment recommends changes to an approved V0 standard. Only R1.2 has been introduced for the Phase III-IV planning standards scope. **Electrical location is necessary for modeling purposes.** **Formatting and numbering errors were corrected.**			
Individual Members of CCMC **Joseph D Williamson – PJM**	**Yes** **No**	**No** **No**	**R2-R7 should be sub-bullets of R1.** **Can't tell if compliance is to be measured against R1 or R1 through R7. It appears that the "clean version" file is different from the mapping file.** **Standard is missing section C heading for Measures. It appears that the "clean version" file is different from the mapping file.** **Measure 1 adds a requirement not contained in the Requirements for this standard. This should be in requirements..**

Response: Formatting and numbering errors were corrected.			
Consolodated Edison Cinod Kotecha IESO – Ontario Alan Adamson – NYSRC Kathleen Goodman – ISO-NE NPCC CP9 RSWG	Yes Yes Yes Yes Yes Yes	No No No No No No	R1.5 the use of the actual and forecast data as directly provided by the LSE must be analyzed to ensure it is properly aggregated to reflect coincident peak demands for system modeling and reliability analyses. It is suggested that the word "incorporate" be used instead of "use" in that Requirement. Also there is a formatting error in this Standard. M1 as it appears in the Requirements Section needs revision. R1 should be the Section and R2-R8 should be "sub" requirements due to the language at the end of R1.
Response: R1.5 is already approved in V0 and is outside the scope of the current project. **Formatting and numbering errors were corrected.**			
Michael C. Calimano – NYISO	Yes	No	Please note the formatting correction in NPCC's comment
Response: Formatting and numbering errors were corrected.			
SPP Transmissio n Working Group	Yes	No	Under B (requirement) item M1 be removed it is not a requirement
Response: Formatting and numbering errors were corrected.			
Peter Burke – American Transmissio	Yes	No	The formatting of and the number of Requirements and Measures listed in the clean Draft1 standard document is inconsistent with the translation mapping document. The version in translation mapping document is more acceptable

n Co.			since it is a better translation. Agree with removing Planning Authority as applicable entity and making this standard applicable to RRO only. A.3 Suggest adding interruptible load. R1.3 Suggest adding available trip speed of DSM load and adding amounts, location, and available trip speed of interruptible load.
Response: Formatting and numbering errors were corrected. Controllable load is meant to include interruptible load. R1.3 is outside the scope of this standards project.			
John Harris - Load Forecasting Working Group	Yes	Yes	Deletion of standard II.D.M3 is acceptable because its requirements have been merged with MOD-016-0.
Response: Thank you for your comment.			
John Horakh – MACC	Yes	Yes	Ok to delete Planning Authority
Response: Thank you for your comment.			
Data Coordinatio n Working Group	Yes	Yes	DCWG agrees with merging II.D.M2 into MOD-016 for clarity and efficiency among the data requirements standards. Additional clarity and efficiency could be gained by merging some parts of the other existing, related standards (MOD-016 through 021). For example, MOD-019, MOD-020 and MOD-021 could be merged into MOD-016 through MOD-018 - interruptible and load control do not need to be separated from demand and energy. Arguably, MOD-020 could remain separate as it requires the

			reporting of interruptible and load control to operating entities while the balance of the MOD-016 through MOD-021 are planning entity related. DCWG also believes that changing the applicability of MOD-016 to RROs instead of RROs and PAs is appropriate, clarifies responsibilities and reduces the possibility of "double jeopardy" among these standards (an entity being found non-compliant on multiple standards because of a non-compliance on a single element of a standard).
Response: Thank you for your support and comments. Additional changes to the organization of the standards would be beyond the scope of the current project.			
Gerald Rheault – Manitoba Hydro	Yes	Yes	Heading "Measures" is missing. MOD-017-0 should be modified to better compliment the revised MOD-016-1. Purpose: What is meant by "databases can be formed"? Data Retention: Who is the auditor - first time mentioned in the standard.
Response: Formatting and numbering errors were corrected. **MOD-017 is beyond the scope of the current project.** **Purpose has been revised to a more active statement.** **Auditor replaced with compliance monitor.**			
Midwest Reliability Organization	Yes	Yes	The heading for the "Measures" Section is missing. It is necessary for the requirements in MOD-016-1 to be complimentary to the requirements in MOD-017-0 regarding applicability for Load Serving Entities. MOD-016-1 and MOD-017-0 need to coordinate to address this issue.
Response: Formatting and numbering errors were corrected.			

Changing MOD-017 is outside the scope of the current project.			
Ed Riley – California ISO **ISO/RTO Council Standards Review Committee**	**Yes** **Yes**	**Yes** **Yes**	**Also there is a formatting error in this Standard. M1 as it appears in the Requirements Section needs revision. R1 should be the Section and R2-R8 should be "sub" requirements due to the language at the end of R1** **In some ISO/RTO market regions there are third party aggregators of DSM products (i.e. curtailment service provicders) that are not LSEs. Thus the information requirements of R4, R5, and R7 would be met by non-LSE's.**
Response: Formatting and numbering errors were corrected. **Functional model designates LSE as responsible for developing and reporting load forecast data. Regions and balancing authorities may have procedures or agreements that delegate the task to others, but ultimately the LSE has the information and the responsibility.**			
Entergy **SERC EC Planning Standards Subcommittee (PSS)**	**Yes** **Yes**	**Yes** **Yes**	**Recommend that R5 be revised to read "A requirement that each Load-Serving Entity update its actual and forecast customer demand values at least once each year according to a schedule."**
Response: R5 is part of existing V0 standard and is outside the scope of the existing project.			
Mark Kuras – MAAC	**Yes**	**Yes**	**Remove items under Data Retention. First item is redundant with the standard. Second item is part of the auditing procedures of each region and don't need to be part of the standard. Remove text under Additional Compliance Information because it is up to the region how it will do complince and should not be part of the standard.**
Response: This is standard format being used across the standards.			
Raj Rana – AEP	**Yes**	**Yes**	**Format Fix required: Need "Measures" Heading. Requirements numbering in the draft standard does not**

			agree with comparison document. How do the last 2 requirements relate to the levels of non-compliance?
Response: Formatting and numbering errors were corrected.			
Tennessee Valley Authority	Yes	Yes	
Xcel Energy – Northern States Power	Yes	Yes	
Joseph F. Buch – Madison Gas and Electric	Yes	Yes	
Howard Rulf - WE Energies	Yes	Yes	
Karl A. Bryan - US Army Corps of Engineers	Yes	Yes	
Karl Kohlrus - City Water, Light & Power	Yes	Yes	
John K. Loftis, Jr. – Dominion –	Yes	Yes	

Electric Transmission			
Gred Mason – Dynergy Generation	Yes	Yes	

A. Introduction

1. Title: **Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management**

2. Number: MOD-016-~~0~~ 1

~~3.~~Purpose: ~~To e~~Ensure that accurate, actual Demand data is available to support assessments and validation of past events and databases. ~~can be performed, reporting of actual demand data is needed.~~ Forecast ~~demand~~ Demand data is needed to perform future system assessments to identify the need for system reinforcements for continued reliability. In addition, to assist in proper real-time operating, ~~load~~ Load information related to controllable Demand-Side Management (DSM) programs is needed.

3.

4. Applicability:

~~4.1.Planning Authority~~

~~4.2.~~4.1. Regional Reliability Organization

5. Proposed Effective Date: April 1, ~~2005~~2006

B. Requirements

R1. The ~~Planning Authority and~~ Regional Reliability Organization shall develop and maintain a procedure that identifies ~~have documentation identifying~~ the scope and details of the actual and forecast (a) Demand data, (b) Net Energy for Load data, and (c) controllable DSM data to be reported for system modeling and reliability analyses. The procedure shall include all of the following:

R1.1. The aggregated and dispersed data submittal requirements shall ensure that consistent data is supplied for Reliability Standards TPL-005-0, TPL-006-0, MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-0, MOD-014-0, MOD-015-0, MOD-016, MOD-017-0, MOD-018-0, MOD-019-0, MOD-020-0, and MOD-021-0.

R1.2. A requirement that each Load-Serving Entity develop a set of consistent actual and forecast customer demand values for consistent use in all its data reporting during a calendar year.

R1.3. A requirement that each Load-Serving Entity count each customer within its service territory once and only once in developing its actual and forecast customer demand values.

R1.4. A requirement that each Load-Serving Entity with a controllable DSM program identifies the amounts and locations of customer Load designed to be curtailed with that DSM program.

R1.5. A requirement that each Load-Serving Entity update its actual and forecast customer demand values once each year according to a schedule.

R1.6. A requirement that each Regional Reliability Organization use the actual and forecast data provided by the Load-Serving Entities in conducting its reliability assessments.

R1.7. A schedule for each Load-Serving Entity to provide its actual and forecast demand data and the amount of customer Load designed to be curtailed with a controllable DSM program to its Planning Authority and Regional Reliability Organization.

R2. The Regional Reliability Organization shall distribute its procedure for reporting customer Demand data to all Planning Authorities and Load-Serving Entities that work within its Region within 30 calendar days of approval. ~~documentation of the scope and details of the data reporting requirements shall be available on request (five business days).~~

C. Measures

M1. The Regional Reliability Organization's procedure for actual and forecast customer Demand data shall contain all items identified in R1.

~~M1.~~M2. The ~~Planning Authority and~~ Regional Reliability Organization shall ~~each provide~~have evidence ~~to its Compliance Monitor that~~ it provided its actual and forecast customer Demand data ~~and~~ reporting procedure~~s~~ within 30 calendar days of approval to each Planning Authority and Load-Serving Entity that works within its Regional Reliability Organization. ~~per Reliability Standard MOD-016-0_R1 and MOD-016-0_R2.~~

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

~~Compliance Monitor for Planning Authority: Regional Reliability Organization. Compliance Monitor for Regional Reliability Organization:~~ NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

~~1.3.~~One calendar year.

~~On request (five business days.)~~

1.3. Data Retention

For the Regional Reliability Organization: Current version of the procedure.

For the Compliance Monitor: Three years of audit information.

~~None specified.~~

1.4. Additional Compliance Information

The Regional Reliability Organization shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

~~None.~~

2. Levels of Non-Compliance

2.1. Level 1: ~~Identified the scope and details of demand, Net Energy for Load, and controllable DSM data to be reported and the reporting procedures but did not specify that consistent data is to be supplied for Reliability Standards TPL-005-0, TPL-006-0, MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-0, MOD-014-0, MOD-015-0, MOD-016, MOD-017-0, MOD-018-0, MOD-019-0, MOD-020-0, and MOD-021-0~~Not applicable.

2.2. Level 2: The procedure did not address one of the elements in R1~~Not applicable~~.

2.3. Level 3: Not applicable.

2.4. Level 4: Either the procedure did not address two or more of the required elements in Requirement R1 or there was no procedure~~Did not identify the scope and details of demand, Net Energy for Load, and controllable DSM data to be reported and the reporting procedures~~.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

<table>
<tr><th>Members</th><th>Reliability Need?</th><th>Acceptable Translation?</th><th>Comments</th></tr>
<tr><td>Entergy</td><td></td><td></td><td>(From Q 4 – Other comments)
The last sentence of R.4 "open circuit test … terminal voltage." appears to be the same as Requirement R.5 and should be deleted.</td></tr>
<tr><td colspan="4">Response: R4 addresses new or refurbished units and was revised to clarify that. The open circuit test in R5 was moved to R3 to more clearly show it is part of the verification results to be reported.</td></tr>
<tr><td>Gred Mason – Dynergy Generation</td><td></td><td></td><td>(From Q 4 – Other comments)
For Generation Owners,all of MOD-026-1 seems largely redundant to MOD-012-0.Suggest deleting Generation Owners from MOD-012-0.</td></tr>
<tr><td colspan="4">Response: MOD-012 addresses reporting of data and what types of data need to be reported. MOD-026 focuses more specifically on verification of excitation system and voltage control model data.</td></tr>
<tr><td>IESO</td><td></td><td></td><td>(From Q 4 – Other comments)
We suggest adding a requirement for Generator Owners to provide automatic to manual AVR tracking validation.
We suggest adding more tests to ensure the stabilizers are working properly (e.g. Step Tests)
We suggest replacing the term 'data' with 'models and data' in the sentence:
"The Generator Owner shall, within 30 calender days of a request, provide to the Regional Reliability Organization and applicable Transmission Planner(s) 'data' associated… "
R2 - We suggest replacing the term 'verify' with 'validate' in the sentence:
"The Generator Owner shall 'verify' the data used in…"
R3 - If any of the information outlined in this requirement is unavailable, we suggest obligating the Generator Owner to perform tests that are necessary to verify the model.</td></tr>
<tr><td colspan="4">Response: AVR tracking is addressed in the VAR standards (VAR-001 for the TOP and VAR-002 for the generator).
The drafting team has added test results to the power system stabilizer requirement. Details of testing requirements are to be established in the RRO procedure.</td></tr>
</table>

The model type can be identified from the information provided by the generator under R3.1 – type of equipment and manufacturer. The drafting team believes that verify is a better term than validate, and is consistent with language used in other standards. The requirement to verify data, whether or not the data is currently available, is defined in R2.			
PPL Corporation			(From Q 4 – Other comments) The Regional Reliability Organization needs to determine the frequency and overall criteria required for any generation testing in support of these new standards. The needs basis shall only evaluate units that have a significant affect on the safe and reliable operation of the transmission system. Any test that is required on generator equipment needs to be subject to a risk analysis where the value of the test is evaluated against the risk that such test would impact the generation equipment and transmission system. Only units or stations that have a significant affect on the system should be tested. Nuclear units should be exempted from on-line testing unless the Nuclear Generator Owner can demonstrate through the 10CFR50.59 screening process that such testing is not an Unreviewed Safety Question (USQ). PPL believes that real-time operational data could be used in lieu of on-line testing in some instances to validate the range of reactive capabilities.
Response: The drafting team agrees. The RRO was assigned responsibility for developing these procedures so that these procedures can reflect regional needs. The regional procedures are required to include generating unit exemption criteria including documentation of those units that are exempt from a portion or all of the procedures for verifying generation equipment data. The commenter is encouraged to offer assistance in developing the regional procedures. ~~The RRO has been assigned responsibility for this procedure because regional reliability needs and risk factors need to be considered by the procedure. The regional procedure should address nuclear plant testing exemptions that would be justified by nuclear safety regulations. The commenter is encouraged to participate in the development of the regional procedure.~~			
SPP Transmission Working Group			(From Q 4 – Other comments) MOD-023 thru 027 should include planning authorities.
Response: The Planning Authority was added as a recipient of the RRO's procedures in MOD-023 and the Planning Authority was added as a recipient of the Generator Owner's data in MOD-024 through MOD-027. ~~The drafting team has added planning authorities as requested.~~			
Pacific Gas and			Our facility is on a 20-22 month fuel cycle and should not be required to do testing

Electric			requiring taking the unit offline mid-cycle, for example, to do open circuit response tests.
Response: Frequency of verifications and any exemptions ~~for nuclear plants~~ are to be addressed in the RRO procedure ~~(MOD-023)~~. The commenter is encouraged to offer assistance in developing the regional procedures.~~The commenter is encouraged to participate in the regional process for developing that procedure. Risk and cost factors should be considered in development of the regional procedure.~~ The regional procedures are required to include generating unit exemption criteria including documentation of those units that are exempt from a portion or all of the procedures for verifying generation equipment data.			
Wing Joe- BC Hydro	No Answer	No	Model should align with the equipment, not the reverse. It is unreasonable to expect the Generator Owner to verify the data the transmission planner use in their model of the system. The only obligation that the Generator Owner should bear is to provide the necessary equipment info to the transmission planner, who then includes that equipment in his/her system studies.
Response: The purpose statement has been revised to make this clarification.			
Greg Ludwicki – Northern Indiana Public Service Co.	Yes	No	I interpret requirement for an annual open circuit response test. Recommend a longer time frame unless operational anomalies are encountered.
Response: Frequency of verifications is to be addressed in the RRO's procedure ~~(MOD-023)~~. The commenter is encouraged to offer assistance in developing the regional procedure. ~~The commenter is encouraged to participate in the regional process for developing that procedure. Risk and cost factors should be considered in development of the regional procedure.~~			
Joseph F. Buch – Madison Gas and Electric	Yes	No	The standard requires verification of the data but does not spell out what the data is or how it is to be verified. It also requires open circuit test response chart recordings but does not spell out who's responsible for developing the test. In addition it requires excitation system model data and verification without indicating the type of model. It is recommended that this standard undergo field testing to better define the requirements. At the same time the need to provide data on small units (<50 MW) or those with manual operation should be evaluated. Units on manual operation, or small units likely provide little if any benefit and the cost of testing needs to be justified.
Response: Verification methods are to be determined in the RRO's procedure. The commenter is encouraged to offer assistance in developing the regional procedures.~~The commenter is encouraged to participate in the regional process for developing that procedure. Risk and cost factors should be considered in development of the regional procedure.~~ The drafting team is recommending that this standard be field tested before it is finalized.			

The RRO's procedure must identify generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures. ~~proposing a phased approached to implementing this standard, to allow entities to achieve compliance.~~			
Carol L. Krysevig – Allegheny Energy Supply Co.	Yes	No	MOD-026-1 as written places the burden on the Generator Owner to verify data used in dynamic models for excitation systems while not having any expertise in system studies, model derivation and use. This standard, and specifically requirements R2, R3 and R5 would result in a Generator being required to furnish, within thirty days, excitation data on 20, 30.. or more units with accompanying field testing that may be required, all without missing any elements. I question how many deregulated utilities can meet that standard. While I do agree that a program is needed to ease into a joint database of excitation parameters between System Planners and Generator Owners this standard goes beyond full cooperation.
Response: The RRO procedure will address the requirements and timing of required data. The commenter is encouraged to offer assistance in developing the regional procedures.~~The drafting team encourages the commenter to participate in the regional process to develop those requirements and reporting schedule.~~ The drafting team is proposing that this standard be field tested before it is finalized.			
Mark Kuras – MAAC	Yes	No	The main issue remains whether or not to require testing of generating unit excitation systems. The term …verify… is too vague and seems to invite either confusion or continuation of the status quo. The listing under R3 is a hodge-podge of qualitative and numerical responses. The list neither requires that the excitation system model conform to IEEE Standard 421.5, nor that simulation code to implement non-conforming models be provided and documented. If no IEEE standard or PSSE or PSLF/PSDS standard library model adequately represents excitation system response, the generator owner should be required to have a user-defined model written and validated and provide documentation to the user community. In many cases generator owners may not have expertise to conduct any independent review of vendor data, particularly to determine whether any device settings have changed sufficiently to affect vendor estimates of model parameters but this does not relieve them of the responsibility to provide an adequate simulation model. A periodic review or retesting interval should be specified for parameters affected by field adjustable settings. Change Data Retention text to require that the Generator Owner shall retain

			commissioning and test reports and data as long as either (1) the equipment is in service or (2) events in which its response was significant remain under investigation. Delete text under Additional Compliance Information because it is up to the region as to how compliance will be measured. This text adds nothing to the standard.
Response: An open circuit test is required i~~n R3.6 (as revised~~n the revised standard~~)~~. The drafting team believes and is supported by industry comment, that alternative methods for verification of data can also be valid. The applicable methods are to be identified in the RRO's procedure .~~per MOD-023.~~ ~~The commenter is encouraged to participate in the regional process for developing that procedure.~~ ~~Risk and cost factors should be considered in development of the regional procedure.~~ The suggested requirements to improve consistency of the quantitative data reported, including use of IEEE standards can be incorporated into the RRO procedure. The drafting team does not believe there is sufficient consensus on these requirements for reporting of quantitative data to include in a NERC standard at this time. The generator owner retains responsibility for accurate generator data, even if the generator ~~operator~~ owner does not have the expertise in house. Frequency of verifications is to be addressed in the RRO's procedure. ~~(MOD-023).~~ The commenter is encouraged to offer assistance in developing the regional procedures.~~The commenter is encouraged to participate in the regional process for developing that procedure. Risk and cost factors should be considered in development of the regional procedure.~~ The data retention requirement has been revised to be consistent with other standards. ~~Additional compliance language is consistent across the standards being proposed.~~ The compliance information identifies how compliance with NERC standards will be determined. If the compliance information indicates that compliance will be measured through annual self-certification, then that is how the Compliance Monitor must measure compliance with this standard. It is not completely up to the Region to determine how to measure compliance with NERC Standards.			
~~Multi-Regional Modeling Working Group~~	Yes	No	The main issue remains whether or not to require testing of generating unit excitation systems. The term …verify… is too vague and seems to invite either confusion or continuation of the status quo. Some units need to be tested and others don't. An example of a determining factor for testing is whether a unit is stability constrained or its participation in poorly damped power swings. The listing under R3 is a hodge-podge of qualitative and numerical responses. The list neither requires that the excitation system model conform to IEEE Standard 421.5, nor that simulation code to implement non-conforming models be provided and documented. If no

			IEEE standard or PSSE or PSLF/PSDS standard library model adequately represents excitation system response, the generator owner should be required to have a user-defined model written and validated and provide documentation to the user community. The generator owner must be required to demonstrate that the model and parameters provided under R3 will simulate a response corresponding to the test charts of R4 or R5. In many cases generator owners may not have expertise to conduct any independent review of vendor data, particularly to determine whether any device settings have changed sufficiently to affect vendor estimates of model parameters but this does not relieve them of the responsibility to provide an adequate simulation model. A periodic review or retesting interval should be specified for parameters affected by field adjustable settings. Change Data Retention text to require that the Generator Owner shall retain commissioning and test reports and data as long as either (1) the equipment is in service or (2) events in which its response was significant remain under investigation. Delete text under Additional Compliance Information because it is up to the region as to how compliance will be measured. This text adds nothing to the standard.

Response: An open circuit test is required in ~~R3.6 (as revised)~~the revised standard. The drafting team believes and is supported by industry comment, that alternative methods for verification of data can also be valid. The applicable methods are to be identified in the RRO's procedure. ~~per MOD-023. The commenter is encouraged to participate in the regional process for developing that procedure. Risk and cost factors should be considered in development of the regional procedure.~~

The suggested requirements to improve consistency of the quantitative data reported, including use of IEEE standards can be incorporated into the RRO procedure. The drafting team does not believe there is sufficient consensus on these requirements for reporting of quantitative data to include in a NERC standard at this time.

The generator owner retains responsibility for accurate generator data, even if the generator ~~operator~~ owner does not have the expertise in house.

Frequency of verifications is to be addressed in the RRO's procedure. ~~(MOD-023).~~ The commenter is encouraged to offer assistance in developing the regional procedures.~~The commenter is encouraged to participate in the regional process for developing that procedure. Risk and cost factors should be considered in development of the regional procedure.~~

The data retention requirement has been revised to be consistent with other standards.

The compliance information identifies how compliance with NERC standards will be determined. If the compliance information indicates that compliance will be measured through annual self-certification, then that is how the Compliance Monitor must

measure compliance with this standard. It is not completely up to the Region to determine how to measure compliance with NERC Standards. ~~Additional compliance language is consistent across the standards being proposed.~~			
Tennessee Valley Authority	Yes	No	If a model does not conform to an IEREE standard or PSSE or PSLF/PSDS standard library model, the generator owner should be required to have a user-defined model written and validated. Test reports should always be provided to the transmission planner along with the model so independent checking so generator verification is possible. There should be a MW cutoff – exemption that is allowed if approved by the Transmission Provider.
Response: The suggested requirements to improve consistency of the quantitative data reported, including use of IEEE standards can be incorporated into the RRO procedure. The drafting team does not believe there is sufficient consensus on these requirements for reporting of quantitative data to include in a NERC standard at this time. The standard as drafted requires the data to be provided to the transmission planner. Exemptions are to be identified in the RRO's procedure.~~, per MOD-023.~~ The commenter is encouraged to offer assistance in developing the regional procedures.~~The commenter is encouraged to participate in the regional process for developing that procedure.~~			
Cinod Kotecha	Yes	Yes and No	Although in concept collecting this information has value, the actual testing required to validate the parameters could be a detriment to reliability. NERC needs to consult with those who perform dynamic analysis and seek their input and weigh it appropriately.
Response: The RRO was assigned responsibility for developing these procedures so that these procedures can reflect regional needs.~~Risk and cost factors should be considered in development of the regional procedure.~~ The commenter is encouraged to offer assistance in developing the regional procedures.			
Constellation Generation Group	Yes	No	Requirements need to be more specific. What method of verfication is acceptable? There is not standard test out there.
Response: The applicable methods are to be identified in the RRO's procedure.~~, per MOD-023.~~ ~~T~~ The commenter is encouraged to offer assistance in developing the regional procedures.~~he commenter is encouraged to participate in the regional process for developing that procedure.~~			
SPP Transmission Working Group	Yes	No	Title should read VERIFICATION OF GENERATOR EXCITATION SYSTEM AND VOLTAGE CONTROL MODELS. Purpose should be changed to the first sentence of the old standard. R1 & R3 should include the Planning Authority. Refer to Funtional Model, Planing Authority, 1c.

Response: The title has been revised. The purpose has been clarified. Planning authority has been added as a recipient of the RRO's procedures and as a recipient of the GO's data.			
Ronnie Frizzell - Arkansas Electric Coop. Corp.	Yes	No	R3 should include the Planning Authority. Refer to Functional Model, Planning Authority, 1C.
Response: Planning authority has been added as a recipient of the RRO's procedures and as a recipient of the GO's data.			
Kansas City Power and Light	Yes	No	It appears that these requirements are addressed in standards MOD-010 through MOD-013. R1 and R3 should include the Planning Authority
Response: MOD-010 to 013 address reporting of data and what types of data need to be reported. MOD-026 focuses more specifically on verification of excitation systems and voltage control models. Planning authority has been added as a recipient of the RRO's procedures and as a recipient of the GO's data~~.~~			
Gred Mason – Dynergy Generation	Yes	No	1. NERC should not eliminate specifying a minimum verification frequency(every 5 years in the current standard).NERC should provide this guidance to the Regions. Regions can always be more stringent when regional needs require more frequent verification. Therefore,suggest adding "every five years" verification requirement in Sections B,R1, B,R2, B,R3 and C,M1. 2. Analogous to comment #1 above, Section B,R4 should include the one year requirement that in Section M6 of the curent standard. 3. Section B,R5 appears to be a new requirement relative to the current standard and should be deleted.Also,the same wording in Section B,R4 seems to cover the intent of the current standard.
Response: Frequency of verifications is to be addressed in the RRO's procedure ~~(MOD-023)~~. ~~T~~The commenter is encouraged to offer assistance in developing the regional procedures.~~he commenter is encouraged to participate in the regional process for developing that procedure. Risk and cost factors should be considered in development of the regional procedure.~~			

R5 was deleted (a portion was moved to R1.4~~3~~.6).			
FRCC	Yes	No	The requirements for the proposed standard should be limited to R1 only. Delete R2 - R5. MOD-23 gives the RRO the responsibility to identify the required testing and the verification requirements. While it is important to have accurate excitation system models, the reliability improvement gained does not always justify the manpower requirements to test and verify the inteconnected synchronous generators. If R2 - R-5 remain requirements for this standard, we do not support this as a standard.
Response: The drafting team subdivided MOD-023 and distributed the RRO's requirement to develop procedures directly into MOD-024 through MOD-027. Revised MOD-026 contains the RRO's requirement to develop a procedure for data verification, along with the Generator Owner's requirement to verify and report that data. The revised MOD-027 reflects deletion of most of R5. R1~~ has been~~ merged with R3 and R5 has been removed. (In the revised standard, the combined requirements are contained in R3.) The new R~~2 (old R3)~~1 identifies minimum requirements that need to be addressed in the regional procedure. The standard allows the region significant latitude in establishing what verification methods are acceptable within the region to verify this data. ~~The drafting team is proposing a phased implementation to allow compliance and the region may within its procedure provide a phased schedule for provision of the data.~~The drafting team is recommending that this standard be field tested before it is finalized.			
Rebecca Berdahll – Bonneville Power Administration Karl Bryan – Corp of Engineers Jay Sietz – US Bureau of Reclamation Brenda Anderson Deborah M. Linke – US Bureau of Reclamation	Yes Yes	No No	R3.3 requires model and data verification of over and under excitation limiters. IEEE is still working to develop a model for limiters after which the dynamic simulation software vendors will incorporate the models into their programs. We recommend striking verification of limiter models until models approved by the RRO are available. We also recommend as a practical matter that a phase-in period be provided by the RRO. This will allow entities with a large number of machines to distribute the validation and re-validation process over a period of time (3-5 years).
Response: The language has been revised to "Static set points for" under and over ….			

The drafting team is recommending that this standard be field tested before it is finalized.~~proposing a phased implementation of the standard and each region may further designate an appropriate schedule for verification and reporting of data within the region.~~			
Kenneth Dresner – FirstEnergy Solutions	Yes	No	Section R2 - 1. The word 'verify' needs additional clairification, such as, ". . . Owner shall verify by test, configuration control reviews or other means the data used in dynamic models . . ." These two standards should be kept separate to help facilitate tracking compliance at the physical level and help focus on the areas of non-compliance MOD-023-1 calls out a separate requirement for each of the proposed merged standards The ablity to identify the need for a change in excitation system a year in advance is not always pratical and therefore the need to submit information a year in advance should be dropped or modified accordingly
Response: The applicable verification methods are to be identified in the RRO's procedure.~~ per MOD-023.~~ The commenter is encouraged to offer assistance in developing the regional procedures.~~The commenter is encouraged to participate in the regional process for developing that procedure.~~ The drafting team disagrees because the prior measures refer to related information. There is no requirement to submit the information a year in advance.			
Trilok C. Garg – Mirant Mid Atlantic	Yes	No	Paragraph BR1 - Not clear, what information can be provided for ,'limiters, compensators". suggest to remove the wordings - limiters, compensators.
Response: Limiters has been clarified by adding 'static'. The data needed is whether there is a compensator or not, the type and quantitative data to characterize the anticipated performance of the device.			

NERC Interconnection Dynamics Working Group	Yes	No	Title should be changed to: Verification of Generator Excitation Systems and Voltage Control Models — Purpose should be modified to: To verify generator excitation system models and parameters (including voltage regulator controls, limiters, compensators, and power system stabilizers, if applicable) used to assess Bulk Electric System reliability. — R1 – The Generator Owner shall…and applicable Transmission Planner(s) modeling data associated with…Organization requirements. The data shall be compatible with the standard excitation system models available in stability programs widely used in the industry. If a new model is necessary for reasonable representation of the equipment, the new model must be developed for industry-wide use. — R2:…shall verify the data used in models … In the absence of generator model validation standards; this will be difficult to enforce. — R1 – This data submittal aspect is already addressed in MOD-012-0 and MOD-013-0 (both have typo/format errors). Such duplicate inconsistent requirements need to be avoided in Industry STANDARDS. — R3, R4 and R5: …as required by the RRO procedures… imply that these need to be addressed by the RRO procedures. But MOD-023-1 does not require RRO procedures to address those things. — Add R6: Any field changes made by the Generation Owner or Generator Operator to the verified data described in R1 above shall be re-verified / tested as soon as possible. Such changes, and their associated verification/testing results, shall be coordinated with the Transmission Owner, Planning Authority, and Transmission Planners, and reported to the region within 30 days.
Response: The title and purpose have been revised for clarification. R1 has been deleted in deference to what was R3 ~~(now R2)~~. (NEED RESPONSE TO COMMENT ON R2) The drafting team subdivided MOD-023 and distributed the RRO's requirement to develop procedures directly into MOD-024 through MOD-027. Revised MOD-026 contains the RRO's requirement to develop a procedure for data verification, along with the Generator Owner's requirement to verify and report that data, eliminating the inconsistencies noted between R3, R4, and R5 with MOD-023. ~~The suggested requirements to improve consistency of the quantitative models, including use of IEEE models, can be incorporated into the~~			

~~RRO procedure. The drafting team does not believe there is sufficient consensus to define standardized models within a NERC standard at this time. Standardized models were not defined in the prior planning standards and are therefore not within the scope of the SARs to translate the prior planning standards not included within Version 0. The drafting team suggests the IDWG submit a SAR to propose standardizing exciter models used for reliability analysis.~~ ~~MOD-012-013 address reporting of data and what types of data need to be reported. MOD-026 focuses more specifically on verification of excitation system data.~~ ~~MOD-023 and MOD-026 have been linked by reference.~~ The requirement to update verification data/results if the excitation system is refurbished is already ~~provided (now in R3).~~in the standard.			
Southern Company Generation	Yes	No	SDT should incorporate the levels of non-compliance for this standard as recommended for MOD-024. R1 & R3 - The 30 day reporting requirement is too demanding, especially if a large number of units are involved. R5 should allow for alternatives to the open-circuit step response test. This new standard will require extensive operation effort, engineering analysis, and field testing to accomplish. Furthermore, it is impractical for a Utility with many large generating units to accomplish full compliance in a short time period. While we agree fundamentally there is a reliability need for this standard, the reliability importance and impact of all generators on the system is not the same. A phased approach that prioritizes the implementation for existing generators would provide reliability benefits and help reduce the strain on industry resources. We recommend this approach be reflected under the Compliance section, allowing an initial seven calendar year phase-in period, then one calendar year. The accomplishment of this should be coordinated with Standards MOD-025 and PRC-019.
Response: The objective is to have verified data from each generator that is required to provide data, whether an entity has one generator or many. Compliance violations should be reported so as to not unfairly characterize the extent of the violation. The RRO's procedure must identify generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures. 30 days refers to the time administratively to respond to a request, not to perform data verifications. It is anticipated that the data will be available already, per the ~~implementation~~ reporting schedule outlined in the RRO's procedure. The RRO's procedure may define alternative verification methods. The commenter is encouraged to offer assistance in developing the regional			

procedures. ~~The commenter is encouraged to participate in the development of that procedure.~~ The drafting team is ~~proposing a phased approach and it is anticipated that the RRO procedures will provide a schedule for implementation within the region.~~recommending that this standard be field tested before it is finalized. The implementation of this standard ~~will be coordinated with the other standards referenced.~~does not rely on any other standard.			
Southern Company – Transmission	Yes	No	Requirements R3.1, R3.2, R3.3, R3.4, R3.5, R3.6, R3.7 belong in MOD-023. These are details that should be specified in the Regional requirements. R3 should say -The Generator Owner shall, within 30 calendar days of a request, provide to the Regional Reliability Organization and applicable Transmission Planner(s) the results of excitation system model and data verification, including the information as required by the Regional procedures.- Same comments as on MOD-025, including levels of non compliance and the 2 - 3 year time period before being held to compliance requirements. R1 & R3 - The 30 day reporting requirement is too demanding, especially if a large number of units are involved. It is impractical for a Utility with many large generating units to accomplish in a short time period. R2 - We recommend that you add a note that says changes in AVR, PSS and other controls should be communicated, in real time, to TOP. In R3 – The model supplied has to be usable. There is a practice by certain manufacturers of supplying an unknown model which does not fit into any known stability program. The generator owner should be required to supply data that is applicable for known models that have been approved and are commonly available, e.g. IEEE models. If the model is a new, standard models must be developed and established for industry-wide use. Further, proprietary dynamic models for existing generators shall be converted to standard models or new models must be developed and established for industry-wide use
Response: -The drafting team subdivided MOD-023 and distributed the RRO's requirement to develop procedures directly into MOD-024 through MOD-027. Revised MOD-026 contains the RRO's requirement to develop a procedure for data verification,			

along with the Generator Owner's requirement to verify and report that data. ~~MOD-023 and MOD-026 have been linked by reference.~~ R3 was reworded as requested~~ and is now numbered R2~~. The objective is to have verified data from each generator that is required to provide data, whether an entity has one generator or many. Compliance violations should be reported so as to not unfairly characterize the extent of the violation. The regional procedures are required to include generating unit exemption criteria including documentation of those units that are exempt from a portion or all of the procedures for verifying generation equipment data. ~~Data retention requirement has been corrected in compliance section.~~ 30 days refers to the time administratively to respond to a request, not to perform data verifications. It is anticipated that the data will be available already, per the ~~implementation~~ reporting schedule outlined in the RRO's procedure. Reporting of real-time status of AVR and PSS is addressed in separate standards. The suggested requirements to improve consistency of the quantitative models, including use of IEEE models, can be incorporated into the RRO procedure. The drafting team does not believe there is sufficient consensus to define standardized models within a NERC standard at this time. ~~Standardized models were not defined in the prior planning standards and are therefore not within the scope of the SARs to translate the prior planning standards not included within Version 0.~~			
SPP Generation Working Group	Yes	No	R2: To obtain this data the generator will need to inject/absorb the maximum amount of VAR it can produce at various MW level. Hence you have similar operating problems and coordination problems as discussed in MOD-025. R5: This test requires the unit to be off line. Some units are scheduled to be on line over 18 months prior to an overhaul. Taking the unit off line, strictly for testing, could be very costly due to the replacement energy cost might be natural gas base as opposed to a coal base. Hence the time between tests must to be longer then one year. Compliance: Similar testing concerns to as discussed in MOD-025. This testing will require sophisticated monitoring equipment. A concern exists that if the entire country adopts this standard there will not be enough equipment nor manpower to get it done in such a short period. Taking the unit off line, strictly for testing, could be very costly due to the replacement cost of energy might be natural gas as opposed to coal that the unit to be tested is burning. Hence the time between tests must to be longer then one year. If a company has similar units, we would propose that one unit be tested and those characteristics would be applied to other similar units in the company's fleet, similar to WECC's testing procedure.

			GWG believes a minimum of a five year testing cycle is more appropriate o If a company has similar units, we would propose that one unit be tested and those characteristics would be applied to other similar units in the company's fleet, similar to WECC's testing procedure. o OG&E believes a minimum of a five year testing cycle is more appropriate.
Response: The drafting team does not believe the draft standard requires a max leading/lagging injection of reactive. The applicable verification methods are to be identified in the RRO's procedure. ~~per MOD-023.~~ The commenter is encouraged to offer assistance in developing the regional procedures.~~The commenter is encouraged to participate in the regional process for developing that procedure. Risk and cost factors should be considered in development of the regional procedure.~~ Exemptions and timing of testing are to be addressed in the regional procedure. The drafting team is recommending ~~a phased implementation to allow compliance to be achieved. The regional plan will also address timing requirements for the reporting of the data.~~that this standard be field tested before it is finalized.			
Joseph D Williamson – PJM	No	No	Level 1 is difficult to measure and may be going beyond the stated requirements. Level 3 should only reference R4 R1 Remove the "within 30 days of a request" here and in every requirement that it shows up. Data, documentation, etc should be available whenever requested. M1 seems to go beyond the stated requirement.
Response: References to requirement numbers have been corrected. 30 days is the administrative time to gather and submit the data following a request. It is expected the verification data would be developed and available per the RRO procedure. M1 has been merged into M2 ~~(new M1)~~.			
Individual Members of CCMC	Yes	No	Level 1 is difficult to measure and may be going beyond the stated requirements. Compliance is a function of finding the appropriate Regional documents and basically doing a Regional compliance check – more a Regional compliance program. Level 3 needs to be rewritten to include R4 which appears appropriate for inclusion. R1 Remove the "within 30 days of a request" here and in every requirement that it shows up. Data, documentation, etc should be available whenever requested. This makes short notice audits difficult and does not allow for checking that things are done in real time,

			such as checking that documents are readily accessible to operators. M1 seems to go beyond the stated requirement.
Response: Compliance levels were revised. 30 days is the administrative time to gather and submit the data following a request. It is expected the verification data would be developed and available per the RRO procedure. M1 has been merged into M2~~ (new M1)~~.			
Kathleen Goodman – ISO-NE	Yes	Yes	Although in concept that collecting this information has value, the actual testing required to validate the parameters could be a detriment to reliability. The development of this standard need more technical development.
Response: The tests are offline and are not an immediate threat to system reliability.			
Barry Green – Ontario Power Generation	Yes		There is some inconsistency in this package of standards affecting generators, between applicability to generator owner in some cases and generator operator in others. For this standard, MOD-026-1, the applicability must lie with the generator operator. In many cases, the owner, by virtue of contractual obligations, would not have the ability to carry out the obligations imposed by this standard. In other cases, ownership could be shared and it would not be appropriate for these obligations to be shared. Therefore, the applicability of this standard more correctly belongs with the generation operator. Alternatively, if NERC chooses to be less prescriptive, it could, for the purposes of the standard, place an obligation on the owner or operator, with an obligation on the region to clarify in each case, the appropriate entity to meet the requirements.
Response: The functional model assigns capability verification to the generator owner. The comment could be an issue when there are joint owners, but in these cases there are agreements to address delegation of this task among the owners.			
WECC Reliability Subcommittee Mohan Kondragunta – Southern California Edison	Yes Yes	Yes Yes	WECC RS agrees with the removal of the five-year testing requirement and that it should be established by the RRO.
Response: Thank you for the comment.			

John Horakh – MACC	Yes	Yes	Good conversion from prescribed testing to verification. However the Generator Owner may require significant time beyond November 1, 2005 for the initial verification. An effective date of five years beyond Board approval is more realistic.
Response: Thank you for the comment. ~~The drafting team is proposing a phased implementation. The RRO procedure will also include a schedule for implementation within the region.~~The drafting team is recommending that this standard be field tested before being finalized.			
Samuel W. Leach – TXU Power	Yes	Yes	The overall excitation system respponse values can be tested and verified. However it can be very difficult and sometimes imporactical to verify individual regulator and PSS subsystem components. Manufacturer desgin constants should be accepted where verification testing is impractical.
Response: The drafting team believes the open circuit step response test will verify the overall excitation system response, including the voltage regulator response. PSS should be included in the test. These tests should be performed at a minimum during commissioning.			
NPCC CP9 RSWG	Yes	Yes	NPCC participating members believe that although in concept that collection this information has value, the actual testing required to validate the parameters could be a detriment to reliability. (needs work however doesn't apply to the RRO)
Response: The tests are offline and are not an immediate threat to system reliability.			
John K. Loftis, Jr. – Dominion – Electric Transmission	Yes	Yes	Using the term verify is vague and subject to different interpretations by various entities. Although there is opposition to field testing generating units, it needs to be acknowledged that field testing is the best way to obtain accurate models and parameters for generator equipment. Because of the large volume of tests to perform, and the high cost to perform them, field testing should be phased-in over a 5 to 8 year time period. It is not possible to test all required units within a one year time frame. The Levels of Non-Compliance as written are on a per generator basis, and will not work well for entities that have a large number of generators. In addition, because the details of the requirements are left up to the RRO the levels of non-compliance should be rewritten as proposed in the comments provided by the SERC Planning Standards Subcommittee (PSS).
Response: The applicable methods are to be identified in the RRO's procedure.~~ per MOD-023.~~ The commenter is encouraged to offer assistance in developing the regional procedures.~~The commenter is encouraged to participate in the regional process for developing that~~			

~~procedure.~~ The drafting team is ~~proposing a phased approach. The RRO procedure should also specify a practical schedule.~~recommending that this standard be field tested before being finalized. The objective is to have verified capability data from each generator that is required to provide data, whether an entity has one generator or many. Compliance violations should be reported so as to not unfairly characterize the extent of the violation. The regional procedures are required to include generating unit exemption criteria including documentation of those units that are exempt from a portion or all of the procedures for verifying generation equipment data.			
PPL Corporation	Yes	Yes	Generating units also provide a vital dynamic response to system voltage transients and an important voltage regulation function. PPL supports the objective of the proposed standard to verify that these functions are modeled correctly. PPL believes that real-time operational data can provide much of the data required by the Regional Reliability Organizations to verify the modeling of a generator's dynamic response to transients and whether or not the generator is following its voltage or reactive schedule. While PPL believes there is some value in performing certain off-line tests such as a voltage step test, we do not see a need to repeat these tests unless modifications have been made to a generator's excitation systems. In addition, units of size less than 70 MWs should be exempt. PPL believes that a NERC standard should require all Generator Owners to have their Automatic Voltage Regulators (AVRs) in service and to immediately report any AVR outages to the system operator
Response: The applicable methods are to be identified in the RRO's procedure.~~, per MOD-023.~~ The commenter is encouraged to offer assistance in developing the regional procedures.~~The commenter is encouraged to participate in the regional process for developing that procedure. Risk and cost factors should be considered in development of the regional procedure.~~ Exemptions for verification are to be addressed in the RRO's procedure.~~, per MOD-023.~~ The requirement to have AVR in service and report outages is addressed in VAR-001 and VAR-002.			
Midwest Reliability Organization	Yes	Yes	Assume the standard allows for the RRO to approve of exemption for smaller units?

Response: Yes.			
Transmission Issues Subcommittee	Yes	Yes	There is the potential for wide variance in verification procedures among RROs. The RRO requirements should require physical testing of the generator excitation system. This standard should include a requirement for NERC review of the RRO's verification procedures. The standard should establish a maximum five year period for verification of capabilities, unless there is a change in equipment or a setting change, at which time the generator excitation system should be retested.
Response: The drafting team believes and is supported by industry comment, that alternative methods for verification of data can also be valid. The applicable methods are to be identified in the RRO's procedure. The commenter is encouraged to offer assistance in developing the regional procedures.~~per MOD-023. Commenters are encouraged to participate in the regional process for developing that procedure.~~ The drafting team is ~~proposing a phased implementation. The RRO procedure can define a practical schedule for verification and reporting of data.~~recommending that this standard be field tested before it is finalized.			
Peter Burke – American Transmission Co.	Yes	Yes	R2 should this read "… shall verify the data submitted for use in dynamic models.."?
Response: The drafting team has included this clarification.			
Gerald Rheault – Manitoba Hydro	Yes	Yes	Include a requirement to coordinate unit protection settings with the excitation limiters and frequency of testing required. R3.7: What is meant by "method of verification"?
Response: Protection coordination is required in PRC-019. Methods of verification will be defined by the RRO's procedure.~~, per MOD-023.~~			
IESO – Ontario	Yes	Yes	R4 - Needs to clarify that when is the data required - This should be consistent with requirements R1.2 as stated in MOD-028-1

Response: The RRO procedure will define when the data is required.			
Jerry Nicely – TVA Nuclear Generation	Yes	Yes	R5 should allow for alternatives to the open-circuit step response test, such as on-line transient data collection methods.
Response: The drafting team believes the open circuit step test is required. The RRO procedure can define alternative verification methods.			
Xcel Energy – Northern States Power	Yes	Yes	R4 - The specific contained in R5 (exciter field voltage and current data for brushless units) needs to be added to R4 as the same rules apply.
Response: The requirements have been merged.			
D. Byran Guy – Progress Energy, Inc.	Yes	Yes	PEC supports the language used that allows fo alternate methods of verifing data for modeling other than testing. R4- Delete last sentence which is covered in R5. Revise R5 to replace "…chart recordings showing…" with "…data that includes..."
Response: Requirements have been merged ~~(R4 and R5 are now R3)~~ and requirement for charts removed.			
Resource Issues Subcommittee	Yes	Yes	1. R5 should allow for alternatives to the open-circuit step response test, such as on-line transient data collection methods. 2. RIS believes that consideration should be given in this standard to collecting the appropriate data to verify that units will perform as simulated. All of the information requested in R3 may not be necessary, and should not be required unless specified by the Region.
Response: The drafting team believes the open circuit step test is required. The RRO procedure can define alternative verification methods.			
SERC EC Generation Subcommittee (GS)	Yes	Yes	R5 should allow for alternatives to the open-circuit step response test, such as on-line transient data collection methods.

Response: The drafting team believes the open circuit step test is required. The RRO procedure can define alternative verification methods.			
AEP			Reword the title as follows: Verification of Generator Excitation System and Voltage Control Models. Reword R1 as follows: The Generator Owner shall - - - and applicable Transmission Planner(s) modeling data associated with - - - Organization requirements. The data shall be compatible with the standard excitation system models available in stability programs widely used in the industry. If a new model is necessary for reasonable representation of the equipment, the new model must be developed for industry-wide use. Delete the last sentence in R4. Add R6 as follows: Any field changes made by the Generation Owner or Generator Operator to the verified data described in R1 above shall be re-verified / tested as soon as possible. Such changes, and their associated verification/testing results, shall be coordinated with the Transmission Owner, Planning Authority, and Transmission Planners, and reported to the region within 30 days. D1.2 Compliance Monitoring Period and Reset Timeframe: At installation of new equipment. Beyond that, when equipment is changed out or when setting changes are made. (Once this data becomes established and there are no further equipment changes, it is unnecessary and burdensome to keep repeatedly doing compliance reviews.) D1.3 Data Retention: Generator Owner shall retain commissioning and test reports and data indefinitely or until unit is retired. D1.4 Additional Compliance Information: The Generator Owner shall demonstrate compliance through transmitting the verified data to Transmission Owner/Operator/Planner, and through self-certification or audit - - - - as determined by the Compliance Monitor.The Generator Owner shall demonstrate compliance by handing over the requested data.
Response: The title and purpose have been revised for clarification. R1 has been deleted in deference to what was R3 ~~(now R2)~~. R4 and R5 were merged and clarified ~~and are now R3~~. Requirement in commenter's suggested R6 is addressed by new ~~R3~~R2. Compliance monitoring period defines review period for compliance, it does not define the verification period. Periodicity of verification is			

defined by the RRO procedure. Data retention has been changed to current and prior verification data. The additional compliance information is consistent across the new standards being proposed.			
Raj Rana – AEP	Yes	Yes	See AEP Comment
Response: See response to AEP.			
Entergy SERC EC Planning Standards Subcommittee (PSS)	Yes Yes	Yes Yes	The Levels of Non-Compliance as written are on a per generator basis, and will not work well for entities that have a large number of generators. In addition, because the details of the requirements are left up to the RRO, the levels of non-compliance should be rewritten as follows: 2.1. Level 1: Verified generator data were provided and were complete for less than 100% of a generator owner's units as required by the RRO procedures. 2.2. Level 2: Verified generator data were provided and were complete for less than 95% of a generator owner's units as required by the RRO procedures. 2.3. Level 3: Verified generator data were provided and were complete for less than 90% of a generator owner's units as required by the RRO procedures. 2.4. Level 4: Verified generator data were provided and were complete for less than 85% of a generator owner's units as required by the RRO procedures.
Response: The objective is to have verified capability data from each generator that must provide data, whether an entity has one generator or many. Compliance violations should be reported so as to not unfairly characterize the extent of the violation. The regional procedures are required to include generating unit exemption criteria including documentation of those units that are exempt from a portion or all of the procedures for verifying generation equipment data.			
Karl Kohlrus - City Water, Light & Power	No Answer	Yes	
Howard Rulf - WE Energies	Yes	Yes	

Michael C. Calimano – NYISO	Yes	Yes	
Alan Adamson – NYSRC	Yes	Yes	
Dan Griffiths – PA Office of Consumer Advocate	Yes	Yes	
Ed Riley – California ISO	Yes	Yes	
ISO/RTO Council Standards Review Committee	Yes	Yes	
Doug Hohbough – First Energy Corp.	Yes	Yes	
Consolodated Edison	Yes	Yes	

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

This proposed standard is a translation of planning measure II.B.M4 and II.B.M6, which were not included in the approval Version 0 reliability standards because they required further work.

Development Steps Completed:

1. A SAR was posted from December 2, 2004, through January 7, 2005.
2. The SAC appointed a standard drafting team on January 13, 2005.
3. The drafting team posted its response to SAR comments and all other historical comments on April 19, 2005.
4. The drafting team posted Draft 1 of the standard on April 21, 2005.

Description of Current Draft:

This is a first draft of the standard to be posted for industry comment.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Consider comments on 2nd draft~~Close Draft 1 comment period.~~	To be determined~~June 6, 2005~~
2. Conduct field test~~Review comments from industry posting and determine if the draft standard is ready for ballot.~~	To be determined~~July 15, 2005~~
3. Revise standard based on field test results ~~Post for 30-day pre-ballot period.~~	To be determined~~August 1, 2005~~
4. Post field test results and revised standard for comment~~Conduct ballot.~~	To be determined~~September 1, 2005~~
5. Respond to comments~~Post for 30-day period prior to Board adoption.~~	To be determined~~October 1, 2005~~
6. Post revised standard for 30-day pre-ballot review~~Board adoption and effective date.~~	To be determined~~November 1, 2005~~
~~6.~~7. Ballot standard	To be determined
~~6.~~8. Post standard for 30-day BOT review	To be determined
~~6.~~9. BOT adoption	To be determined
~~6.~~10. Effective date	To be determined.

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

No new definitions are proposed for this standard.

A. Introduction

1. **Title:** **Verification ~~and Modeling~~ of Generator Excitation Systems and Voltage ~~Controls~~Control Model Data**

2. **Number:** MOD-026-1

3. **Purpose:** To ensure accurate information on ~~verify~~ generator excitation system functions (including voltage regulator controls, limiters, compensators, and power system stabilizers, if applicable) ~~are~~ is available ~~and consistent with~~for models used to assess Bulk Electric System reliability.

4. **Applicability**

   4.1. Regional Reliability Organization.

   4.2. Generator Owner.

5. **Proposed Effective Date:** ~~November 1, 2005.~~To be determined.

B. Requirements

R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of generator excitation system functions including voltage regulator contols, limiters, compensators, and power system stabilizers. These procedures shall include the following:

R1.1. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.

R1.2. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data, commissioning data, performance tracking, simulation, analysis, field verification of equipment settings, testing, and comparison with disturbance monitoring data, etc.

R1.3. Periodicity and schedule of model and data verification and reporting.

R1.4. Verification of models and data as related to generator excitation system functions:

R1.4.1. Models depicting the type of excitation / voltage regulator control system (static, brushless, rotating, manufacturer, etc.).

R1.4.2. Data used in models for voltage regulator controls.

R1.4.3. Static set points for under and over excitation limiters.

R1.4.4. Line drop compensators.

R1.4.5. Gains and time constants.

R1.4.6. Open circuit test response data showing generator field voltage and generator terminal voltage (exciter field voltage and current data for brushless units).

R1.4.7. Power system stabilizer data and test results, if applicable.

R1.4.8. Method of verification, including the date of verification, the voltage regulator mode of operation, and the voltage regulator control settings during the verification.

R2. The Regional Reliability Organization shall ~~make~~provide its generator excitation system data verification and reporting procedures, and any changes to those procedures, ~~available~~ to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.

R3. The Generator Owner shall follow its Regional Reliability Organization's procedure for verifying its generator excitation system data per MOD-026 R1.

~~R1.~~The ~~The Generator Owner shall, within 30 calendar days of a request, provide to the Regional Reliability Organization and applicable Transmission Planner(s) data associated with the generator excitation system functions (including voltage regulator controls, limiters, compensators, and power system stabilizers, if applicable), in accordance with Regional Reliability Organization requirements.~~

~~R2.The Generator Owner shall verify the data submitted for useused in dynamic models for excitation systems (including power system stabilizers and other devices, if applicable) in accordance with Regional Reliability Organization requirements established per MOD-023.~~

~~R3.The Generator Owner shall, within 30 calendar days of a request, provide to the Regional Reliability Organization and applicable Transmission Planner and Planning Authority(s) the results of excitation system model and data verification, including but not limited to the following verified information, in accordance with Regional Reliability Organization requirements established per MOD-023:~~

~~R3.1.Type of excitation / voltage regulator control system (static, brushless, rotating, manufacturer, etc.).~~

~~R3.2.Voltage regulator controls.~~

~~R3.3.Static set points for uunder nder and over excitation limiters.~~

~~R3.4.Line drop compensators.~~

~~R3.5.Gains and time constants.~~

~~Open circuit test response data showing generator field voltage and generator terminal voltage (exciter field voltage and current data for brushless units).~~

~~R3.6.Power system stabilizer data and test results, if applicable.~~

~~R3.7.Method of verification, including the date, the voltage regulator mode of operation, and the voltage regulator control settings during the verification.~~

R4. ~~The~~ Generator Owner that ~~s~~ installs a ~~ing~~ new or refurbished excitation system~~s~~ shall provide design data for ~~new or refurbished excitation~~th~~ose~~at system~~s~~ prior to the in-service date as required by the Regional Reliability Organization procedure. The Generator Owner shall ~~and~~ provide updated data once the unit is in service, including ~~. O~~open circuit test response ~~chart recordings~~data ~~shall be provided~~ showing generator field voltage and generator terminal voltage. (WILL THIS BE IN THE SCHEDULE?)

~~R5.The Generator Owner shall provide open circuit test response chart recordings showing generator field voltage and generator terminal voltage (exciter field voltage and current data for brushless units) in accordance with Regional Reliability Organization requirements.~~

C. Measures

M1. The Regional Reliability Organization shall have available for inspection a procedure for the verification and reporting of generator excitation system data in accordance with MOD-025 R1.

M2. The Regional Reliability Organization shall have evidence that its procedure, and any revisions to that procedure, for verification and reporting of generator excitation system data was provided to affected Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners within 30 calendar days of approval.

M3. The Generator Owner shall have evidence it provided the Regional Reliability Organization and appropriate Transmission Planner and Planning Authority with verification of its generator excitation system, consistent with the Regional Reliability Organization procedure.

~~M1. The Generator Owner shall document verification of the excitation system functions (including voltage regulator controls, limiters, compensators, and power system stabilizers, if applicable) and shall make such documentation available to the Regional Reliability Organization.~~

~~M2. The Generator Owner shall have evidence it provided the Regional Reliability Organization and applicable Transmission Planner and Planning Authority(s) with verification results for the excitation system functions (including voltage regulator controls, limiters, compensators, and power system stabilizers, if applicable), consistent with the Regional Reliability Organization procedure, within 30 calendar days of a request.~~

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

For Regional Reliability Organization: NERC.

For Generator Owner: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

The Generator Owner shall retain information from the most current and prior verification.~~Generator Owner shall retain assessments for two years.~~

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Regional Reliability Organization and Generator Owner shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. **Levels of Non-Compliance for Regional Reliability Organization:**

   2.1. Level 1: Procedures did not meet either MOD-026 R1.1 or~~,~~ R1.3 ~~or R2~~.

   2.2. Level 2: Procedures did not meet ~~two of the following~~ requirement~~s:~~ MOD-026 R1.2~~1, R1.3 and R2~~.

   2.3. Level 3: The procedures were not provided as required by MOD-025 R2 or the ~~P~~procedures did not meet two of the following requirements: MOD-026-1 R1.1, R1.2.or R1.3.

   2.4. Level 4: Procedures did not meet one of the following requirements:~~either~~ MOD-026 R1.4.1, R1.4.2, ~~or~~ R1.4.3, R1.4.4, R1.4.5, R1.4.6, R1.4.7 or R1.4.8.

3. **Levels of Non-Compliance for Generator Owner:**

   3.1. Level 1: There shall be a level one non-compliance if either of the following conditions is present:

   Verified generator excitation system function data was provided but was missing some of the information required in the method of verification required by regional procedure as specified in MOD-025 R1.4.8. or

   ~~2.1.~~3.1.1

   3.1.2 Any of the information required by regional procedure as specified in the eight elements of R1.4 did not meet the regional periodicity and schedule of model and data verification and reporting~~Generator excitation system model and data verificationvoltage regulator controls and limit function information, were provided but were incomplete in one area as specified in MOD-026 R1 and R1, R2 and R5.~~

   ~~2.2.~~3.2. Level 2: Verified generator excitation system function data was provided but was missing some of the information required in any one of the following requirements: MOD-025 R1.4.1, R1.4.2, R1.4.3, R1.4.4, R1.4.5, R1.4.6 or R1.4.7~~Not applicable~~.

   ~~2.3.~~3.3. Level 3: Verified generator excitation system function data was provided but was missing some of the information required in any two of the following requirements: MOD-025 R1.4.1, R1.4.2, R1.4.3, R1.4.4, R1.4.5, R1.4.6 or R1.4.7~~Generator Owner provided design data for new or refurbished excitation systems prior to the in-service date but was incomplete as required by the Regional Reliability Organization procedure or provided incomplete updated data once the unit is in service as specified in MOD-026 R3 and R4~~.

   ~~2.4.~~3.4. Level 4: Verified generator excitation system function data was provided but was missing some of the information required in any three of the following requirements: MOD-025 R1.4.1, R1.4.2, R1.4.3, R1.4.4, R1.4.5, R1.4.6 or R1.4.7~~Generator Owner did not verify the data used in dynamic models for excitation systems (including power system stabilizers and other devices, if applicable) in accordance with Regional Reliability Organization requirements as specified in MOD-026 R1, R2, or R3~~.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

Members	Reliability Need?	Acceptable Translation ?	Comments
IESO			(From Q 4 – Other comments) We suggest updating requirements to make these more explicit for validation of Deadband and Droop.
Response: There is more to modeling frequency response than droop and deadband. Controls on units today are typically more complex and have overrides. System modeling requires more than droop and deadband.			
PPL Corporation			(From Q 4 – Other comments) The Regional Reliability Organization needs to determine the frequency and overall criteria required for any generation testing in support of these new standards. The needs basis shall only evaluate units that have a significant affect on the safe and reliable operation of the transmission system. Any test that is required on generator equipment needs to be subject to a risk analysis where the value of the test is evaluated against the risk that such test would impact the generation equipment and transmission system. Only units or stations that have a significant affect on the system should be tested. Nuclear units should be exempted from on-line testing unless the Nuclear Generator Owner can demonstrate through the 10CFR50.59 screening process that such testing is not an Unreviewed Safety Question (USQ). PPL believes that real-time operational data could be used in lieu of on-line testing in some instances to validate the range of reactive capabilities.
Response: The drafting team agrees. The RRO was assigned responsibility for developing these procedures so that these procedures can reflect regional needs. ~~The RRO has been assigned responsibility for this procedure because regional reliability needs and risk factors need to be considered by the procedure.~~ The regional procedures are required to include generating unit exemption criteria including documentation of those units that are exempt from a portion or all of the procedures for verifying generation equipment data. The commenter is encouraged to offer assistance in developing the regional procedures. ~~The regional procedure should address nuclear plant testing exemptions that would be justified by nuclear safety regulations. The commenter is encouraged to participate in the development of the regional procedure.~~			
SPP Transmission Working Group			(From Q 4 – Other comments) MOD-023 thru 027 should include planning authorities.

Response: The Drafting Team subdivided the requirements in MOD-023 and placed the RRO's requirement to write procedures, and forward those procedures to the Generator Owners, into each of the standards that required the Generator Owner to verify and provide models and data (MOD-024 through MOD-027). The Planning Authority was added as a recipient of the RRO's procedures and as a recipient of the Generator Owner's data in MOD-024 through MOD-027.~~Planning authority added.~~			
Pacific Gas and Electric			Nuclear facility governors are block loaded to prevent electrical transients on the system from affecting the primary plant and testing to verify generator frequency response is probably not practical. Nuclear facilities may need an exemption from this standard.
Response: The regional procedures are required to include generating unit exemption criteria including documentation of those units that are exempt from a portion or all of the procedures for verifying generation equipment data. ~~Exemption criteria are to be addressed in the RRO procedure.~~			
Tennessee Valley Authority	Yes	No	The Regional Reliability Organization is required by VAR-004 to establish voltage/frequency dip criteria, but the only standard that addresses the generator's capability to meet these criteria is this one. This standard should therefore be more specific about providing information about when the generator will trip. Generator trip settings (under/over frequency and voltage ride thru capability) should be provided to the Transmission Planner. (Essential to coordinate with UFLS).
Response: Addressed in the PRC standards on UFLS.			
Carol L. Krysevig – Allegheny Energy Supply Co.	Yes	No	MOD-027-1 goes far beyond verifying that a governor is in service or blocked. While modern electronic governors do have accurate dialed in settings for droop, deadband and other control limiters older mechanical governors do not. Their expected response may be at best a guess. Not knowing of a viable test for frequency response I do not agree with this standard as written. On a per unit basis the most accurate indicator of frequency response was evident on August 14, 2003. It is believed that the use of system event recording devices is the only way to accurately afford predictable models for reliability studies.
Response: Drafting team agrees and is recommending a field test to determine appropriate methods to verify generator frequency response.			
Samuel W. Leach – TXU Power	Yes	No	The proposed standard should be more specific as to acceptable method or methods to be used to provide verification of the speed/load governor characteristics.
Response: Drafting team agrees and is recommending a field test to determine appropriate methods to verify generator frequency response.			

Cinod Kotecha Kathleen Goodman – ISO-NE NPCC CP9 RSWG	Yes Yes Yes	No No No	Drafting Team to verify that the testing requirements that appear in the "S" language in the original Standard, has been dropped, was this intentional? There is also an analysis currently underway regarding the response of unit governors on August 14 and also how they relate to existing system models. Results of the analysis need to be weighed in developing the appropriate standard.

Response: The intent of the 'S' statements for IIB and III C have been translated into the new standards. ~~language established broad system goals~~The 'S' statements said:

> **II.B.S5.** Generation equipment shall be tested to verify that data submitted for steady-state and dynamics modeling in planning and operating studies is consistent with the actual physical characteristics of the equipment. The data to be verified and provided shall include generator gross and net dependable capability, gross and net reactive power capability, voltage regulator controls, speed/load governor controls, and excitation systems.
>
> **III.C.S5.** Prime mover control (governors) shall operate with appropriate speed/load characteristics to regulate frequency.

The proposed standards require that generator data be verified, but don't require that 'testing' be used because there are other methods of verifying data.

~~. The proposed new standards address specific performance requirements of responsible entities.~~

The proposed standard MOD-027 requires the generator owner to identify how its unit will respond to both short tem and long term frequency responses – and requires the generator owner to identify the method used to make this determination. This supports the intent of the 'S' statement for III C.

Drafting team agrees and is recommending a field test to determine appropriate methods to verify generator frequency response. Performance analysis from the August 2003 blackout may be useful in determining methods to verify frequency response.

Consolodated Edison Alan Adamson – NYSRC	Yes Yes	No No	The drafting team should verify that the testing requiremtns that appear in the "s" language in the original Standard has been dropped, was this intentional?

Response: ~~The 'S' language established broad system goals. The proposed new standards address specific performance requirements of responsible entities.~~ The intent of the 'S' statements for IIB and III C have been translated into the new standards. The 'S' statements said:

> **II.B.S5.** Generation equipment shall be tested to verify that data submitted for steady-state and dynamics modeling in planning and operating studies is consistent with the actual physical characteristics of the equipment. The data to be verified and provided shall include generator gross and net dependable capability, gross and net reactive power capability, voltage regulator controls, speed/load

governor controls, and excitation systems. **III.C.S5.** Prime mover control (governors) shall operate with appropriate speed/load characteristics to regulate frequency. The proposed standards require that generator data be verified, but don't require that 'testing' be used because there are other methods of verifying data. The proposed standard MOD-027 requires the generator owner to identify how its unit will respond to both short tem and long term frequency responses – and requires the generator owner to identify the method used to make this determination. This supports the intent of the 'S' statement for III C.			
Southern Company Generation Southern Company – Transmission	Yes Yes	No No	SoCo Generation recommends the SDT better define the requirements of this standard. R2.2 should be deleted and may require a separate SAR to better define the requirements. The industry has not established a safe and effective means for determining the response of a generating plant to changes in system frequency. Our assessment indicates the response of generator speed and the MW output depend on the overall control system applied at the plant not just the governor. If these requirements are adopted then SoCo Generation's comments for MOD-025 regarding field testing, implementation, levels of non compliance and reportability should apply.
Response: Drafting team ~~agrees and~~ is recommending a field test to determine appropriate methods to verify generator frequency response. Performance analysis from the August 2003 blackout may be useful in determining methods to verify frequency response.			
Kenneth Dresner – FirstEnergy Solutions	Yes	No	A standardize timeframe of 30 business days or greater to provide the data should be retained in the proposed standard The request for the nonfunctioning or blocked speed/load governor data needs a duration timeframe of possiblity rolling 12 month period since the other requirements of this proposed standard have a frequency of every five years
Response: The standard was revised to include a requirement that data be provided within 30 calendar days of a request. (This time period may need to be modified based on the results of field tests.) The drafting team is proposing a field test to determine appropriate methods for verification of generator frequency response. ~~It is premature to set reporting times until the methods are settled.~~			

Wing Joe- BC Hydro	No	No	It may be unreasonable to expect that generator owners (or anyone else) in the electric utility industry conduct test to determine how the unit speed and real power output changes in response to frequency transients.
Response: Drafting team agrees and is recommending a field test to determine appropriate methods to verify generator frequency response. Performance analysis from the August 2003 blackout may be useful in determining methods to verify frequency response.			
Constellation Generation Group	Yes	No	Generator can only provide design data. Response to responses to frequency excurions can not be measured, frequency characteristic is unknown and can vary. How can generator come up with data?
Response: Drafting team ~~agrees and~~ is recommending a field test to determine appropriate methods to verify generator frequency response. Performance analysis from the August 2003 blackout may be useful in determining methods to verify frequency response.			
SPP Transmission Working Group	Yes	No	Title should read VERIFICATION OF GENERATOR SPEED GOVERNING SYSTEM MODELS . Change purpose to first sentence of II.B.S5. R1 & R2 should include the Planning Authority. Refer to Funtional Model, Planing Authority, 1c.
Response: The proposed title and purpose do not fit the scope of the standard, which is not limited to speed governor and verification of models. The Planning Authority was added as a recipient of the RRO's procedures and as a recipient of the Generator Owner's data. ~~Planning authority has been added.~~			
Ronnie Frizzell - Arkansas Electric Coop. Corp.	Yes	No	R1 & R2 should include the Planning Authority. Refer to Functional Model, Planning Authority, 1C.
Response: The Planning Authority was added as a recipient of the RRO's procedures and as a recipient of the Generator Owner's			

data.~~Planning authority included.~~			
Kansas City Power and Light	Yes	No	R1 and R2 should include the Planning Authority.
Response: The Planning Authority was added as a recipient of the RRO's procedures and as a recipient of the Generator Owner's data.~~Planning authority added.~~			
Greg Ludwicki – Northern Indiana Public Service Co.	Yes	No	If the method for response verification is a requirement for dynamic testing, one calendar year is over aggressive for dynamic testing. Our OEM's recommendation for such testing is not periodic, but only to diagnose an apparent change in governor operation or after disassembly and/or replacement of major governor parts. MOD-027B. R1Could you explain how to determine the information that you are requesting. Should the results be based on the system recovering or the system staying below 60 Hz.
Response: Drafting team ~~agrees and~~ is recommending a field test to determine appropriate methods to verify generator frequency response. Performance analysis from the August 2003 blackout may be useful in determining methods to verify frequency response.			
Gred Mason – Dynergy Generation	Yes	No	1. NERC should not eliminate specifying a minimum verification frequency(every 5 years in the current standard).NERC should provide this guidance to the Regions. Regions can always be more stringent when regional needs require more frequent verification. Therefore, suggest adding "every five years" verification requirement in Sections B,R1. 2. Section D,2.1 should reference Section R1 instead of Section R2.2.
Response: Drafting team is recommending a field test to determine appropriate methods to verify generator frequency response, which would also address periodicity of verification. Reference is correct as stated in draft.			
Peter Burke – American Transmission Co.	Yes	No	R1. After "transients," add "and be sustained while frequency remains off normal." R2. change "within 30 days" to "within 30 calendar days."
Response: ~~Clarifications were added.~~The word, 'transients' was replaced with 'deviations' and additional language was added to clarify that the			

<table>
<tr><td colspan="4">data needs to address both initial and longer term frequency deviations. This supports the intent of your suggestion.

The ’30 days’ was changed to ’30 calendar days’ as suggested.</td></tr>
<tr><td>Midwest Reliability Organization</td><td>Yes</td><td>No</td><td>Assume the standard allows for the RRO to approve of exemption for smaller units?

R1. After "transients", add "and be sustained while frequency remains off nominal".

R2. Change "within 30 days" to "within 30 calendar days".

Levels of non-compliance. Where "some" is used for non-compliance, is it possible to define further?

Correct proposed effective date under A5 from October 1 to November 1.</td></tr>
<tr><td colspan="4">Response: The regional procedures are required to include generating unit exemption criteria including documentation of those units that are exempt from a portion or all of the procedures for verifying generation equipment data.

~~Exemptions are addressed in RRO procedure.~~

The word, ‘transients’ was replaced with ‘deviations’ and additional language was added to clarify that the data needs to address both initial and longer term frequency deviations. This supports the intent of your suggestion.

The ’30 days’ was changed to ’30 calendar days’ as suggested. ~~Clarified R1.~~

~~R2 corrected.~~

"Some information missing" simply means the data is not complete. Note that the drafting team is recommending that this standard be field tested and will wait for the results of the field tests before fine tuning the levels of non-compliance.

Drafting team is recommending a field test to determine appropriate methods to verify generator frequency response. That will delay implementation and the proposed effective date has been changed to, ‘To be determined’.</td></tr>
<tr><td>IESO – Ontario</td><td>Yes</td><td>No</td><td>R2.1 should be updated to include requirements to report the status immediately.

Drafting Team should verify that the testing requirements that appear in the "S" language in the original Standard has been dropped. Is this intentional?</td></tr>
<tr><td colspan="4">Response: This standard addresses data for modeling, not real-time operations.

The intent of the 'S' statements for IIB and III C have been translated into the new standards. The ‘S’ statements said:

II.B.S5. Generation equipment shall be tested to verify that data submitted for steady-state and dynamics modeling in planning and</td></tr>
</table>

operating studies is consistent with the actual physical characteristics of the equipment. The data to be verified and provided shall include generator gross and net dependable capability, gross and net reactive power capability, voltage regulator controls, speed/load governor controls, and excitation systems. **III.C.S5.** Prime mover control (governors) shall operate with appropriate speed/load characteristics to regulate frequency. The proposed standards require that generator data be verified, but don't require that 'testing' be used because there are other methods of verifying data. The proposed standard MOD-027 requires the generator owner to identify how its unit will respond to both short tem and long term frequency responses – and requires the generator owner to identify the method used to make this determination. This supports the intent of the 'S' statement for III C. ~~The 'S' language established broad system goals. The proposed new standards address specific performance requirements of responsible entities.~~			
Gerald Rheault – Manitoba Hydro	Yes	No	R2.1: Why aren't GOs required to report non-functioning or blocked speed/load governor controls immediately? As written, if there is not a request, the blocked speed/load governor would never be reported. R2.2: the frequency response test should be a physical test. Frequency of testing should be specified.
Response: This standard addresses data for modeling, not real-time operations. Drafting team is recommending a field test to determine appropriate methods to verify generator frequency response. Performance analysis from the August 2003 blackout may be useful in determining methods to verify frequency response.			
SPP Generation Working Group	Yes	No	R2.1 To verify this data each individual unit will need to be tested. It is anticipated that part of this testing would include purposely tripping of the unit off line to obtain some data.. For this to occur, a high level of coordination is needed between the balancing authority, generation owner and pool. Extra caution must be taken with this type testing to help ensure the reliability of the system is not impacted and the unit is not damaged. Hence the frequency of this type test should be held to a minimum. R2.2 Same concerns as R2.1. Hence the frequency of this type test should be held to a minimum. Compliance: Many of these tests require the unit to be off line. Some units are scheduled to be on line over 18 months prior to an overhaul. Taking the unit off line, strictly for testing, could be very costly due to the replacement cost of energy might be natural gas as opposed to coal that the unit to be tested is burning. Hence the time between tests must to be longer

			then one year. If a company has similar units, we would propose that one unit be tested and those characteristics would be applied to other similar units in the company's fleet, similar to WECC's testing procedure.This testing will require sophisticated monitor equipment. GWG believes a minimum of a five year testing cycle is more appropriate
Response: Drafting team agrees and is recommending a field test to determine appropriate methods to verify generator frequency response. Performance analysis from the August 2003 blackout may be useful in determining methods to verify frequency response.			
FRCC	Yes	No	In R2.2. delete everything after the comma (including date conditions of the verification). This phrase only applies if there is a system event that the Generator Owners could use for verification.
Response: The date and conditions of verification are important information for verification.			
Mark Kuras – MAAC Multi-Regional Modeling Working Group	Yes Yes	No No	Recommended new R3 - The Generator Owner shall provide the TP with information on any under frequency protection set at frequencies at or above the lowest stage of regional UFLS trip settings. Recommended new R4 - If the governor and prime mover model does not conform to an IEEE standard or PSSE or PSLF/PSDS standard library model, generator owner shall be required to have a user-defined model written and validated. Delete text under Additional Compliance Information because it is up to the region as to how compliance will be measured. This text adds nothing to the standard.
Response: Coordination with UFLS does not apply to this standard, which is focused on verification of generator frequency response. The suggested requirements to improve consistency of the quantitative data reported, including use of IEEE standards can be incorporated into the RRO procedure. The drafting team does not believe there is sufficient consensus on these requirements for reporting of quantitative data to include in a NERC standard at this time. ~~Additional compliance information is standard language.~~The compliance information identifies how compliance with NERC standards will be determined. If the compliance information indicates that compliance will be measured through annual self-certification, then that is how the Compliance Monitor must measure compliance with this standard. It is not completely up to the Region to determine how to measure compliance with NERC Standards.			
Joseph D Williamson – PJM	No	No	Level 1 goes beyond the requirement by stating "verification" Level 3 can't be measured since Requirement 1 doesn't state what information is to be included.

			Level 4 is confusing and seems to try and catch four different elements of only two requirements
Response: ~~Method of verification is in R2.2, consistent with Level 1.~~ ~~L3 – the information is to be defined in a RRO procedure.~~ ~~L4 – each listed element is proposed as a cause for a L4 violation.~~The drafting team is recommending that this standard be field tested and will wait for the results of the field tests before fine tuning the levels of non-compliance.			
Individual Members of CCMC	Yes	No	Does Level 1 only address the “date and conditions of the verification”? Something more important to reliability seems to be missing. Level 3 can’t be measured since Requirement 1 doesn’t state what information is to be included. “Conditions” in R2.2 needs to be expanded so that compliance will be meaningful for reliability. Level 4 is confusing and seems to try and catch four different elements of only two requirements. It appears to be judging compliance on 4 issues. Rewording may be needed for clarity.
Response: ~~Drafting team is recommending a field test to determine appropriate methods to verify generator frequency response.~~ The drafting team is recommending that this standard be field tested and will wait for the results of the field tests before fine tuning the levels of non-compliance. ~~Method of verification is in R2.2, consistent with Level 1.~~ ~~L3 – the information is to be defined in a RRO procedure. Conditions will be addressed in RRO procedure~~ ~~L4 – each listed element is proposed as a cause for a L4 violation.~~			

NERC Interconnection Dynamics Working Group	Yes	No	Title needs to be changed: Verification of Generating Unit Primary Frequency Response — R1 – The Generator Owner shall provide modeling data to the…Organization requirements. The data shall be compatible with the standard speed governing system models available in stability programs widely used in the industry. If a new model is necessary for reasonable representation of the equipment, the new model must be developed for industry-wide use. — Add R3 as follows: The generating unit turbine-governor model data shall be provided to the TP and RRO. The above model/data shall be compatible with the standard speed governor models available in stability programs widely used in the industry. If a new model is necessary for reasonable representation of the equipment, the new model must be

			developed for industry-wide use. — Add R4 as follows: Any field changes made by the Generation Owner or Generator Operator to the verified data described in R1 above shall be re-verified / tested as soon as possible. Such changes, and their associated verification/testing results, shall be coordinated with the Transmission Owner, Planning Authority, and Transmission Planners, and reported to the region within 30 days.
Response: This standard is addressing longer-term frequency response as well, not just primary (governor) response. Changed 'generator' to 'generating unit'. The suggested requirements to improve consistency of the quantitative data reported, including use of IEEE standards can be incorporated into the RRO procedure. The drafting team does not believe there is sufficient consensus on these requirements for reporting of quantitative data to include in a NERC standard at this time. Re-verification time constraints are to be addressed in the RRO procedure.			
AEP			Reword the title as follows: Verification of Generating Unit Primary Frequency Response Add R3 as follows: The generating unit turbine-governor model block diagram and associated data shall be provided to the TP and RRO. The above model/data shall be compatible with the standard speed governor models available in stability programs widely used in the industry. If a new model is necessary for reasonable representation of the equipment, the new model must be developed for industry-wide use. Add R4 as follows: Any field changes made by the Generation Owner or Generator Operator to the verified data described in R1 above shall be re-verified / tested as soon as possible. Such changes, and their associated verification/testing results, shall be coordinated with the Transmission Owner, Planning Authority, and Transmission Planners, and reported to the region within 30 days. D1.2 Compliance Monitoring Period and Reset Timeframe: At installation of new equipment. Beyond that, when equipment is changed out or when setting changes are made. (Once this data becomes established and there are no further equipment changes, it is unnecessary and burdensome to keep repeatedly doing compliance reviews.) D1.3 Data Retention: Generator Owner shall retain commissioning and test reports and data indefinitely or until unit is retired. D1.4 Additional Compliance Information: The Generator Owner shall demonstrate compliance through transmitting the verified data to Transmission Owner/Operator/Planner, and through self-certification or audit - - - - as determined by the Compliance Monitor.The

			Generator Owner shall demonstrate compliance by handing over the requested data.
Response: This standard is addressing longer-term frequency response as well, not just primary (governor) response. Changed 'generator' to 'generating unit'. The suggested requirements to improve consistency of the quantitative data reported, including use of IEEE standards can be incorporated into the RRO procedure. The drafting team does not believe there is sufficient consensus on these requirements for reporting of quantitative data to include in a NERC standard at this time. Re-verification requirements and time constraints are to be addressed in the RRO procedure. Data retention is for current and prior data. The drafting team believes that is sufficient. The additional compliance information is standard language for the standards.			
Raj Rana – AEP	Yes	Yes	See AEP Comment
Response: See AEP response.			
Michael C. Calimano – NYISO	Yes	Yes	In concept collecting this information has value, the actual testing required to validate the parameters may pose advers reliability risks during testin
Response: Drafting team agrees and is recommending a field test to determine appropriate methods to verify generator frequency response. Performance analysis from the August 2003 blackout may be useful in determining methods to verify frequency response.			
WECC Reliability Subcommittee Mohan Kondragunta – Southern California Edison	Yes Yes	Yes Yes	WECC RS agrees with the removal of the five-year testing requirement and that it should be established by the RRO.
Response: The drafting team agrees.			
Barry Green – Ontario Power	Yes		There is some inconsistency in this package of standards affecting generators, between applicability to generator owner in some cases and generator operator in others. For this

Generation			standard, MOD-027-1, the applicability must lie with the generator operator. In many cases, the owner, by virtue of contractual obligations, would not have the ability to carry out the obligations imposed by this standard. In other cases, ownership could be shared and it would not be appropriate for these obligations to be shared. Therefore, the applicability of this standard more correctly belongs with the generation operator. Alternatively, if NERC chooses to be less prescriptive, it could, for the purposes of the standard, place an obligation on the owner or operator, with an obligation on the region to clarify in each case, the appropriate entity to meet the requirements.
Response: The functional model assigns capability verification to the generator owner. The comment could be an issue when there are joint owners, but in these cases there are agreements to address delegation of this task among the owners.			
John Horakh – MACC	Yes	Yes	Good conversion from prescribed testing to verification. However the Generator Owner may require significant time beyond November 1, 2005 for the initial verification. An effective date of five years beyond Board approval is more realistic.
Response: Drafting team agrees and is recommending a field test to determine appropriate methods to verify generator frequency response. Performance analysis from the August 2003 blackout may be useful in determining methods to verify frequency response.			
PPL Corporation	Yes	Yes	PPL supports the objective of this proposed standard, which is to verify the status of generator primary frequency responses used in models for reliability studies. However, this objective will be severely hampered by the limited amount of information that the Generator Owner can provide, which consists of the governor gain setting (MW per Hz), the droop setting, a deadband setting, and perhaps a time constant. It is also unclear how these parameters could ever be verified in the field, inasmuch as it is not possible to stage the system frequency disturbances that would be required. PPL believes that while the proposed standard's goals are worthy, it may be attempting to achieve a level of modeling precision that is neither necessary nor achievable in practice. A blanket exemption for nuclear units is needed because nuclear regulations prevent these units from having active governor controls, which would override the licensed operators' control of nuclear reactors during system frequency disturbances.
Response: Drafting team agrees and is recommending a field test to determine appropriate methods to verify generator frequency response. Performance analysis from the August 2003 blackout may be useful in determining methods to verify frequency response. The regional procedures are required to include generating unit exemption criteria including documentation of those units that are exempt from a portion or all of the procedures for verifying generation equipment data.			

~~Exemptions will be addressed in the RRO procedure.~~			
John K. Loftis, Jr. – Dominion – Electric Transmission	Yes	Yes	Using the term verify is vague and subject to different interpretations by various entities. Unless specified in another Reliability Standard, a requirement should be added to require generator owners to notify the RA, BA, and/or TO as appropriate as soon as a non-functioning or blocked speed/load governor controls has been identified. The Levels of Non-Compliance as written are on a per generator basis, and will not work well for entities that have a large number of generators. In addition, because the details of the requirements are left up to the RRO, the levels of non-compliance should be rewritten as proposed in the comments provided by the SERC Planning Standards Subcommittee (PSS).
Response: The term, 'verify' has been used in several standards and seems to be accepted by most commenters. The acceptable methods of verifying the data must be identified in the Region's procedures. Requiring notification of the RA, BA and/or TOP of changes in real-time operating conditions is outside the scope of this standard, which is limited to modeling. There are other standards to address these types of real-time notifications. ~~Drafting team agrees and is recommending a field test to determine appropriate methods to verify generator frequency response. Performance analysis from the August 2003 blackout may be useful in determining methods to verify frequency response.~~ ~~The objective is to have verified capability data from each generator, whether an entity has one generator or many. Compliance violations should be reported so as to not unfairly characterize the extent of the violation.~~ The drafting team is recommending that this standard be field tested and will wait for the results of the field tests before fine tuning the levels of non-compliance.			
Resource Issues Subcommittee	Yes	Yes	Consider combining R1 and R2, as they seem to overlap
Response: R1 and R2 were merged to better organize the requirements.			
Joseph F. Buch – Madison Gas and Electric	Yes		R1 indicates that the generator owner is to provide information on the generator response to frequency transients, however, no information on what constitutes a frequency transient is provided. R2.2 indicates that the generator owner is to provide verification of the frequency response however no indication of test criteria is provided and no information on what sort of time resolution for plotting frequency vs load change is provided. Information on older or small units may not be available. It is recommended that this standard undergo field testing to better define the requirements. At the same time the benefits of providing data on small units (<50 MW) or those of older vintage should be evaluated).

Response: Drafting team agrees and is recommending a field test to determine appropriate methods to verify generator frequency response. Performance analysis from the August 2003 blackout may be useful in determining methods to verify frequency response. The regional procedures are required to include generating unit exemption criteria including documentation of those units that are exempt from a portion or all of the procedures for verifying generation equipment data.			
SERC EC Planning Standards Subcommittee (PSS) Entergy	Yes Yes	Yes Yes	Unless specified in another Reliability Standard, a requirement should be added to require generator owners to notify the RA, BA, and/or TO as appropriate as soon as a non-functioning or blocked speed/load governor controls has been identified. The Levels of Non-Compliance as written are on a per generator basis, and will not work well for entities that have a large number of generators. In addition, because the details of the requirements are left up to the RRO, the levels of non-compliance should be rewritten as follows: 2.1. Level 1: Verified generator data was provided and was complete for less than 100% of a generator owner's units as required by the RRO procedures. 2.2. Level 2: Verified generator data was provided and was complete for less than 95% of a generator owner's units as required by the RRO procedures. 2.3. Level 3: Verified generator data was provided and was complete for less than 90% of a generator owner's units as required by the RRO procedures. 2.4. Level 4: Verified generator data was provided and was complete for less than 85% of a generator owner's units as required by the RRO procedures.
Response: This standard is focuses on verification of model data, not real-time operating information. The drafting team is recommending that this standard be field tested and will wait for the results of the field tests before fine tuning the levels of non-compliance. ~~The objective is to have verified capability data from each generator, whether an entity has one generator or many. Compliance violations should be reported so as to not unfairly characterize the extent of the violation.~~			
Xcel Energy – Northern States Power	Yes	Yes	
SERC EC Generation Subcommittee	Yes	Yes	

(GS)			
Deborah M. Linke – US Bureau of Reclamation	Yes	Yes	
Karl Kohlrus - City Water, Light & Power	Yes	Yes	
Rebecca Berdahll – Bonneville Power Administration Karl Bryan – Corp of Engineers Jay Sietz – US Bureau of Reclamation Brenda Anderson	Yes	Yes	
ISO/RTO Council Standards Review Committee	Yes	Yes	
Doug Hohbough – First Energy Corp.	Yes	Yes	
D. Byran Guy – Progress Energy, Inc.	Yes	Yes	
Jerry Nicely – TVA Nuclear	Yes	Yes	

Generation			
Ed Riley – California ISO	Yes	Yes	
Howard Rulf - WE Energies	Yes	Yes	
Dan Griffiths – PA Office of Consumer Advocate	Yes	Yes	

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

This proposed standard is a translation of planning measure II.B.M5 and III.C.M9, which were not included in the approval Version 0 reliability standards because they required further work.

Development Steps Completed:

1. A SAR was posted from December 2, 2004, through January 7, 2005.
2. The SAC appointed a standard drafting team on January 13, 2005.
3. The drafting team posted its response to SAR comments and all other historical comments on April 19, 2005.
4. The drafting team posted Draft 1 of the standard on April 21, 2005.

Description of Current Draft:

This is a first draft of the standard to be posted for industry comment.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Close Draft 1 comment period.	June 6, 2005
2. Review comments from industry posting and determine if the draft standard is ready for ballot.	July 15, 2005
3. Post for 30-day pre-ballot period.	August 1, 2005
4. Conduct ballot.	September 1, 2005
5. Post for 30-day period prior to Board adoption.	October 1, 2005
6. Board adoption and effective date.	November 1, 2005

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

No new definitions are proposed for this standard.

A. Introduction

1. **Title:** **Verification and Status of ~~Generator~~ Generating Unit Frequency Response**
2. **Number:** MOD-027-1
3. **Purpose:** To provide verification and status of generator primary (other than Automatic Generation Control) frequency response for use in models for reliability studies.
4. **Applicability**
   - **4.1.** Regional Reliability Organization
   - **4.2.** Generator Owner.
5. **Proposed Effective Date:** ~~October 1, 2005~~To be Determined.

B. Requirements

R1. The Regional Reliability Organization shall establish and maintain procedures to address verification and status of generator unit frequency response. These procedures shall include the following:

- **R1.1.** Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.
- **R1.2.** Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data, commissioning data, performance tracking, simulation, analysis, field verification of equipment settings, testing, and comparison with disturbance monitoring data, etc.
- **R1.3.** Periodicity and schedule of model and data verification and reporting.
- **R1.4.** Verification of data as related to generator frequency response:
  - **R1.4.1.** Data characterizing how the unit speed and real power output are expected to change in response to initial and longer-term frequency deviations, in accordance with Regional Reliability Organization requirements per MOD-023.
  - **R1.4.2.** Method of verification of the generator frequency response, including date of the verification and conditions of the verification.
  - **R1.4.3.** Indication of non-functioning or blocked speed/load governor controls, or models and data for controls that influence speed/load governor controls. (IS NOT THIS COVERED IN VAR-002?)

R2. The Regional Reliability Organization shall ~~make~~~~PROVIDE~~provide its verification and status of generator unit frequency response verification and reporting procedures, and any changes to those procedures, ~~available~~ to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedures within 30 calendar days of the approval.

R3. The Generator Owner shall follow its Regional Reliability Organization's procedure for verifying and reporting the status of its generator unit frequency response per MOD-027 R1.

~~R1. The Generator Owner shall provide data the following information to the Transmission Planner, Planning Authority, Transmission Operator, and Regional Reliability Organization within 30 calendar days of a request:~~

~~Data characterizing how the unit speed and real power output are expected to change in response to initial and longer-term frequency transients deviations, in accordance with Regional Reliability Organization requirements per MOD-023.~~

~~Method of verification of the generator frequency response, including date and conditions of the verification.~~

~~R2. The Generator Owner shall provide the Regional Reliability Organization and applicable Transmission Planner(s) with the following information within 30 days of a request:~~

~~R2.1. Non-functioning or blocked speed/load governor controls, or controls that influence speed/load governor controls.~~

~~R2.2. Method of verification of the generator frequency response, including date and conditions of the verification.~~

C. Measures

~~M1. The Generator Owner shall have evidence it provided the Regional Reliability Organization, Transmission Planner, Planning Authority, and Transmission Operator with the information required in R1 and R2 within 30 calendar days of a request.~~

M1. The Regional Reliability Organization shall have available for inspection a procedure for verifying and reporting the status of generator unit frequency response in accordance with MOD-027 R1.

M2. The Regional Reliability Organization shall have evidence that its procedure, and any revisions to that procedure, for verification and reporting the status of generator unit frequency response was provided to affected Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners within 30 calendar days of approval.

M3. The Generator Owner shall have evidence it provided the Regional Reliability Organization and appropriate Transmission Planner and Planning Authority with verification and the status of its generator frequency response, consistent with the Regional Reliability Organization procedure.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

For Regional Reliability Organization: NERC.

For Generator Owner: Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

The Regional Reliability Organization shall retain both the current and previous version of the procedure.

The Generator Owner shall retain information from the most current and prior verification.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Regional Reliability Organization and Generator Owner shall each demonstrate compliance through self-~~-~~certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Regional Reliability Organization:

2.1. Level 1: Procedures did not meet either MOD-025 R1.1 or R1.3~~Method of verification of the generator frequency response was provided but was missing some of the information required in MOD-027 R2~~R1~~.2~~.

2.2. Level 2: Procedures did not meet requirement: MOD-025 R1.2~~Not applicable~~.

2.3. Level 3: The procedures were not provided as required by MOD-025 R2 or the procedures did not meet two of the following requirements: MOD-025-R1.1, R1.2. or R1.3~~Data on a how a unit is expected to change in response to frequency transients was provided but was missing some of the information required in MOD-027 R1.1~~.

~~2.4.~~**Level 4:** Procedures did not meet either MOD-025 R1.4.1 or R1.4.2~~There shall be a level four non-compliance if any of the following conditions are present:~~

~~2.4.1Information on speed/load governor controls was provided but was missing some of the information required in MOD-027 R2~~R1~~.1, or~~

~~2.4.2Method of the verification of the generator frequency response was not provided per MOD-027 R1.2, or~~

~~2.4.3Data on how a unit is expected to change in response to frequency transients was not provided, or~~

~~**2.4.4**~~**2.3.1** ~~Information on non-functioning or blocked speed/load governor controls, or controls that influence speed/load governor controls was not provided MOD-027 R1.3~~.

3. Levels of Non-Compliance for Generator Owner:

3.1. Level 1: There shall be a level one non-compliance if either of the following conditions is present:

Verified generator data was provided but was missing some of the information required in the method of verification required by regional procedure as specified in MOD-025 R1.4.2. ~~or~~

3.1.1

3.1.2 Any of the information required by regional procedure as specified in R1.4 did- not meet the regional periodicity and schedule of model and data verification and reporting

3.2. Level 2: Not applicable

3.3. Level 3: Not applicable

3.4. Level 4: There shall be a level four non-compliance if either of the following conditions ~~are~~is present:

3.4.1 Verified generator data was not provided.

3.4.2 Verified generator data was provided but was missing one or more Data characterizing how the unit speed and real power output are expected to change in response to initial and longer-term frequency deviations required by regional procedure and specified in MOD-025 R1.4.1. NOTE TO SDT – R1.4.1 REQUIRES UNSPECIFIED GENERAL DATA, THE REGIONAL PROCEDURE NEEDS TO SPECIFY A MINIMUM OF SUBJECT AREA OR DATA THAT ARE NEEDED SO WE CAN CHECK COMPLIANCE – NEED THIS STATED IN RRO REQUIREMENT

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

Commenter	Reliability Need	Acceptable Translation	Comments
IESO			(From Q 4 – Other comments) R1. We suggest changing the reference of MVAR as Mvar, as this is a SI abbreviation. R10.2 We suggest addition of a requirement/obligation for the Generator Operator to log information and times where they needed to run the generator to control power factor or reactive power.
Response: The drafting team will make the abbreviations~~.~~ consistent. The ~~drafting team can not determine a~~ reliability need for this addition in R10.2 is not clear.			
Carson Taylor – Bonneville Power Administration			As noted by IDWG, another standard is needed for automatic control of voltage and reactive power. Best practice is to rely primarily on automatic control, realizing that disturbances can evolve to blackouts within seconds or a few minutes—before operators can take action.
Response: Thank you for your comment. Please submit a SAR for the referenced proposed standard.			
Peter Burke – American Transmission Co.	Yes	No	We fully support moving R9.1 and R9.2 to VAR-002. V1 of this standard should be enhanced to include Measures that address all the Requirements R1--R12 comprising it. While the translation resulting in R3, R10, R11 and M1-M3 is acceptable, not fixing the pre-existing deficiencies (i.e. absence of any Measures) in the V0 standard makes the resulting VAR-001-1 an incomplete V1 revision.
Response: Thank you for your comment. ~~The drafting team notes this modification~~Modifying the standard to include measures for existing V0 requirements is outside the scope of the subject SAR.			
Greg Ludwicki – Northern Indiana Public Service Co.	Yes	No	Would like the vebiage to read either Generator Owner or Transmission Owner to supply this information. In our company, the Transmission Operator keeps the official records.

Response: The drafting team has considered your comment and believes the language in R10 requiring the TOP to provide procedures to the GOP allows the TOP to keep the records as long as the GOP provides the information in R10.2.			
Kansas City Power and Light	Yes	No	Added new requirements and revised several others. There is currently no standard that addresses voltage stability analysis and associated limits.
Response: The drafting team cannot respond to this comment due to insufficient information. Please submit a SAR for the referenced proposed standard.			
Mark Kuras – MAAC	Yes	No	All requirements are not dealt with in measures and levels of non-compliance.
Response: Modifying the standard~~The drafting team notes this modification~~ to include measures for existing V0 requirements is outside the scope of the subject SAR.			
Kenneth Dresner – FirstEnergy Solutions	Yes	No	The standard is well written but the 5 day time frame to respond to R5 is to short The number of transformers can amount to the hundreds and a response time of 30 business days seems more appropriate. Also the definition of Auxillary transformer needs to be clear. I believe that by merging of the standards will make the tracking of compliance more difficult. The issue of being noncompliant on one Requirement will roll up to the noncompliance to the overall standard This will make physically tracking the compliance levels more difficult
Response: ~~The drafting team believes the standard~~VAR-002 R5 was revised and now states the GOP has~~ already references~~ 30 calendar days to provide a response. The draft standard has been clarified to classify auxiliary transformers. The drafting team appreciates you comment.			
Xcel Energy – Northern States Power	Yes	No	Requirement R2 - "shall acquire" is a financial term, not a guidance term. Recommend change to "shall maintain".

			Requirement R5.1 - "shall notify the Generator Operator of a voltage schedule or reactive output " is not clear. Recommend change to " the Transmission Operator shall direct the Generator Operator to either maintain or change its voltage schedule or reactive output as necessary"
Response: ~~The drafting team notes items~~ R2 is from the original V0 approved standard and making modifications unrelated to the Phase III & IV measures is ~~therefore modification concerning "acquire" is~~ outside the scope of the subject SAR. The draft standard (now R6.1) ~~has been~~was modified based on your comments.			
Gred Mason – Dynergy Generation	Yes	No	1. Section B,R3-Suggest deleting reference to "reactive schedule"-a "voltage schedule" is the practical requirement that should be provided to the Generation Operator. 2. Section B,R3-Suggest clarifying that a voltage schedule is a range of voltage(not a specific voltage) and that voltage schedule should take into account voltage measuring accuracy and the dynamics of system voltage. The voltage schedule must also be a range of voltage(not a specific voltage) in order to comply with the R3 provisions of VAR-002-1. 3. We agree with moving R9.1 and R9.2 to VAR-002. 4. In Section B,R11 change the word "instructing" to "requiring"(consistent with the current standard). 5. There should be a "Requirement" added for the Transmission Operator to develop and provide a procedure to the Generator Operator regarding the R3 provisions of VAR-002.
Response: ~~The drafting team believes~~ R3. is written properly as it provides options to specify reactive needs to generators. There are TOPs who are providing GOPs with directions based on a reactive schedule. Either ~~The drafting team believes a~~a specific voltage with tolerances, or a voltage range ~~is~~ can be used for a voltage schedule. ~~so the drafting team believes no clarification of the term voltage schedule is required. The drafting team has moved~~ R9.1 and R9.2 were moved to VAR-002 as suggested. The draft standard has been modified based on your comments regarding "instructing". The standard has been modified to reflect this comment.			

IESO – Ontario	Yes	No	Questions are raised regarding the dropping of Generator Operators from this standard. It seems that there is a lot of responsibility placed on the Generator operators to notify the Transmission operators. Moreover, in addition to requirements laid down in section 9.1 & 9.2 of VAR-001 there are other requirments given in section R3 & R5 etc that necessitates the retention of Generator operator application in this standard. R2 should refer to Table 1 in TPL-001-0 to 004-0 for those contingency conditions that shall be considered.
Response: ~~The DT does not agree with the first comment, as~~ R3 and R5 ~~is~~ are primarily the responsibility of the TOP to provide to the GOP. The Generator Operator tasks were moved to VAR-002~~, 9.1 and 9.2 have been moved to VAR-002, so the Applicability to Generator Operators is not required~~. TPL-001 through TPL – 004 deal with long term planning, whereas R2 of this standard deals with the real – time near term operating horizon~~, therefore the DT does not agree with this comment~~. ~~The drafting team believes this beyond the intent R2.~~			
Brandon Snyder – Duke Energy	Yes	No	Requirement 6 is not a requirement. It is an understood entitlement of power. R11.2 should encompass entire standard. R5 should not contain all generators, the RRO should efine exemption criteria.
Response: The drafting team has reviewed R6 and realized it was a duplicate of R7. The drafting team still believes a requirement such as R7 is a necessary requirement for reliability. R11.2 was moved to become R3. as suggested so that it encompasses the entire standard. The drafting team has modified the standard to ~~reflect the comment on R5.~~ require the TOP to identify exemption criteria as suggested.			
Pacific Gas and Electric Richard Padilla Greg Reimers			R7 The basis for the requirement should be expanded "… to maintain system, interconnection, and nuclear power plant offsite power voltages within established limits."
Response: ~~The drafting team believes that m~~Maintenance of system voltages within established limits encompasses nuclear plant offsite power voltages therefore no expansion of R8 (previously R7) is required.			
Mohan Kondragunta –	Yes	No	SCE agrees with moving 9.1 and 9.2 to VAR-002-1

Southern California Edison			R10. In the WECC this requirement is handled through RMS and R10 would require new procedures are agreed to by Generators in the WECC. Change to read: "Each Transmission Operator, Balancing Authority or Reliability Authority with synchronous generation …"
Response: The drafting team has modified R9.1 and R9.2 as suggested. The drafting team, that has WECC members, believes this requirement does not conflict with the RMS. If SCE believes there is a conflict, the drafting team suggests SCE submit for a regional difference to the standard.			
SPP Transmission Working Group	Yes	No	No timeline for voltage schedules. R12 – no standard for NERC Votage Stability Analysis in associated limits.
Response: The drafting team does not have sufficient information to respond to the first comment. Please submit a SAR for the referenced proposed standard.			
Southern Company Generation	Yes	No	We believe the generator operator requirements R9, R10, and R11 should be deleted from VAR-001-1 and addressed separately from the Transmission by placing it in VAR-002-1 and reworded more appropriately.
Response: The DT does not agree with the first comment, as R10 and R11 ~~is~~are primarily the responsibility of the TOP ~~to provide to the GOP~~; the corresponding GOP requirements are included in VAR-002-1. ~~The~~ R~~r~~equirements R9.1 and 9.2 have been moved to VAR-002, so the ~~Applicability~~ applicability to Generator Operators is not required in VAR-001.			
Jerry Nicely – TVA Nuclear Generation SERC EC Generation Subcommittee (GS) D. Byran Guy – Progress Energy, Inc.	Yes Yes	No No	All generator operator requirements should be removed from VAR-001-1 and reconciled with the requirements in VAR-002-1. Strike the words and auxiliary from all sections of the standard.
Response: The drafting team ~~agrees and has made the revisions~~moved all GOP requirements to VAR-002 as suggested. ~~to the~~			

~~standard.~~ The drafting reviewed the use of “auxiliary” and ~~made modifications to the standard.~~modified the language to state, “…auxiliary transformers with primary voltages no less than the generator terminal voltage.”			
Tennessee Valley Authority	Yes	No	All generator operator requirements should be removed from this standard and reconciled with the requirements in VAR-002-1 and if not, then generator operators should be added in the Applicability Section. Strike the words “and auxiliary” from all sections. R4 mentions Marketers, but there is no mention in the Compliance section. R6 and R7 are redundant. Delete R6
Response: The drafting team ~~agrees and has made the revisions to the standard~~ moved all GOP requirements to VAR-002 as suggested. The drafting reviewed the use of “auxiliary” and modified the language to state, “…auxiliary transformers with primary voltages no less than the generator terminal voltage.” R4 is a requirement for the Purchasing-Selling Entity and was approved as a Version 0 Requirement –making modifications to already approved Version 0 Requirements that are not directly related to the Phase III & IV Measures ~~made modifications to the standard. The comment regarding R4~~ is outside of the scope of the current SAR. The drafting team ~~agrees and has made the revisions to the standard~~ modified the standard to remove R6 as suggested.~~.~~			
Resource Issues Subcommittee	Yes	No	1. R5 should allow for alternatives to the open-circuit step response test, such as on-line transient data collection methods. 2. RIS believes that consideration should be given in this standard to collecting the appropriate data to verify that units will perform as simulated. All of the information requested in R3 may not be necessary, and should not be required unless specified by the Region.
Response: The drafting team believes the RIS is referencing the wrong standard.			

NERC Interconnection Dynamics Working Group	Yes	No	1. Change the Title to: Operational Voltage and Reactive Control — 2. This standard appears to be aimed at the operator…a number of changes should be made to Standard VAR-003 to specifically address automatic voltage and reactive control from a planning perspective. — 3. Modify R.2 – Clarify what is meant by contingency conditions…R8 limits it to single contingencies, which are often not sufficient for analysis and operations. 4. ~~—~~R5.1 – Remove phrase: to maintain Interconnection and generator stability. 5. ~~—~~R5 – Add the terms …and availability… after the word status 6. — Reword R10.4 to read: Specify narrowly defined criteria by which generators are to be exempted from the above requirements, for example, to allow for temporary operating conditions. a. ~~—~~Having a general exemption clause weakens the standard and causes loopholes. 7. ~~-~~— R8 should be modified to read: …voltage under next contingency conditions… First appears to be a typo and appears to be confusing…the next contingency is the first contingency from the current operating condition.

Response:

1. The drafting team believes the title is appropriate because it has both operational and planning aspects.
2. Comments regarding VAR-003 should be addressed in the VAR-003 standard comments.
3. ~~The drafting team notes items~~ R2 is a requirement from the original V0 Standard and ~~approved therefore modification concerning~~ making the suggested modification is ~~clarification is~~ outside the scope of the subject SAR.
4. R5.1 (now R6.1) ~~has been~~was modified as suggested.
5. ~~The drafting team believes a~~Availability is included as part of status.
6. The drafting team moved R10.4 to become R3 and to apply to all the procedures addressed in VAR-001. The suggested

specific language wasn't adopted as it would be difficult to assess 'narrowly defined'. ~~has reviewed the exemption wording and has made a modification to the draft in response to comments.~~ 7. R8 is a requirement from the original V0 Standards and making the suggested modification is outside the scope of the subject ~~First contingency was part of the approved V0 standards and is therefore not part of the scope of this~~ SAR.			
Southern Company – Transmission	Yes	No	Revise R9.1. Each Generator Operator shall provide information to its Transmission Operator on the status of all generation reactive power resources, including the status of each voltage regulator and power system stabilizer, within 30 minutes or via real time SCADA as determined by the TO
Response: In response to the industry comment R9.1 will be moved to VAR-002-1. ~~The drafting team believes a~~Adding, 'via real time SCADA as determined by the TOP' does not enhance the requirement as SCADA signals should be received within 30 minutes and the TOP is directed to provide the GOP with a procedure as defined in R10. VAR-002-1 does include a 30-minute requirement.			
Joseph D Willson – PJM	Yes	No	1. Level 1 Only deals with reporting stuff and not with real-time operations. 2. Level 2 Only Requirement 10 talks about exemptions. 3. Level 3: unsure what is being measured. Is it any directive from the TO that is being measured versus real-time voltage/reactive? What amount of data are we talking about. 4. R3 needs to be re-written to state "Each TO shall specify a voltage schedule, voltage range, Reactive schedule, or reactive range for operations to be …" 5. The standard has many good requirements. However, the measures and therefore compliance levels 6. Any exemptions must be in the Regional Differences Section of the standard
Response: ~~Thank you for your comment, but the drafting team does not have sufficient information to respond.~~ 1. level one requires the TOP to have developed procedures for the GOP 2. Level two did reference both R10 and R3 –~~The drafting team has eliminated~~ R10.4 was eliminated and Level two now ~~and~~			

~~believes level two should~~ references R4.1 which does require the TOP to identify R4.1. Each Transmission Operator shall maintain a list of synchronous generators that are required to follow a voltage or reactive schedule and shall provide each Generator Operator with its voltage or reactive schedule. exemptions from ~~.~~. 3. The intent of Level 3 is to determine if the documentation was provided as required. ~~The drafting team believes a~~A specific voltage, a specific voltage with tolerances, or a voltage range ~~is~~ can all be used for a voltage schedule so ~~the drafting team believes~~ no clarification of the term voltage schedule is ~~required~~needed. 4. The individual procedures would include any specific exemptions to the individual Transmission Operator's requirements and would not necessarily be addressed at a regional level. ~~Thank you for your additional comments.~~			
Individual Members of CCMC	Yes	No	Level 1 Only deals with reporting documentation and not with real-time operations as required by much of the standard. Level 3: unsure what is being measured? Is it any directive from the TO that is being measured versus real-time voltage/reactive? What amount of data is required? This draft creates a standard made up from an incomplete V0 standard and 3 Phase 3 – 4 planning measurements. The result is confusing unless the original V0 requirements/measures/levels of non-compliance can be modified. It would be more complete and accurate if the proposed standard only merged Phase 3-4 planning measurements. R3 needs to be re-written to state "Each TO shall specify a voltage schedule, voltage range, Reactive schedule, or reactive range for operations to be …" The standard has many good requirements. However, the measures and therefore compliance levels need to reflect them. It may be more appropriate to include any exemptions in the Regional Differences Section of the standard..
Response: Thank you for your comment, but the drafting team does not have sufficient information to respond. The drafting team has eliminated R10.4 and believes level two should reference R4.1. The intent of Level 3 is to determine if the documentation was provided as required. The drafting team believes this comment regarding modification of the V0 standards is outside the scope of the subject SAR. The drafting team believes a specific voltage, a specific voltage with tolerances, or a voltage range is used for a voltage schedule so the drafting team believes no clarification of the term voltage schedule is required. The individual procedures would include any specific exemptions to the individual Transmission Operator's requirements and would not necessarily be			

addressed at a regional level. Thank you for your additional comments.			
PPL Corporation	Yes	Yes	PPL believes that a NERC standard should require all Generator Owners to have their Automatic Voltage Regulators (AVRs) in service and to immediately report any AVR outages to the system operator.
Response: ~~The drafting team based on other industry comments believes~~Agree,however exemptions to the AVR reporting requirements should be allowed.			
Karl Kohlrus - City Water, Light & Power	Yes	Yes	There should be a provision that AVR should be able to be turned off if the machine is operating at its limit. Prior to the August 14, 2003 blackout, Eastlake 5 was operating at maximum real and reactive output. Since it was in AVR mode, it tripped when it tried to produce even more VARs than it was capable of producing when the voltage declined further.
Response: Agree, exemptions to the AVR reporting requirements should be allowed.~~The drafting believes the standard as written is appropriate.~~			
WECC Reliability Subcommittee	Yes	Yes	WECC RS agrees with moving 9.1 and 9.2 to VAR-002-1
Response: Thank you. The drafting team has made the change based on industry support.			
Doug Hohbough – First Energy Corp.	Yes	Yes	Proposed move os sections to VAR-002-1 is ok.
Response: Thank you. The drafting team has made the change based on industry support.			
John Horakh – MACC	Yes	Yes	Ok to move R9.1 and R9.2 to VAR-002
Response: Thank you. The drafting team has made the change based on industry support.			
NPCC CP9 RSWG Alan Adamson -	Yes	Yes	R2 should refer to Table 1 in TPL-001-0 to 004-0 for those contingency conditions that shall be considered.

NYSRC	Yes	Yes	
Consolodated Edison	Yes	Yes	
Cinod Kotecha	Yes	Yes	
Kathleen Goodman – ISO-NE	Yes	Yes	
Response: TPL-001 through TPL – 004 deal with long term planning, whereas R2 of this standard deals with the real – time near term operating horizon.~~, therefore the DT does not agree with this comment.~~ ~~The drafting team believes this beyond the intent R2.~~			
Michael C. Calimano – NYISO	Yes	Yes	R2 should refer to Table 1 in TPL-001-0 to 004-0 for those contingency conditions that shall be considered. R3 should apply to all generators and not just synchronous generators. R9 NYISO recommends evaluating TOP-004-0 to determine if this requirement is captured within the IROL and SOL requirements. Consider incorporating the necessary language into the TOP-004 standard and deleting R9. R9.1 would be more appropriate as R10.1 R9.2 is addressed in VAR-002-1 and should removed. R11.2 does not have a valid purpose and should be removed from VAR-001-1. R12 should be in TOP-004 and be removed from VAR-001-1 There are requirements without measurements. All requirements should have measurements.
Response: TPL-001 through TPL – 004 deal with long term planning, whereas R2 of this standard deals with the real – time near term operating horizon. ~~, therefore the DT does not agree with this comment. The drafting team believes this beyond the intent R2. The drafting team does not agree with the comment concerning R3 as i~~Induction generators~~ion~~ generally cannot ~~generally~~ provide ~~VAr~~ VAR support, so they shouldn't be included in R3.. ~~The drafting team has made the change based on industry support.~~ The drafting team ~~has~~ evaluated TOP-004-0 and ~~has~~			

determined there is insufficient support to move R9 to TOP-004-0. The drafting team ~~has~~ moved R9.1 and R9.2 to VAR-002-1 as supported by ~~the~~ industry commenters. ~~The drafting team has modified the standard relative to~~ R11.2 was moved to become R3 and was revised to apply more broadly to require identification of exemptions from all the procedures addressed in this standard~~based on industry comments~~. The drafting team does not believe the industry supports the movement of R12 to TOP-004-0. ~~The drafting team notes this modification to include~~ Adding measures for existing V0 requirements is outside the scope of the subject SAR.			
FRCC	Yes	Yes	Need to define voltage or reactive schedule and use consistently in the standard. Delete R9.1 and R9.2 and re-word R5 to include clearly defined requirements of the Transmission Operators and Generator Operators. Generator Operators should be required to determine the reactive setpoint required to maintain generator stability, not Transmission Operators. Clearly delineate the responsibilities for interconnection stability (Transmission Operator) and generator stability (Generator Operator). R3, R10 and R11 need to be re-written to clarify the intended requirements.
Response: The drafting team believes a specific voltage, a specific voltage with tolerances, or a voltage range is used for a voltage schedule so the drafting team believes no definition of the term voltage schedule is required. The drafting team believes it has applied voltage and reactive schedule consistently throughout the standard. The drafting team has moved R9.1 and R9.2 to VAR-002-1 as supported by the industry. ~~The comment concerning~~ R5 deals with ~~the portion that is~~ an approved V0 requirement ~~standard~~ and ~~therefore~~ modification is not within the scope of this SAR. The drafting team believes the TOP determines the setpoint within the parameters of the specific machine. The drafting has modified the R10 and R11 based on industry comments, R3 was not modified as it was part of the approved V0.			
Gerald Rheault – Manitoba Hydro	Yes	Yes	This standard should apply to all generators, not just synchronous generators. R2: How does one measure if reactive resources are sufficient? Also, clarify contingency conditions- Cat B, C & D?

			R8: requires reactive resources to support voltage under first contingency. Does this conflict with R2? The wording in R3 should be modified so it is not mandatory for each generator to have a voltage schedule. For vertically integrated utilities the process of managing voltage and reactive control may be performed in a way such that a voltage schedule for each generator is not actually produced and communicated through a formal process which should be acceptable.
Response: ~~The drafting team does not agree with the comment concerning R3 as i~~Induction generatorsion generally cannot ~~generally~~ provide ~~VAr~~ VAR support. The drafting team believes the comment concerning R2 is included in VAR-003-1. ~~Clarification of contingency conditions and modification of R8 or R2 is outside the scope of this SAR because~~ R2 and R8 are existing V0 Requirements and modifying these is outside the scope of the SAR. ~~The DT believes that t~~The Standard ~~contains language~~ was revised to add language that requires the TOP to identify exemption criteria for all of the procedures addressed in this standard, and this includes the procedure the requires the generator to have ~~allows for generator to be exempt from a requirement to have~~ a voltage schedule.			
Midwest Reliability Organization	Yes	Yes	Move VAR-001-1 R9.1 and R9.2 to VAR-002 R1.1 and R1.2 so that all Generator Owner requirements are together. D2.2.2 and D2.2.3 can "incomplete" be defined as a measurable quantity? In R3, after "Each Transmission Operator shall", add the words "maintain a list of synchronous generators that are required to follow a voltage schedule, and". It should not be mandated that every unit have a voltage schedule developed for it. Also, this allows for the deletion of R3.1, which then becomes redundant. Note that without any change, R3 seems to indicate all generators must have a voltage schedule, while R3.1 seems to indicate only some need a schedule. Add a M4 that reads "In the event a voltage collapse occurs, the Purchasing-Selling Entity or Transmission Operator shall, within 30 calendar days of a request, provide documents to the Regional Reliability Organization and NERC demonstrating the actions it took under R2 (TO), R4 (PSE), R6 (TO), R8 (TO), and R12 (TO) to prevent the voltage collapse." Corresponding language

			should also be added under Level 4 of the Non Compliance language.
Response: The drafting team ~~has~~ moved R9.1 and R9.2 to VAR-002-1 as supported by the industry. The expectation for being in compliance would be 100% information anything less would be incomplete. The Standard was revised to add language that requires the TOP to identify exemption criteria for all of the procedures addressed in this standard, and this includes the procedure the requires the generator to have a voltage schedule. ~~The DT believes that the Standard contains language that allows for generator to be exempt from a requirement to have a voltage schedule.~~ The ~~drafting team notes this~~suggested addition of M4 and associated non-compliance is ~~modification to include measures for existing V0 requirements is outside the scope of~~ outside the subject SAR because it would be a measure for a Version 0 Requirement.~~.~~			
Rebecca Berdahll – Bonneville Power Administration Karl Bryan – Corp of Engineers Jay Sietz – US Bureau of Reclamation Brenda Anderson	Yes	Yes	Within WECC the requirements of R10 have been communicated to the generation owners via the RMS. Provide additional clarity to R4 to avoid possible misinterpretations of this requirement. Is the Transmission Provider to provide the reactive quantity to the PSE for each transaction? What PSE documentation is NERC requiring to document this requirement has been met? The applicability statement does not include the Transmission Provider.
Response: Thank you for the comment on RMS. The drafting team notes that modification to R4 would be a change to an approved portion of a V0 requirement and is outside the scope of the subject SAR. The comment regarding the transmission provider and PSE is not within the scope of this SAR.			
Deborah M. Linke – US Bureau of Reclamation	Yes	Yes	Within WECC the requirements of R10 have been communicated to the generation owners via the RMS.
Response: Thank you for the comment on RMS.			
SERC EC Planning	Yes	Yes	Suggest that R6 be deleted since all the R6 requirements are included in R7.

Standards Subcommittee (PSS) Entergy John K. Loftis, Jr. – Dominion – Electric Transmission	 Yes Yes	 Yes Yes	The PSS agrees with moving R9/1 and R9/2 to VAR-002.
Response: The drafting team ~~has modified the standard based on industry support..~~deleted R6 as suggested.			
Raj Rana – AEP	Yes	Yes	Change the title to Real Time Voltage and Reactive Control. This is to reflect the focus of this standard, which is in the transmission operations arena. Reword R8 as follows: Each Transmission Operator shall maintain reactive resources to support its voltage under credible contingency conditions. (This allows looking at n-1 as well as multiple contingencies.)
Response: The drafting team believes the title is appropriate because it has both operational and planning aspects. ~~The drafting team notes that modification to~~ R8 is an existing V0 requirement and making modifications to V0 requirements that aren't related to the measures in Phase III & IV is ~~would be a change to an approved portion of a V0 requirement and is~~ outside the scope of the subject SAR.			
Transmission Issues Subcommittee	Yes	Yes	R2 should clarify that the Contingency conditions are those contingencies described in Table 1 of NERC standards TPL-001, 002, 003, and 004. "synchronous" should be removed and R3 should apply to all generators. R8 only refers to first contingencies. The drafting team should confirm whether that is the intent of this Requirement. R12 should provide guidance to the TO on anticipating contingencies, such as Category D from Table 1 of the TPL standards, that could lead to voltage collapse.
Response: The drafting team notes that modification to R2, R8, and R12 would be a change to an approved portion of a V0 requirement and is outside the scope of the subject SAR. In addition, the contingencies in Table 1 are intended for use in the			

planning horizon, not in the operating horizon. ~~The drafting team does not agree with the comment concerning R3 as i~~Induction generators generally ~~ion~~ cannot ~~generally~~ provide ~~VAr~~ VAR support, so R3 was not modified. R8 and R12 are existing V0 requirements and making modifications to V0 requirements that aren't related to the measures in Phase III & IV is outside the scope of the subject SAR.			
Transmission Subcommittee			1. VAR-001-1, A. Introduction, 4. Applicability, TS recommends adding "4.3. Transmission Service Provider" - TS: TSP is used in R4. 2. VAR-001-1, R3, TS recommends adding language for technical accuracy as follows: Each Transmission Operator shall "maintain a list of synchronous generators and shall (add)" specify a voltage or reactive schedule . . . TS recommends deleting R3.1, with additional language inserted into R3 3. VAR-001-1, R8.1., TS recommends the following language change: Each Transmission Operator "disperse and locate (delete)" "direct the operation of (add)" of reactive resources so that . . . 4. VAR-001-1, R9., TS recommends evaluating TOP-004-0 to determne if this requirement is captured within the IROL and SOL requirements. Consider incorporating the necessary language into the TOP-004 standard and deleting R9. 5. VAR-001-1, R9.1, TS recommends moving R9.1 to R10.1, since it is more appropriate under R10. 6. VAR-001-1, R9.2, TS recommends deleting R9.2, since it is essentially captured in VAR-002-1. 7. VAR-001-1, R11.2, TS Comment: R11.2 doesn't seem to have a valid puirpose. R11.2 should either be deleted, or language should be added to clarify its purpose/intent. 8. VAR-001-1, R12, TS recommends evaluating TOP-004-0 to determine if this requirement is captured within the IROL and SOL requirements. Consider incorporating the necessary language into the TOP-004 standard and deleting R12.

			9. TS Observation: There are requirements that do not have measures. The TS was under the impression that all requirements needed to have measures to meet the criteria of the Standards Process Manual. 10. VAR-001-1, M4, TS Recommendation and Consideration: TS Recommends adding M4 as follows: "M4. In the event a voltage collapse occurred on the bulk electrical system under the control of the Transmission Operator during the performance period, the Transmission Operator shall produce documents, within 7 calendar days, demonstrating the actions it took under VAR-001-1, R2, R6, R8, and R12, in an effort to prevent the voltage collapse." 11. VAR-001-1, M4, TS Consideration: TS recommends evaluating Measure M4 for inclusion within TOP-004, and remove the measure from this standard. 12. VAR-001-1, D. Compliance, 2.4., Level 4: TS recommends adding the following second paragraph to VAR-001-1, 2.4., "In the event a voltage collapse occu8rs, if the Transmission Operator has inadequate documentation demonstrating it took proper preventative actions under VAR-001-1, R2, R6, R8, and R12." 13. VAR-001-1, Compliance, 2.4., Level 4, TS Consideration: TS recommends evaluating Compliance Level 4 language for inclusion within TOP-04 and remove the Level 4 language from this standard.

Response:

The drafting team notes that modification to the Applicability section would be a change to an approved portion (R4) of a V0 requirement and is outside the scope of the subject SAR. Note that in R4, the TSP's actions are not a requirement for the TSP.

The DT reviewed this comment and believes that R3 and R3.1 are acceptable as written. (There was minimal support for this change from the industry.)

~~The drafting team notes that m~~Modifying existing Version 0 requirements (R8, R9, R12) Measures (M4) and levels of non-compliance or adding measures and non-compliance for Version 0 requirements that are unrelated to the measures in Phase III & IV is ~~odification to R8, R9, R12, and changes to Compliance 2.4 Level 4 would be a change to an approved portion of a V0 requirement and is~~ outside the scope of the subject SAR.

In response to this and other industry comments, the DT ~~has~~ revised this standard and moved R9.1 and R9.2 to VAR-002-1. R11.2 was moved to become R3. as suggested so that it encompasses the entire standard. ~~The drafting team has modified the standard relative to R11.2 based on industry comments.~~ ~~The drafting team notes this modification to include measures for existing V0 requirements (including the suggested M4) is outside the scope of the subject SAR.~~			
Joseph F. Buch – Madison Gas and Electric	Yes		
Samuel W. Leach – TXU Power	Yes	Yes	
Ed Riley – California ISO	Yes	Yes	
ISO/RTO Council Standards Review Committee	Yes	Yes	
Ronnie Frizzell - Arkansas Electric Coop. Corp.	Yes	Yes	
Dan Griffiths – PA Office of Consumer Advocate	Yes	Yes	
Howard Rulf - WE Energies	Yes	yes	

Les Pereira P.E.

General Comments Related to VAR-001-1, VAR-002-1, VAR-003-1 Standards

The VAR series of NERC Standards: VAR-001-1, VAR-002-1, VAR-003-1 on Voltage and Reactive Control, Generation Operation and Planning Assessment are one of the most important of the NERC Standards and touch upon one of the most difficult topics in system planning and operation today, namely to ensure that system reactive resources are "adequate" or "sufficient" to plan and operate the system so that voltage stability is ensured.

The three standards collectively have failed to :

1. Properly recognize, define and quantify "adequate" or "sufficient" reactive resources;
2. Describe how these are measurable in real-time and so indicated to the operator;
3. Differentiate the special requirements for "emergency" operation that require special approaches in real-time versus "normal" states of the system.
4. Make it clear what are the precise roles of the various entities: Transmission Operators/Purchasing-Selling Entities, Generator Operators and Transmission Planner/Planning Authority to ensure supply of adequate reactive resources, particularly during emergencies.

Given the importance of voltage control and reactive reserves and the role it played in the last three major blackouts : the July and August 1996 blackouts in the Western Interconnection and the August 2003 blackout in the Eastern Interconnection, it behooves NERC to seriously examine the adequacy of its VAR standards in addressing a difficult and contentious issue. Numerous smaller events also illustrate the effects on reliability of MVAR deficiency on a smaller scale than the larger blackouts. Indeed the rules and approaches in recognizing the importance and difficulty of reactive power assessment and supply need to be reassessed. FERC has recognized this, has taken the lead, and issued a comprehensive report which is the best first step in addressing the real MVAR requirements that the system needs to have to operate reliably and efficiently and the need for the industry/market to realize its importance. Now it is NERC's turn to likewise recognize the crucial role of voltage control and reactive power for voltage stability and include special requirements in NERC Standards. (The term MVAR is used in these comments to mean 'reactive power').

Emergency Conditions need Special Requirements

The proposed draft of NERC Standards VAR-001-1, 002-1, and 003-1 essentially describe basic "good utility" practices that are applicable and generally work well when operational conditions are "normal" including regular N-1 contingencies. These requirements are such that any Transmission Operators/Purchasing-Selling Entities, Generator Operators, and Transmission Planner/Planning Authority could meet under those conditions. The standards require that: "Each Transmission Operator shall acquire "sufficient" reactive resources within its area to ensure "adequate" voltage levels under normal and Contingency conditions." (From R2 of VAR-01-1, quotation marks added). When a blackout occurs, the involved entities can take refuge in the lack of specificity of the standards to defend their case. Adding the words "and if necessary load shedding" does not make the standard any stronger, because the necessary specificity to the operator to determine the circumstances when to resort to load shedding is not provided. Load shedding decisions cannot be taken lightly. If delayed too long, conditions could lead to blackouts. If done too early, the operator will face the inevitable recriminations and pay for potential liabilities. Hence the Standards should have special provisions for operation in emergency conditions. This is explored further later.

Dynamic vs. Static Reactive Power Sources Must be Recognized in the Standards

Static reactive power is supplied by static devices such as shunt or series capacitors, and the capacitance of the lines. Dynamic reactive power is supplied by dynamic machines such as synchronous generators or condensers. Static var compensators because of automatic controls are also classified as 'dynamic'.

The factors of location, MVAR quantity, quality i.e. static or dynamic, and the time, season, and system operating conditions, all directly affect the 'adequacy' and 'effectiveness' of reactive power reserves.

Shunt capacitors are a cheap source of MVAR supply. It works well when voltages are normal. However, the quantity of MVARs supplied by shunt capacitors is directly proportional to the square of the voltage. Hence as the voltage plunges, so does the effectiveness of shunt capacitors. Eg at 90% voltage, the shunt capacitor will put out only 81% of the rated MVARs. This becomes more and more critical as loads peak and voltages deteriorate in voltage instability prone areas during emergency condiitons. As line flows increase, MVAR flow through lines increase as voltages decrease and MW losses increase. This gets worse as key lines or generators trip in the MW and/or MVAR deficient area. The end comes usually suddenly as voltage drops (at 80% voltage, the shunt capacitor MVARs is just 64% of rated) and may likely be controlled only by load-shedding.

The <u>total of the static and dynamic capability</u> should exceed the total MVARs 'absorbed' by the load and the lines and transformers in the area of concern <u>by an 'adequate' margin (also called the reserves)</u>. The 'margin' computation is made for a variety of contingencies. The difficulty is in exactly computing what the 'reserves' should be and what the static and dynamic parts should be that will be 'adequate' for various operating conditions. The split between the required Dynamic and Static MVARs has to be computed on a case by case basis for critical areas. Several empirical methods exist to determine this split, but have proved inadequate during post-mortem studies of blackouts.

There are analytical methods and tools to determine reactive power MVAR reserves. Static methods use computations that provide MW Power-Voltage and MVAR-Voltage curves (also known as PV and QV curves). Dynamic methods use stability programs with special provisions for long runs (minutes rather than seconds). These VAR Standards *do not even mention dynamic and static VARS* or these analytical tools.

<u>Locational Decisions and Identifying Potential Voltage Instability Areas</u>

MW power is transmitted from generators to loads through the transmission network. The network voltages must be maintained by MVAR supply for power to flow. As loads increase, flows through the lines increase, voltages decrease and MW and MVAR losses increase. This gets worse as key lines or generators trip in the general area. (When this gets into an uncontrollable repetitive cycle, we have 'voltage instability' as voltages collapse). To support voltage in an area, the reactive power is best supplied close to where the system voltage sags are the greatest, or where a reactive power 'deficiency' has been identified. Transmission Operators should be required by the standards to identify all potential voltage instability areas, determine the critical buses and the potential contingencies that could lead to voltage instability. This may not cover all conditions but will narrow the list to critical ones. Operating instructions should identify optimum location(s) and the amount of MVAR needed to maintain voltages for a variety of contingencies and operating conditions.

It should be noted that the power system is a continually growing dynamic system in terms of loads, and generators. Many areas have experienced problems as generators retire and are not replaced by new generation, or are replaced by cheap, remotely located generation supply.

<u>Planning Vs Operation Scenarios</u>

In the planning standards similarly, it should be required to identify all potential voltage instability areas and the optimum location(s) and the amount of MVAR needed to maintain voltages for a variety of contingencies and operating conditions. The answers may be quite different in planning studies which may show adequate MVAR reserves in generators. But in a real-time operation situation where generators are bid into the market on a MW basis only, the numbers may be quite different. The MVAR 'capability' may well exist in remote generators, but this is different from the actual 'local capability' that is required as system conditions get worse.

Voltage Control Schedules are Usually Prepared Ahead of Time– How Applicable are they in Real-Time?

Questions arise on how good is the Voltage Schedule as it relates to real-time if it is prepared ahead of time. Wouldn't the system conditions dictate what the schedule is in real-time? How will a-100 generators be notified to change their voltage settings if suddenly severe contingencies occur that upsets planned schedules?

Voltage schedules relate to operation practices and are set by operation-planning studies that result in a 'voltage profile' that should be maintained. These schedules generally follow the general directions of flow from generation 'areas' to load 'areas'. (For e.g. in WECC, the Northwest would have voltages at 110% and the southern buses in California would have voltages close to 100 %.) The Interconnection however is comprised of many control areas which may have different policies in maintaining its required 'voltage profile. Standards should require that they coordinate with other control areas or regions because in real-time, physics ignores man-made borders. Blackout investigations often show that conditions outside sometimes influence the outcome inside the area. Real-time operation has additional road blocks as seams issues make it impossible to view conditions outside the control areas. Standards should encourage a wider view of the system and the possibility of sharing data across systems.

Generator AVRs required to maintain a specified voltage setting

Ensuring a required set-point voltage on generator AVRs is the best way to ensure that voltages will be maintained at the generators – and hence at the EHV bus. Operation during emergency conditions should be specified. Automatic over-excitation and under-excitation limiters in generator AVRs ensure that MVAR limits are not exceeded during operation. The practice of power factor control must be discontinued for generators which must be under continuous automatic voltage control.

The primary function of the generator AVR (Automatic Voltage Regulator) is to regulate generator voltage for the exciter to supply MVARs. Other features available in AVRs allow for 'reactive current compensation' or regulation that takes into account the generator-transformer impedance, or to allow MVAR sharing of many generators in the plant. 'Joint control' of many generators can set the voltage at the HV side as the reference, but will ensure that each unit provides MVARs in proportion to its capability curve.

Difficulties to the Operator in Recognizing Impending Voltage Collapse

Studies of the 1996 blackouts in the Western Interconnection showed that the MVARs supply from the system shunt caps fell off rapidly towards the end, and generators were not able to supply required MVARs made worse by generator tripping in critical areas. Operators had difficulty in recognizing that a collapse was imminent on July 2, 1996 from observing the voltages on their voltmeters because recordings showed that the voltages held up well until the last 30 seconds. Holding up voltages till the last is a characteristic of shunt capacitors. The quantity of MVARs supplied by shunt capacitors is directly proportional to the square of the voltage, hence as the voltage plunges, so does the effectiveness of shunt capacitors. In general, the effect of non-availability of reactive power is non-linear in nature as seen in MW Power-Voltage and MVAR-Voltage (PV and QV) curves and is difficult to predict.

The conclusion is that standards should not emphasize only adequate voltage profiles as a requirement without mentioning the very necessary dynamic reactive power to avoid voltage collapse and a measurement to its adequacy.

Difficulty in Real-Time Measurement of 'Adequate' Reactive Reserves.

If the static PV-QV calculations state that there should be for e.g. 500 MVARs of reserves at a specific 500 kV bus, the difficulty is to measure it practically whether such an 'adequate' reserve is actually available at that bus.

Measurement is therefore practically related currently to whether generators plus capacitors plus SVDs in an 'area' cumulatively have adequate MVAR reserves. The area will need to be 'bounded' for such a definition to work.

The conclusion is that a 'theoretical' calculation is possible, but a practical measurement or quantification of 'adequate' reserves in real-time *at a* *bus* is impractical. The best approach that the industry has at present is to calculate in real-time through state-estimated solutions and ensure 'adequate' reactive reserves are available in operation for critical areas during emergencies.

An Important Topic not touched upon in the NERC Standards – Reliability and Optimal System Operation

The Security Constrained Optimal Power Flow (SCOPF) program is the best tool there is today that integrates economics, generation dispatch and transmission power flows considering the reactive power and voltage constraints of the system. Unfortunately, currently most ISO market systems, except for the NYISO (and a future CAISO), that run LMPs (Locational Marginal Prices), use only DC SCOPF Programs in dispatching generators that do not consider reactive power and voltage constraints of the system. DC SCOPF programs assume that voltages are equal to 1.00 pu at all buses. Hence units will always be dispatched optimally for MW only. This is understandable because the market currently focuses on MW and not MVAR.

It is therefore very advantageous that AC Security Constrained Optimal Power Flow (SCOPF) Programs be used instead of DC SCOPF programs by Market Systems in dispatching generators in order to include reactive power and voltage constraints of the system.

Whether the new Standards should recognize these issues in market systems and make it possible to integrate optimal dispatch of MW and voltage control/reactive power dispatch of MVARS will be likely opposed strongly by those who use DC OPF programs. But this is an opportunity to get things right and efforts should be made in that direction.

Conclusions and Recommendations

A new SAR is required to address the many points raised in these comments. It is clear that the VAR series of NERC Standards: VAR-001-1, VAR-002-1, VAR-003-1 on Voltage and Reactive Control, Generation Operation and Planning Assessment do not address the critical and practical requirements of voltage control and reactive power under emergency conditions.

These standards must address voltage instability, arguably the most difficult phenomena in systems operation today. These important NERC Standards to ensure that system reactive resources are "adequate" or "sufficient" to plan and operate the system so that voltage stability is ensured should therefore not have imprecise or vague requirements.

Response: Thank you for your comment. The DT supports the submission of a SAR as described in your conclusions and recommendations.

A. Introduction

1. **Title:** **Voltage and Reactive Control**
2. **Number:** VAR-001-~~0~~1
3. **Purpose:**

   To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in real time to protect equipment and the reliable operation of the Interconnection.

4. **Applicability:**

   4.1. Transmission Operators.

   ~~4.2.Generator Operators~~

   ~~4.3.~~4.2. Purchasing-Selling Entities

5. **Proposed Effective Date:** ~~April 1, 2005~~January 1, 2007

B. Requirements

~~R1.~~Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and MVAR flows within their individual areas and with the areas of neighboring Transmission Operators.

R1.

~~R2.~~Each Transmission Operator shall acquire sufficient reactive resources within its area to ~~protect the~~ensure adequate voltage levels under normal and Contingency conditions. This includes the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.

R2.

R3. The Transmission Operator shall specify exemption criteria for generating units in the development of procedure as defined in VAR-001 R4, R6, R11, and R12 (including any that may apply to nuclear units)

R4. Each Transmission Operator shall specify a voltage or reactive schedule to be maintained by each synchronous generator, within the reactive capability of the unit, at a specified bus and shall provide this information to the Generator Operator.

R4.1. Each Transmission Operator shall maintain a list of synchronous generators that are required to follow a voltage or reactive schedule and shall provide each Generator Operator with its voltage or reactive schedule.

R4.2. Each Transmission Operator shall develop a procedure for communicating to the Transmission Operator failure to maintain a voltage or reactive schedule by a Generator Operator in accordance with VAR-002 Requirement 3.

R4.3. Upon notification by the Generator Operator of a voltage schedule deviation, the Transmission Operator will log such notification.

R5. Each Purchasing-Selling Entity shall arrange for (self-provide or purchase) reactive resources to satisfy its reactive requirements identified by its Transmission Service Provider.

R6. The Transmission Operator shall know the status of all transmission ~~reactive power~~Reactive Power resources, and develop procedures to be given to the Generator Operator on communicating ~~including~~ the status. ~~of voltage regulators and power system stabilizers.~~

~~R6.~~When notified of the loss of an automatic voltage regulator control, the Transmission Operator shall direct the Generator Operator to either maintain or change its voltage schedule or Reactive Power schedule as necessary.

R6.1.

~~The Transmission Operator shall be able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow.~~

Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – including reactive generation scheduling; transmission line and reactive resource switching; and, if necessary, load shedding – to maintain system and Interconnection voltages, and reactive flows within established limits.

R7.

~~R7.~~Each Transmission Operator shall maintain reactive resources to support its voltage under first Contingency conditions.

R8.

~~R7.1.~~Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when Contingencies occur.

R8.1.

Each Transmission Operator shall correct IROL or SOL violations resulting from reactive resource deficiencies (IROL violations must be corrected within 30 minutes) and complete the required IROL or SOL violation reporting.

R9.

R10. Each Transmission Operator with synchronous generation connected to its system shall provide to the Generator Operator procedures that shall:

R10.1. Require the Generator Operator to provide summary reports showing the number of hours each synchronous generator did not operate in the automatic voltage control mode during a specified time period.

R10.2. Require the Generator Operator to provide logs containing the date, duration, and reason for each period when a synchronous generator was not operated in the automatic voltage control mode.

R10.3. Require the Generator Operator to retain the above information for 12 rolling months.

R11. The Transmission Operator shall have, and shall provide to the Generator Operator, procedures requiring Generator Operators to provide tap settings, available tap ranges, and impedance data for generator step-up and where applicable, auxiliary transformers with primary voltages no less than the generator terminal voltage.

R11.1. When mutually agreed to tap changes are necessary, the Transmission Operator shall provide documentation to the Generator Operator specifying the required tap changes and technical justification for these changes.

~~Each Generator Operator shall provide information to its Transmission Operator on the status of all generation reactive power resources, including the status of voltage regulators and power system stabilizers.~~

~~R9.1.When a generator's voltage regulator is out of service, the Generator Operator shall maintain the generator field excitation at a level to maintain Interconnection and generator stability.~~

R12. The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.

C. Measures

M1. For Reliability Standard VAR-001-1 R4., the Transmission Operator shall have documentation of the voltage or reactive schedule provided to the Generator Operator, as well as, any deviations logged and shall provide the information to the Regional Reliability Organization and NERC within 30 calendar days of a request.

M2. The Transmission Operator shall have evidence that the written procedures for synchronous generators meet Requirement 10 and shall provide the information to the Regional Reliability Organization and NERC within 30 calendar days of a request.

M3. The Transmission Operator shall have procedures for reporting synchronous generator step-up and auxiliary transformer tap settings and available tap ranges as specified in Requirement 11 and shall provide the information to the Regional Reliability Organization and NERC within 30 calendar days of a request.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year

1.3. Data Retention

The Transmission Operator shall retain current and previous version documentation.

1.4. Additional Compliance Information

The Transmission Operator shall demonstrate compliance through self certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. **Level 1:** Transmission Operator has procedures for Generator Operators to follow but they do not include all aspects of Requirements R10 or R11.

2.2. **Level 2:** Incomplete list of exempt synchronous generators was provided per requirement R4.1.

2.3. **Level 3:** Incomplete documentation of the requested voltage or reactive schedule was provided per requirement R4.

~~2.4.~~**Level 4:** Transmission Operator has no documentation or procedures addressing requirements R3, R10, or R11.

2.4.

~~**Not specified.**~~

~~**D.Compliance**~~
~~Not specified.~~

D. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

<table>
<tr><th>Commenter</th><th>Reliability Need</th><th>Acceptable Translation</th><th>Comments</th></tr>
<tr><td>Barry Green – Ontario Power Generation</td><td></td><td></td><td>(From Q 4 – Other comments)
The definition of the levels of non-compliance are based on the accumulated numbers of "unithours" of operation out of compliance. Such a measure does not take account of the fact that not all units are equally impactive. Being out of compliance for a small hydroelectric unit is not equivalent, in terms of system impact, to being out of compliance for a large fossil or nuclear station.</td></tr>
<tr><td colspan="4">Response: The ~~drafting team believes the~~ exemption criteria delineated in VAR-001-1 will address the concern of relative impact.</td></tr>
<tr><td>Gred Mason – Dynergy Generation</td><td></td><td></td><td>(From Q 4 – Other comments)
Requirement R1.1 of VAR-002-1 seems redundant to Requirement R14 of TOP-002-0.Suggest deleting R1.1 from VAR-002-01.</td></tr>
<tr><td colspan="4">Response: The drafting agrees the language is somewhat redundant but will modify R14 of TOP-002 because the VAR-002-1 is more comprehensive and requirements should only reside in one standard.</td></tr>
<tr><td>Les Pereira P.E.</td><td></td><td></td><td>Please see VAR-001-1</td></tr>
<tr><td colspan="4">Response: Please see response to VAR-001-1</td></tr>
<tr><td>Kansas City Power and Light</td><td>Yes</td><td>No</td><td>It appears this standard is redundant with TOP-002, TOP-003, IRO-005</td></tr>
<tr><td colspan="4">Response: The drafting agrees the language is somewhat redundant but will modify R14 of TOP-002 because the VAR-002-1 is more comprehensive and requirements should only reside in one standard. The drafting team does not find redundancies with TOP-003 which includes requirements for coordination of outages or IRO-005~~.~~ which addresses the RC's requirements for monitoring and directing control of its RC Area to stay within defined limits. There are requirements in IRO-005 for the RC to direct the GOP to make operating changes to return to within defined limits, but there are no requirements in IRO-005 for the Generator Operator.</td></tr>
<tr><td>Deborah M. Linke – US Bureau of</td><td>Yes</td><td>No</td><td>We agree the generation owner will maintain the voltage schedule provided by the transmision operator within the capability of the generator; however in</td></tr>
</table>

Reclamation Rebecca Berdahll – Bonneville Power Administration Karl Bryan – Corp of Engineers Jay Sietz – US Bureau of Reclamation Brenda Anderson	Yes	No	practicality the transmission operator monitors the voltage levels with the appropriate instrumentation (that may not even be available to the generator owner). As such they are the logical entity to log instances in which a voltage schedule was not met. The standard does not define what voltage level constitutes a deviation from the schedule, +/-1% ?
Response: ~~The drafting team believes the v~~Voltage is either directly or through inference monitored by both the GOP and the TOP. ~~The drafting team also believes b~~Both the GOP and TOP should log when a voltage schedule deviation occurs and ~~has~~ the drafting team ~~modified VAR-001-1~~ added this task to the TOP's list of requirements in VAR-001.~~accordingly.~~ ~~The drafting team believes a~~Any deviation beyond the schedule (plus or minus any range or bandwidth) is a deviation from schedule.			
Kenneth Dresner – FirstEnergy Solutions		No	The standard is well written but the 5 day time frame to respond to R5 is to short The number of transformers can amount to the hundreds and a response time of 30 business days seems more appropriate. Also the definition of Auxillary transformer needs to be clear. I believe that by merging of the standards will make the tracking of compliance more difficult. The issue of being noncompliant on one Requirement will roll up to the noncompliance to the overall standard This will make physically tracking the compliance levels more difficult
Response: VAR-002 R5 was revised and now states the GOP has 30 calendar days to provide a response. ~~The drafting team has made the change to standard based on industry support. The drafting team believes the standard already references 30 days.~~ The draft standard was ~~has been clarified~~modified as follows to ~~classify~~ identify more specifically the subset of auxiliary transformers that are addressed in requirement R5:			

– auxiliary transformers with primary voltages no less than the generator terminal voltage.			
Greg Ludwicki – Northern Indiana Public Service Co.	Yes	No	Would like the vebiage to read either Generator Owner or Transmission Owner to supply this information. In our company, the Transmission Operator keeps the official records. B. R1. R1.1 and R1.2 We concur these R9.1 and R9.2 should be moved to VAR-002. B. R1. R1.2 Proposed adding "automatic" between Generator's and voltage. R4 &R5:Does this include load as well as non-load tap changers. Is this referring to older voltage regulator systems (load tap changers) that may just change taps to control the generator voltage? D.2. 2.4.2 The non-compliance for not changing the tap (settings) as requested should also include not changing the generator voltage to maintain the system voltage (R2). This is the main intent of this Standard.
Response: The drafting team has considered your comment and believes the language in R10 requiring the TOP to provide procedures to the GOP allows the TOP to keep the records as long as the GOP provides the information in R10.2. ~~Thank you for your comment.~~ Most commenters agreed with moving R9.1 and R9.2 to VAR-002 and the drafting team made this modification. The ~~drafting team agrees and has made this change to~~word, 'automatic' was added as suggested.~~ AVR~~ ~~.~~ The drafting team has made the changes to R4 and R5. ~~The drafting team believes the final comment is addressed in a~~All four levels of compliance include sanctions for operating off the voltage or reactive schedule or operation without automatic voltage control for various time periods.~~.~~			

Gred Mason – Dynergy Generation	Yes	No	1. In Sections B,R1.1 and BR3 what is the basis for 30 minutes? A specific timeframe is not in the current standard. Suggest using the wording from TOP-002-0 which provides for notification "without any intentional time dealay."If this requirement is retained,this timeframe is unrealistic given the multiple parties to be notified(i.e. Control Center, Reliability Coordinator, etc.) and the specific reference to time should be lengthened to 60 minutes. 2. In Section B,R3 this reporting requirement only makes practical sense if the voltage schedule is a range since you would deviate from a specified voltage virtually all the time. Suggest clarifying that the requirement relates to a "scheduled voltage range that takes into account voltage measuring accuracy and the dynamics of system voltage" and eliminate the reference to a reactive schedule. 3. Levels 2,3 and 4 of Non-Compliance are overly severe and should be reevaluated. Suggest tying Level 4 non compliance to 48 hours instead of 24 hours. Also,the wording regarding "time off" the voltage schedule needs to better defined(i.e. instantaneous vs. integrated)
Response: The drafting agrees and has modified the requirement to reflect the comment. The drafting team believes the Generation Operator should review the voltage schedule received from the Transmission Operator to verify the feasibility of the schedule. The drafting team believes and the industry seems to support the levels of compliance as described.			
NERC Interconnection Dynamics Working Group	Yes	No	Purpose: Replace (within limits in real time) with (within and up to equipment capabilities). R1.1 – change (status of each voltage regulator) to (status of automatic voltage regulator). R4 – Specify GSU and major auxiliary transformers connected to the generator bus. Modify in R1… regulator in service in voltage control mode, not power factor control mode
Response: The drafting team has made the changes to the purpose and requirements with the exception of the modification of R1			

because they believe it is in conflict with allowing generators to operate to a reactive schedule as described in VAR-001-1.			
Resource Issues Subcommittee	Yes	No	1. The 30 minute notification period of R3 may be too short for some small or remote generators. Suggest adding a clause "or other period agreed to by the TO". 2. R3 should be redrafted to make clear what is being required. R3 could be interpreted to mean that the GO is required to report to its TO within 30 minutes from the time that the TO requests a report, as opposed to 30 minutes after the GO cannot maintain a voltage schedule. 3. The accumulation of 8, 16, and 24 unit-hours used to determine Levels of Non-Compliance do not specify the time period over which they accumulate. 4. What is the basis for the unit-hour breakpoints in the Compliance Section and are they reasonable across the various regions of NERC? 5. Exemptions to R1 should be allowed for planned startup and shutdowns. 6. Recommend striking reference to auxiliary transformers from all sections of the standard. 7. Add to R4 - Prior to agreeing to changes in the main step-up transformer tap settings, the Generator Operator shall consider and plan for changes to those settings and adjust auxiliary systems as necessary. 8. Please clarify that R3 does not require the GO to monitor grid voltage every 30 minutes. The GO should monitor its adherence to the TO's voltage schedule.
Response: The drafting agrees and has modified the requirement to reflect the comment. The drafting team believes R3 is clear as written. ~~The drafting team notes t~~The performance reset timeframe is one calendar year per section D.1.2. The reset timeframe is the time period over which the violations accumulate. The unit-hour timeframes was a carryover from the original planning documents. The drafting team believes this issue is covered in R1- refer to the word “connected”.			

The standard has been modified to address the concern regarding "auxiliary transformer". The drafting team has modified ~~the standard regarding~~ R4 as suggested. The Generation Operator shall report within 30 minutes any deviations from the schedule.			
Southern Company – Transmission	Yes	No	R1.3 - Add the qualifier -upon request-. Recommend revising to say, -Upon request, each Generator Operator shall report to its Transmission Operator the date, time, duration, and reason for each period when a voltage or reactive schedule for a generator was not maintained. The Generator Operator shall maintain a written log of this information for 12 rolling months.- R5 - Strike the words -and auxiliary-. There is no transmission reliability need for generators to provide the auxiliary transformer information to the specified entities. After ….and NERC,….add the words -prior to equipment changes and- …… Five (5) business days is not reasonable and should be increased to 14 calendar days.
Response: ~~The drafting team has made modifications to the requirements to reflect the comment on R1.3.~~ R1.3 was revised to change the verbal report to a written log. The associated measure indicates that this information must be made available to the TOP 'on request.' ~~The drafting team believes this issue is covered in R1- refer to the word "connected".~~ The standard has been modified to address the concern regarding "auxiliary transformer". The drafting team believes the suggested wording change to R5. is not necessary as it is covered in the MOD-XXX standards. The ~~drafting team has modified~~ time for providing the information was changed from five business days to 30 calendar days as suggested.			
Southern Company Generation	Yes	No	R1.3 - Add the qualifier "upon request". R3 - The requirement for the Generator Operator to monitor grid voltage every 30 minutes is a new and unnecessary burden on the plant operator. Also, the log is only needed when the Transmission Operator does not

			approve present voltage or reactive output. R3 is needed only to address the documentation for cases when the plant operator cannot meet R2. Recommend revising R3 to say, "Each Generator Operator shall maintain a written log of the date, time, duration, and reason for each period when a voltage and reactive schedule for a generator was not maintained as specified by the Transmission Operator. This log shall be maintained for 12 rolling months." This will minimize paperwork, because it will result in a log entry only when either the plant operator cannot meet the transmission operator's requirement or does not get the transmission operator's concurrence." R5 - Strike the words "and auxiliary". There is no transmission reliability need for generators to provide the auxiliary transformer information to the specified entities. This should be removed here and included in the Nuclear Offsite Power Reliability Standard. Five (5) business days is not reasonable and should be increased to 14 calendar days.
Response: The drafting team has made modifications to the requirements to reflect the comment on R1.3. The Generation Operator shall report within 30 minutes any deviations from the schedule. R3.1 was modified to support the intent of your suggestion regarding documenting only instances where the schedule isn't maintained. ~~The drafting team believes this issue is covered in R1- refer to the word "connected".~~ The standard has been modified to address the concern regarding "auxiliary transformer". ~~The draft team has modified the standard to reflect this comment. The drafting team suggests the commentor should submit a comment to add to the mentioned SAR.~~ The drafting team ~~has modified~~ changed five business days to 30 calendar days as suggested.			
Constellation Generation Group	Yes	No	In R2, a operational range that is not harmful to the generator needs to establish and recognized by the transmission operator before a generation operator can required to be instructed to maintain a synchronous voltage or

			reactive output level by the transmission operator.
Response: The drafting team believes the Generation Operator should review the voltage schedule received from the Transmission Operator to verify the feasibility of the schedule.			
Tennessee Valley Authority SERC EC Generation Subcommittee (GS) Jerry Nicely – TVA Nuclear Generation D. Byran Guy – Progress Energy, Inc.	Yes Yes Yes	No No No	Exemptions should be allowed for planned startup and shutdowns (R1) Strike the words and auxiliary from all sections of the standard. Add to R4 - Prior to agreeing to changes in the main step-up transformer, the Generator Operator shall consider and plan for changes to those settings and adjust auxilliary systems as necessary. The requirement for the GO to monitor grid voltage every 30 minutes is a new and unnecessary burden on the plant operator.
Response: The drafting team believes this issue is covered in R1- refer to the word "connected". The drafting team has made modifications to the standard regarding "auxiliary" and R4, based on industry comment. The Generation Operator shall report within 30 minutes any deviations from the schedule.			
Carol L. Krysevig – Allegheny Energy Supply Co.	Yes	No	Is it the intent of requirement R5 that a request by any one of the three entities will require the Generator Operator provide the data to that entity or all three? In the past communication of data between the Generator Operator and the Transmission Operator was routine and at such times no parallel path was established with the Regional Reliability Organization or NERC. To prevent a violation must all such information be distributed at the same time to all three entities?
Response: The ~~drafting team believes the~~ Generator Operator only needs to respond to the requestor which may be any one of the three.			
SPP Transmission Working Group	Yes	No	No timeline for voltage schedules. R12 – no standard for NERC Votage Stability Analysis in associated limits.

Response: The draft {VAR-001}			
Mark Kuras – MAAC	Yes	No	Level of non-compliance 2.4.2 seems to imply that the TO can order the GO to make changes to their GSU tap. I thought it had to be an agreed upon change (See R4). Also this is not mentioned in the measures.
Response: The drafting teams believes the mutually agreed upon time frame also implicitly means there was a mutually agreed upon tap change.			
Individual Members of CCMC Joseph D Willson – PJM	Yes Yes	No No	Levels of non-compliance are adding requirements. The 8, 16, 24 hours must be removed. Requirements must be modified. Remove "within 30 days". This standard seems to have very similar requirements and levels of non-compliance as VAR-001. Either eliminate the redundancy (ex. Time unit was not operating with automatic voltage regular (control) in service) between the two or combine the standards.
Response: The drafting team notes the time frames mentioned in the non-compliance section existed in the original document. The drafting team does not have sufficient information to respond. The drafting team believes there is not any redundancy between VAR-001 and VAR-002.			
John K. Loftis, Jr. – Dominion – Electric Transmission	Yes	Yes	Dominion Electric Transmission agrees with moving VAR-001 R9.1 and R9.2 to VAR-002, as R1.1 and R1.2.
Response: Thank you for your comment. We have made the changes based on industry support.			
Doug Hohbough – First Energy Corp.	Yes	Yes	Proposed move os sections to VAR-002-1 is ok.
Response: Thank you for your comment. We have made the changes based on industry support			

John Horakh – MACC	Yes	Yes	OK to move R9.1 and R9.2 to VAR-002.
Response: Thank you for your comment. We have made the changes based on industry support			
PPL Corporation	Yes	Yes	PPL believes that a NERC standard should require all Generator Owners to have their Automatic Voltage Regulators (AVRs) in service and to immediately report any AVR outages to the system operator.
Response: ~~The drafting team based on other~~Most industry comments seem to support ~~believes exemptions~~ exemptions to the AVR reporting requirements~~ should be allowed~~.			
Michael C. Calimano – NYISO	Yes	Yes	The generators that are required to operate and report should be limited to those that are greater than 20 MWs or connected at 100KV and higher. NYISO recommends to remove "synchronous" throughout VAR-002-1.
Response: The ~~drafting team believes~~TOP is required to identify~~ the~~ exemption criteria for GOPs that don't need to comply with the requirements in VAR-002. ~~delineated in VAR-001-1 will address the concern about exemptions.~~ ~~The drafting team does not agree with the comment concerning R3 as i~~Induction ~~generation~~ generators generally cannot ~~generally~~ provide VA~~r~~R support so the drafting team did not remove the word, 'synchronous'.			
Consolodated Edison NPCC CP9 RSWG Kathleen Goodman – ISO-NE IESO – Ontario Cinod Kotecha Alan Adamson – NYSRC Ed Riley – California	Yes Yes Yes Yes Yes Yes Yes	Yes Yes Yes Yes Yes Yes Yes	The generators that are required to operate and report should be limited to those that are considered to be part of the Bulk Electric System.

ISO ISO/RTO Council Standards Review Committee			

Response: The TOP is required to identify exemption criteria for GOPs that don't need to comply with the requirements in VAR-002.

~~The drafting team believes the exemption criteria delineated in VAR-001-1 will address the concern about exemptions.~~

Transmission Issues Subcommittee	Yes		Remove reference to "synchronous" throughout the standard. Clarify that R1 applies to all generators capable of automatic mode AVR operation. The translation table refers to R6, which is not in this standard.

Response: Induction generators generally cannot provide VAR support so the drafting team did not remove the word, 'synchronous'.

~~USE {VAR-001}~~ The drafting team has modified R1 based on industry comment.

This was a typographical error and has been removed.~~e drafting team acknowledges this error in reference to R6 and thanks you for your comment.~~

Barry Green – Ontario Power Generation	Yes		R1.1 - There are some generating units that by virtue of their location and/or size have diminimus impact on transmission system limits. The standard should have provision for exclusion from this requirement for such units. R1.2 - The purpose of R1.2 is unclear. The AVR is used to respond to transient conditions, not to meet schedules as instructed by a Transmission Operator or Reliability Authority. Meeting such schedules is done by operator manual adjustments, whether the AVR is in service or not. R2 - A Generator Obligation to "maintain" generator voltage or ractive oputput could be problematic. During transient conditions, attempting to maintain reactive output at a level specified under steady-state conditions could exacerbate a problem.

			R5 - The term "auxiliary transformers" should be defined to refer only to those transmformers connected directly to the tranmission system. R5 - The obligations included here in are not included in Existing Standards M2, M4 or M6. Either there is another standard that is being superceded by these standards which should be listed or this requirement should be moved to an alternative standard. Levels of Non-Compliance: See additional comments in reponse to question 4
Response: The TOP is required (in VAR-001 R3) to identify exemption criteria for GOPs that don't need to comply with the requirements in VAR-002. ~~The drafting team believes the exemption criteria delineated in VAR-001-1 will address the concern about exemptions. Regarding~~ R1.2: AVR response is taken into consideration in determining voltage schedule, as the AVR will maintain the voltage schedule. In the event of AVR failure the transmission operator may direct the Generator Operator to a new voltage schedule to compensate for the loss of the transient response of the excitation system; no change is needed. The drafting team has modified the standard in response to industry comment on auxiliary transformers. The obligations included in this standard are interpretations from planning standards IIIC M2, M4, M6;			
Transmission Subcommittee			VAR-002-1, R2, TS suggests the last part of R2 is assumed to be within the proposed R2 language and recommends the R2 language be modified as follows: Each Generator Operator shall maintain the synchronous generator voltage or reactive output "within the reactive capability of the unit as "specified (delete)" "directed (add)" by the Transmission Operator. "unless otherwise approved by the Transmission Operator. (Delete)." VAR-002-1, R3, TS recommends referencing "within 30 minutes" be anchored to a start time, end lime, or another reference point. By itself, the "within 30 minutes" is ambiguous. TS Consideration: The TS is concerned that this standard may not be the most optimal location for "documentation and reporting" requirements. If the reporting criteria is contained within a "Documentation and Reporting"

			standard, then the respective requirements should be deleted from this standard. (example: VAR-002-1, R3) VAR-002-1, M2, TS Recommendation: M2 lacks a "within X amount of time" that other measures contain. To be consistent with other standards, a reporting window should be included.
Response: The drafting team has made the appropriate modification. The drafting team does not agree the wording is ambiguous. If at a future time there is a new standard developed that addresses all documentation and reporting, then this standard can be modified at that time. Until then, the documentation and reporting that are addressed in this standard seem to be supported by most industry commenters. The time frame is "available on request".			
Midwest Reliability Organization	Yes	Yes	Move VAR-001 R9.1 and R9.2 to VAR-002 R1.1 so that all Generator Owner requirements are together. R1.3 Should the standard allow for an exemption for smaller units? R3. Reference necessary in this standard to TOP-002-0 R14.
Response: The drafting team did move VAR-001 R9.1 and R9.2 as suggested. The TOP is required (in VAR-001 R3) to identify exemption criteria for GOPs that don't need to comply with the requirements in VAR-002. ~~has made the referenced modification to the standard. The drafting team believes the exemption criteria delineated in VAR-001-1 will address the concern of relative impact. The~~ The drafting agrees the language is somewhat redundant but will modify R14 of TOP-002 because the VAR-002-1 is more comprehensive and requirements should only reside in one standard.			
Raj Rana – AEP	Yes	Yes	Reword R4 as follows: When mutually agreed with the Transmission Operator, the Generator Operator shall change transformer tap positions… upon time frame.
Response: ~~The drafting team has made this modification.~~R4 was reworded to support the intent of this suggestion.			

Peter Burke – American Transmission Co.	Yes	Yes	Move VAR-001 R9.1 and R9.2 to VAR-002 so that all generator owner requirements are together. Revise M3 to contain "available upon request"
Response: The drafting team ~~has made the appropriate modification.~~ did move VAR-001 R9.1 and R9.2 as suggested. The phrase, 'available upon request' was added to M3 as suggested.			
Entergy	Yes	Yes	
Karl Kohlrus - City Water, Light & Power	Yes	Yes	
Ronnie Frizzell - Arkansas Electric Coop. Corp.	Yes	Yes	
Howard Rulf - WE Energies	Yes	yes	
Joseph F. Buch – Madison Gas and Electric	Yes		
Samuel W. Leach – TXU Power	Yes	Yes	
Xcel Energy – Northern States Power	Yes	Yes	
SERC EC Planning Standards	Yes	Yes	

Subcommittee (PSS)			
Dan Griffiths – PA Office of Consumer Advocate	Yes	Yes	
Gerald Rheault – Manitoba Hydro	Yes	Yes	
WECC Reliability Subcommittee	Yes	Yes	
Mohan Kondragunta – Southern California Edison	Yes	Yes	

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

This proposed standard is a translation of planning measure III.C.M2, III.C.M4, and III.C.M6, which was not included in the approval Version 0 reliability standards because it required further work.

Development Steps Completed:

1. A SAR was posted from December 2, 2004, through January 7, 2005.
2. The SAC appointed a standard drafting team on January 13, 2005.
3. The drafting team posted its response to SAR comments and all other historical comments on April 19, 2005.
4. The drafting team posted Draft 1 of the standard on April 21, 2005.

Description of Current Draft:

This is a first draft of the standard to be posted for industry comment.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Close Draft 1 comment period.	June 6, 2005
2. Review comments from industry posting and determine if the draft standard is ready for ballot.	July 15, 2005
3. Post for 30-day pre-ballot period.	August 1, 2005
4. Conduct ballot.	September 1, 2005
5. Post for 30-day period prior to Board adoption.	October 1, 2005
6. Board adoption and effective date.	November 1, 2005

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

No new definitions are proposed for this standard.

A. Introduction

1. **Title:** **Generator Operation for Maintaining Network Voltage Schedules**

2. **Number:** VAR-002-1

3. **Purpose:** To ensure generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained within and up to ~~limits in real time~~ equipment capabilities to protect equipment and the reliable operation of the Interconnection.

4. **Applicability**

   4.1. Generator Operator.

5. **Proposed Effective Date:** November 1, 2005.

B. Requirements

R1. The Generation Operator shall operate each synchronous generating unit connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless otherwise approved by the Transmission Operator.

R1.1. Each Generator Operator shall inform its Transmission Operator within 30 minutes of a status change on any synchronous generator reactive power resource, including the status of each automatic voltage regulator and power system stabilizer.

R1.2. When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or reactive schedule directed by the Transmission Operator.

R1.3. Each Generator Operator shall ~~shall~~ maintain a written log of ~~report to its Transmission Operator~~ the date, time, duration, ~~and~~ reason, and time of notification to the Transmission Operator for each period when a synchronous generator was not operated in the automatic voltage control mode and shall maintain ~~a written log of~~ this information for 12 rolling months.

R2. Each Generator Operator shall maintain the synchronous generator voltage or reactive output (within the unit capability) as specified by the Transmission Operator, unless otherwise approved by the Transmission Operator.

R3. Each Generator Operator shall maintain the synchronous generator voltage or reactive output "within the reactive capability of the unit as "specified (delete)" "directed (add)" by the Transmission Operator. "unless otherwise approved by the Transmission Operator.

~~R3.~~Each Generator Operator shall report within 30 minutes (or within the mutually agreed to timeframe with the Transmission Operator) to its Transmission Operator ~~the date, time, duration, and reason for each period~~ when a voltage and reactive schedule for a generator is not maintained.~~, and shall maintain a written log of this information, including concurrence of the Transmission Operator, for 12 rolling months.~~

R4.

R4.1. Each Generator Operator shall maintain a written log of the date, time, duration, reason, and time of notification to the Transmission Operator, and their concurrence for each period when a voltage schedule or reactive schedule was not maintained. This information shall be maintained for 12 rolling months.

~~R4.~~R5. When mutually agreed with the Transmission Operator, the Generator Operator shall change transformer no load tap positions (and voltage reference setting for load-tap changing transformers, as appropriate) according to the documentation provided by the Transmission Operator within a mutually agreed upon time frame.

R5.1. Prior to agreeing to changes in the main step-up transformer tap settings, the Generator Operator shall consider and plan for changes to those settings and adjust auxiliary systems as necessary.

~~R5.~~R6. The Generator Operator shall provide the tap settings, t~~and t~~he available tap ranges, and for load-tap changing transformers the +/- voltage range with step-change in % and impedance data for generator step-up transformer and auxiliary transformers with primary voltages no less than the generator terminal voltage ~~-~~to the Transmission Operator, Regional Reliability Organization, and NERC, within ~~five business~~30 calendar days of a request.

C. Measures

M1. The Generator Operator shall provide to the Transmission Operator, the Regional Reliability Organization, and NERC, within 30 calendar days of a request, information on the operation of the synchronous generator's excitation system (including automatic voltage regulators) according to the Transmission Operator's procedures for synchronous generators.

M2. The Generator Operator has available on request a log that specifies the date, duration, and reason for not maintaining the established voltage or reactive power schedule, along with approvals for such operation received from the Transmission Operator.

M3. The Generator Operator has available upon request documentation of tap settings and changes, available tap ranges, and impedances for generator step-up and auxiliary transformers.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

The Generator Operator shall maintain a written log of this information for 12 rolling months**.**

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Generator Owner shall demonstrate compliance through self certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: There shall be a Level 1 non-compliance if any of the following conditions exist:

2.1.1 Logs indicate incidents, subsequent to the 30-minute notification period, of synchronous generator operation off the voltage or reactive schedule or operation without automatic voltage control, for an accumulated time of less than 8 unit-hours for an individual generator without Transmission Operator concurrence.

2.1.2 Documentation of tap settings and changes, available tap ranges, and impedances for generator step-up and auxiliary transformers is not complete.

2.2. Level 2: Logs indicate incidents, subsequent to the 30-minute notification period, of synchronous generator operation off the voltage or reactive schedule, or operation without automatic voltage control, for an accumulated time of less than 16 unit-hours for an individual generator without Transmission Operator concurrence.

2.3. Level 3: Logs of synchronous generator operation off the voltage or reactive schedule, or reactive schedule were incomplete, or the logs indicate incidents, subsequent to the 30-minute notification period, of operating off the voltage or reactive schedule or operation without automatic voltage control, for an accumulated time of less than 24 unit-hours for an individual generator without Transmission Operator concurrence.

2.4. Level 4: There shall be a Level 4 non-compliance if any of the following conditions exist:

2.4.1 Logs of synchronous generator operation off the voltage or reactive schedule were not provided, or the logs indicate incidents, subsequent to the 30-minute notification period, of operating off the voltage or reactive schedule or operation without automatic voltage control for an accumulated time of more than 24 unit-hours for an individual generator without Transmission Operator concurrence.

2.4.2 Generator operator did not change tap settings as requested by the Transmission Operator during the mutually agreed upon time frame.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

<table>
<tr><th>Commenter</th><th>Reliability Need</th><th>Acceptable Translation</th><th>Comments</th></tr>
<tr><td>Les Pereira P.E.</td><td></td><td></td><td>Please see VAR-001-1</td></tr>
<tr><td colspan="4">Response: Please see consideration of comments on VAR-001.</td></tr>
<tr><td>Carson Taylor – Bonneville Power Administration</td><td></td><td></td><td>Static and dynamic reactive power must be carefully defined. Preferably, better terms should be used.

“Static” usually is taken to mean fixed or mechanically switched capacitor/reactor banks, and that mechanical switching is operator-directed in a slow time frame (basically fixed). At BPA and at other companies capacitor/reactor banks are rapidly switched following disturbances by local voltage relays, SPS/RAS, or within a few minutes via SCADA operators. Fraction of a second switching is used by both voltage relays and SPS/RAS. During the June 14, 2004 loss of 4600 MW of Arizona generation event, BPA shunt and series capacitor banks and shunt reactors switched during the first forward angle swing by voltage relays and RAS. Operators switched other banks within two minutes as voltage again decayed because of Northwest governor action. A circuit breaker is pretty dynamic.

The problem that shunt capacitor bank output is a function of voltage-squared is dealt with in design by the control settings, bank sizes, and number of banks so that the voltage is not allowed to collapse.

The word “static” is used in “static var compensator” to mean power electronic rather than mechanical switching.

“Continuous automatic control” and “discontinuous automatic control” might be better terms. Better yet, why not a simple statement that various types of reactive power resources at effective locations must be planned and operated to meet performance requirements?</td></tr>
<tr><td colspan="4">Response:</td></tr>
<tr><td>Tennessee Valley Authority</td><td>Yes</td><td>No</td><td>TVA agrees that there is a reliability need, but it feels that the intent of this sstandars is already covered in TPL-001 thru 004</td></tr>
</table>

Response: The blackout of August, 2003 highlighted a need to do more detailed assessments of reactive power resources. Some entities already look at reactive power resources when they conduct the planning assessments required to comply with TPL-001 through TPL-004. Other entities, however, have not been assessing their reactive power resources, and by highlighting the requirements to conduct reactive power resource assessments in a new standard, it gives these new requirements a bit more stature than if they were embedded within the existing TPL-001 through TPL-004 standards.			
Kansas City Power and Light	Yes	No	It appears this standard is redundant with other standards
Response:			
Gerald Rheault – Manitoba Hydro	No	Yes	The adequacy of reactive power resources is verified by system assessments in TPL-001 to 004. Meeting the performance requirements implies adequate resources. This standard is redundant. A standard defining a minimum reactive reserve requirement may be more meaningful.
Response:			
Midwest Reliability Organization	No	No	Merge requirements in R1 of VAR-003-1 into TPL-001-0, TPL-002-0, and TPL-003-0 with requirement in Measures of the TPL standards for review and assessment once every five years. R2 has the same intent as R1.3.9 in the TPL standards. R3 is identical to R3 of the TPL standards. VAR-003 can now be eliminated.
Response:			
Greg Ludwicki – Northern Indiana Public Service Co.	Yes	No	I interpret requirement for an annual test. Recommend a longer time frame unless operational anomalies are encountered, possibly 5 years.
Response: Nothing in the standard indicates that the assessment must be conducted annually.			

The standard was modified to change the interval for conducting assessments from 'at least once every 5 years' to 'at least once every 3 years'.			
SPP Transmission Working Group Ronnie Frizzell - Arkansas Electric Coop. Corp.	Yes Yes	No No	Requirement for developing a methodology and criteria for the assessment reactive resources should be done on a regional baisis and therefore should be the responsibility of RRO.
Response:			
John Horakh – MACC	Yes	No	The need to have a balance between static and dynamic reactive power resources is stated in the Purpose. The need should also be explicitly stated in the measures.
Response:			
FRCC	Yes	No	Delete R1 – Since the methods and criteria are Region and area specific, this requirement cannot be used to determine if the "correct" methods and criteria are being applied. The reactive assessment should be comprehensive and should not be limited in scope by methods and criteria that were previously adopted. As the system changes over time, with load growth and new facilities, any methods and criteria may need to be changed in order to correctly assess the correct balance between static and dynamic reactive power requirements. R2 & R3 are adequate to ensure that the system has adequate reactive resources in the correct balance.
Response:			
Peter Burke – American Transmission Co.	Yes	No	R2.2 Suggest more frequent assessments, such as at least every three years M1 ...NERC within 30 calendar days... M2 Suggest assessment within the past three years D1.3 ...Compliance Monitor shall retain any audit data for at least five years. [three

			year is okay, if M2 is within the past three years] D2.2 What is the definition of an area? D2.3 R1 does not require review within the past five years D2.4 What is the definition of areas? Does this have to be a new stand-alone standard? It appears that the requirements lend themselves to be merged within TPL-001, TPL-002 and TPL-003.
Response: The standard was modified to change the interval for conducting assessments from 'at least once every 5 years' to 'at least once every 3 years'.			
Joseph D Willson – PJM	Yes	No	Level 2 and 4: who determines if the TP and/or PA assessment is incomplete in one area (since no areas are defined in the requirement.
Response:			
Individual Members of CCMC	Yes	No	Level 2 and 4: Who determines if the TP and/or PA assessment is incomplete in one area (since no areas are defined in the requirement). This should probably be included in the TPL standards.
Response:			
Mark Kuras – MAAC	Yes	No	Every requirement and measurement seems to imply that the TP and PA must redundantly do things. The …and… should be an …or… Level 3 non-compliance should be another sub-section of Level 4.
Response:			
WECC Reliability Subcommittee Mohan Kondragunta –	Yes Yes	Yes Yes	SCE supports this Standard. Existing WECC Standards address these requirements.

Southern California Edison			
Response:			
Alan Adamson – NYSRC	Yes	Yes	R2.2 should require that assessments be performed at least every two years, instead of every five years.
Response: Several commenters suggesting making this a shorter time period than every five years – some suggested every two years and some suggested every three years and the drafting team selected three years as a compromise.			
Xcel Energy – Northern States Power	Yes	Yes	Requirement R2 - "shall acquire" is a financial term, not a guidance term. Recommend change to "shall maintain". Requirement R5.1 - "shall notify the Generator Operator of a voltage schedule or reactive output " is not clear. Recommend change to " the Transmission Operator shall direct the Generator Operator to either maintain or change its voltage schedule or reactive output as necessary" R2. Transfers involving designated network resources should also be included in theis requirement. M1. the timeframe should be 30 calendar days not 3.
Response: Agree – M1 should have said 30 calendar days and this typographical error has been corrected.			
Transmission Subcommittee			VAR-003-1, R2.2., TS recommends rewording the R2.2. language as follows: The Transmission Planner and Planning Authority shall each perform this assessment at least once every "five (delete)" "three (add)" years or as required by "significant (add)" changes in system conditions "which may affect static and dynamic reactive power requirements. (add)" VAR-003-1, R2.2., TS Consideration: The term "changes in system conditions" is very liberal. TS recommends defining these changes as being significant to the assessment study (e.g. load growth, generation additions, dynamic and static

			reactive power additions or deletions, changes in operations, etc.). VAR-003-1, M1: TS believes that M1 requirement to provide evidence within "3 calendar days" is a typographical error and actually is "30 calendar days." TS believes 30 calendar days is a realistic time span for a request-documentation reporting window. VAR-003-1, M3: TS recommends an assessment every three years to coincide with recommended "three years" in R2, above.
The standard was modified to change the interval for conducting assessments from 'at least once every 5 years' to 'at least once every 3 years'. Response: Agree – M1 should have said 30 calendar days and this typographical error has been corrected.			
Consolodated Edison	Yes	Yes	R2.2 should require that assessments be performed at least every two years, instead of every five years.
Response: Several commenters suggesting making this a shorter time period than every five years – some suggested every two years and some suggested every three years and the drafting team selected three years as a compromise.			
Transmission Issues Subcommittee	Yes	Yes	R2.2 should state that assessments should be performed at least every two years, rather than five years. As approved by the NERC BOT, TIS recommends that Standard I.D guidelines G2 and G3 should be incorporated into this standard as follows: Distribution entities and customers directly connected to the transmission system should plan their respective systems to operate close to a specified power factor; and, at continuous rated power output, new generators should have an overexcited power factor capability, measured at the point of interconnection with the transmission system, of 0.95 or less and underexcited power factor of 0.95 or less. If a generator does not meet this requirement, the generation owner should make alternate arrangements (e.g. Statcoms, SVC, etc.) for supplying an equivalent dynamic reactive power capability to meet this requirement. (The drafting team should coordinate the generator power factor requirement with MOD-025-1.)

			M1 should refer to 30 calendar days, not 3.
Response: Several commenters suggesting making this a shorter time period than every five years – some suggested every two years and some suggested every three years and the drafting team selected three years as a compromise. Agree – M1 should have said 30 calendar days and this typographical error has been corrected.			
John K. Loftis, Jr. – Dominion – Electric Transmission	Yes	Yes	Dominion Electric Transmission concurs with the addition of Planning Authorities to the list of applicable responsible parties and with including an additional requirement to develop a method and criteria for assessing adequacy of reactive power resources. Suggest that R2.1 be deleted. The requirements of R2.1 are included in R2.2. M1 should refer to 5 business days instead of 3 calendar days (typical Standards practice). The areas referred to D.2.2 and D.2.4.2 needs to be clarified.
Response: M1 should have said 30 calendar days and this typographical error has been corrected. Five business days is probably not a realistic timeframe for reporting this information.			
Entergy SERC EC Planning Standards Subcommittee (PSS)	Yes Yes	Yes Yes	Suggest that R2.1 be deleted. The requirements of R2.1 are included in R2.2. M1 should refer to 5 business days instead of 3 calendar days (typical Standards practice). The "areas" referred to D.2.2 and D.2.4.2 needs to be clarified.
Response: M1 should have said 30 calendar days and this typographical error has been corrected. Five business days is probably not a realistic timeframe for reporting this information.			
Cinod Kotecha	Yes	Yes	The M1 response time should be 30 days, not 3? R2.2 should require that assessments be performed every year. Regions should be allowed to continue present practices.
Response: M1 should have said 30 calendar days and this typographical error has been corrected.			

IESO – Ontario NPCC CP9 RSWG Kathleen Goodman – ISO-NE Ed Riley – California ISO ISO/RTO Council Standards Review Committee	Yes Yes Yes	Yes Yes Yes	The M1 response time should be 30 days not 3
Response: M1 should have said 30 calendar days and this typographical error has been corrected.			
Michael C. Calimano – NYISO	Yes	Yes	"Changes in system conditions" is vague and needs to be clarified. M3 assesment should be done every 3 years to coincide the R2 requirement.
Response: The standard was modified to change the interval for conducting assessments from 'at least once every 5 years' to 'at least once every 3 years'.			
Doug Hohbough – First Energy Corp.	Yes	Yes	The compliance reset timeframe should be five years. There would be no advantage to assessing compliance this year and returning next year to assess it again when the requirement is every 5 yrs.
Response:			
Dan Griffiths – PA Office of Consumer Advocate	Yes	Yes	
Howard Rulf - WE	Yes	yes	

Energies			
PPL Corporation	Yes	Yes	
Raj Rana – AEP	Yes	Yes	
Deborah M. Linke – US Bureau of Reclamation	Yes	Yes	
Karl Kohlrus - City Water, Light & Power	Yes	Yes	
Carol L. Krysevig – Allegheny Energy Supply Co.	Yes	Yes	
Rebecca Berdahll – Bonneville Power Administration Karl Bryan – Corp of Engineers Jay Sietz – US Bureau of Reclamation Brenda Anderson	Yes	Yes	
Gred Mason – Dynergy Generation	Yes	Yes	

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

This proposed standard is a translation of planning measure I.D.M1, which was not included in the approval Version 0 reliability standards because it required further work.

Development Steps Completed:

1. A SAR was posted from December 2, 2004, through January 7, 2005.
2. The SAC appointed a standard drafting team on January 13, 2005.
3. The drafting team posted its response to SAR comments and all other historical comments on April 19, 2005.
4. The drafting team posted Draft 1 of the standard on April 21, 2005.

Description of Current Draft:

This is a first draft of the standard to be posted for industry comment.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Close Draft 1 comment period.	June 6, 2005
2. Review comments from industry posting and determine if the draft standard is ready for ballot.	July 15, 2005
3. Post for 30-day pre-ballot period.	August 1, 2005
4. Conduct ballot.	September 1, 2005
5. Post for 30-day period prior to Board adoption.	October 1, 2005
6. Board adoption and effective date.	November 1, 2005

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

No new definitions are proposed for this standard.

A. Introduction

1. **Title:** **Assessment of Reactive Power Resources**

2. **Number:** VAR-003-1

3. **Purpose:** To ensure that reactive power resources, considering~~with a balance between~~ static and dynamic characteristics, are planned and distributed throughout the interconnected transmission systems.

4. **Applicability**

   4.1. Transmission Planner.

   4.2. Planning Authority.

5. **Proposed Effective Date:** November 1, 2005.

B. Requirements

R1. The Transmission Planner and Planning Authority shall each establish a method and criteria for assessing adequate static and dynamic reactive power requirements. The method and criteria shall be reviewed at least once every five years.

R2. The Transmission Planner and Planning Authority shall each conduct assessments to ensure static and dynamic reactive power resources are adequate to meet projected customer demands, firm (non-recallable) electric power transfers, and the system performance requirements as defined in TPL-001, TPL-002, and TPL-003.

R2.1. In its assessment of reactive power resources, the Transmission Planner and Planning Authority shall each address how known changes in system conditions may affect system reliability.

R2.2. The Transmission Planner and Planning Authority shall each perform this assessment at least once every three~~five~~ years or as required by significant unanticipated changes in system conditions (e.g. load growth, generation additions, dynamic and static reactive power additions or deletions, changes in operations, etc.) that may affect static and dynamic reactive power requirements.

R3. The Transmission Planner and Planning Authority shall each document its assessments of reactive power resources and shall provide these assessments to the Regional Reliability Organization and NERC when requested.

C. Measures

M1. The Transmission Planner and Planning Authority shall each have evidence that it developed, and reviewed within the previous five years, a method and criteria for assessing the adequacy of reactive power resources in accordance with VAR-003 R1 and shall provide this evidence to its Regional Reliability Organization and NERC within 30 calendar days of a request.

M2. The Transmission Planner and Planning Authority shall each have evidence it conducted an assessment of its reactive power resources within the past three~~five~~ years or as required by system conditions, in accordance with VAR-003 R2.

M3. The Transmission Planner and Planning Authority shall each have evidence it provided documentation of the results of its most recent reactive power resource assessment to its Regional Reliability Organization within 30 calendar days of a request.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

The Transmission Planner and Planning Authority shall retain the current assessment.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Transmission Planner and Planning Authority shall demonstrate compliance through self certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: Assessments of reactive power resources were incomplete~~te in one area~~.

2.3. Level 3: The Transmission Planner or Planning Authority have not reviewed the method and criteria for assessing adequate static and dynamic reactive power requirements within the last five years.

2.4. Level 4:

2.4.1 The Transmission Planner or Planning Authority did not provide evidence that it has a method and criteria for assessing adequate static and dynamic reactive power requirements, or

2.4.2 The Transmission Planner or Planning Authority did not provide evidence that it has a performed an assessment of static and dynamic reactive power requirements.~~Assessments of reactive power resources were incomplete in more than one area.~~

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking