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

Phase III-IV Standard Drafting Team Meeting

January 4–5, 2006

San Diego, CA

Agenda

1. Introductions and Antitrust and Administrative (**Attachment 1a**)
2. Review Meeting Objectives:
   - Finalize edits to all of the following so they can be posted on February 1, 2006:
     - Standards and Redline to 2nd draft of each standard in Set Two of Phase III-IV (**Attachments 2a** through **2h**)
     - Consideration of Comments (**Attachment 3**)
     - Implementation Plan (**Attachment 4**)
     - Draft Field Test Plan for PRC-019, MOD-026, and MOD-027 for submission to SAC on January 8–9 (**Attachment 5**)
     - Review SAC's responses to field test plan for PRC-024 and draft letter asking for volunteers (**Attachment 6**)
     - Action Plan for completing standards (**Attachments 7a** and **7b**)
3. Review the Consideration of Comments in the following order, making conforming changes to standards as needed:
   - EOP-005 — System Restoration Plans
   - MOD-013 — Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures
   - MOD-026 — Verification of Models and Data for Generator Excitation System Functions
   - MOD-027 — Verification of Generator Unit Frequency Response
   - VAR-001 — Voltage and Reactive Control
   - VAR-002 — Generator Operation for Maintaining Network Voltage Schedules
   - VAR-003 — Assessment of Reactive Power Resources
4. Review the Implementation Plan, stopping to address any identified issue.
5. Review the Action Plan for completing the standards
6. Develop a task force to draft a Field Test Plan for PRC-019, MOD-026, and MOD-027
7. Select date for next meeting.

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NERC ANTITRUST COMPLIANCE GUIDELINES

I. GENERAL

It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition.

It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

II. PROHIBITED ACTIVITIES

Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

Approved by NERC Board of Trustees, June 14, 2002
Technical revisions, May 13, 2005

III. ACTIVITIES THAT ARE PERMITTED

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation and Bylaws are followed in conducting NERC business. Other NERC procedures that may be applicable to a particular NERC activity include the following:

- Reliability Standards Process Manual
- Organization and Procedures Manual for the NERC Standing Committees
- System Operator Certification Program

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of the mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.

- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.

- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.

- Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

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 the Version 0 EOP-005 modified to include a translation of planning measures 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 from 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.

Description of Current Draft:

This is the second draft of the standard to be posted for industry comment from October 15 –November 30, 2005.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Review comments from industry posting; post consideration of comments.	December 1 – January 15, 2006
2. Post revised standards and implementation plan for 45 day comment period	January 15 – February 28, 2006
3. Review comments from industry posting; post consideration of comments	April 1, 2006
4. Post standards and implementation plan for 30-day pre-ballot review.	April 15 - May 15, 2006
5. Conduct 1st ballot.	May 20-30, 2006
6. Consider comments submitted with 1st ballot; post consideration of comments	June 1-18, 2006
7. Conduct 2nd ballot.	June 19-29, 206
8. Post standards and implementation plan for 30-day review by Board.	July 1-30, 2006
9. Board adoption date.	August 1, 2006
10. Proposed Effective date.	August 1, 2007

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:** August 1, 2007.

B. Requirements

R1. Each Transmission Operator shall have a restoration plan to reestablish 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. Each Transmission Operator shall include the applicable elements listed in Attachment 1-EOP-005 in developing a restoration plan.

R2. Each Transmission Operator shall review and update its restoration plan at least annually and whenever it makes changes in the power system network, 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.

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. The Transmission Operator shall document the Cranking Paths, including initial switching requirements, between each blackstart generating unit and the unit(s) to be started and shall provide this documentation to the Regional Reliability Organization upon request. Such documentation may include Cranking Path diagrams.

R10. The Transmission Operator shall demonstrate, through simulation or testing, that the blackstart generating units in its restoration plan can perform their intended functions as required in the Regional restoration plan.

R10.1. The Transmission Operator shall perform this simulation or testing at least once every five years.

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

R11.1. 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. The affected Transmission Operators and Balancing Authorities shall take the necessary actions to restore Bulk Electric System frequency to normal, including adjusting generation, placing additional generators online, or load shedding.

R11.3. 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. The affected Transmission Operators shall give high priority to restoration of off-site power to nuclear stations.

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

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

R11.5.2. 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.

R11.5.4. 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 blackstart units and Cranking Paths identified in the Transmission Operator's restoration plan can perform their intended functions as required in the Regional restoration plan.

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

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 is not reviewed annually.

2.2. Level 2: Plan exists but does not address one of the elements listed in Attachment 1-EOP-005.

2.3. Level 3: Did not make available documentation 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 in Attachment 1-EOP-005.

2.4.2 No restoration plan in place.

2.4.3 No simulation or test results as required in EOP-005 R10.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

Attachment 1-EOP-005-0

Elements for Consideration in Development of Restoration Plans

The Restoration Plan must consider the following requirements, as applicable:

1. Plan and procedures outlining the relationships and responsibilities of the personnel necessary to implement system restoration.
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.
3. The plan must account for the possibility that restoration cannot be completed as expected.
4. The necessary operating instructions and procedures for synchronizing areas of the system that have become separated.
5. The necessary operating instructions and procedures for restoring loads, including identification of critical load requirements.
6. A set of procedures for simulating and, where practical, actually testing and verifying the plan resources and procedures (at least every three years).
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.
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.)
9. Notification shall be made to other operating entities as the steps of the restoration plan are implemented.

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 the Version 0 MOD-013 modified to include a translation of a part of planning measure II.B.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 from 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.

Description of Current Draft:

This is the first draft of the standard to be posted for industry comment from October 15 –November 30, 2005.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Review comments from industry posting; post consideration of comments.	December 1 – January 15, 2006
2. Post revised standards and implementation plan for 45 day comment period	January 15 – February 28, 2006
3. Review comments from industry posting; post consideration of comments	April 1, 2006
4. Post standards and implementation plan for 30-day pre-ballot review.	April 15 - May 15, 2006
5. Conduct 1st ballot.	May 20-30, 2006
6. Consider comments submitted with 1st ballot; post consideration of comments	June 1-18, 2006
7. Conduct 2nd ballot.	June 19-29, 206
8. Post standards and implementation plan for 30-day review by Board.	July 1-30, 2006
9. Board adoption date.	August 1, 2006
10. Proposed Effective date.	August 1, 2007

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:** **Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures**

2. **Number:** MOD-013-1

3. **Purpose:** To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems.

4. **Applicability:**

   4.1. Regional Reliability Organization.

5. **Effective Date:** February 1, 2007

B. Requirements

R1. The Regional Reliability Organization, in coordination with its Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners, shall develop comprehensive dynamics data requirements and reporting procedures needed to model and analyze the dynamic behavior or response of each of the NERC Interconnections: Eastern, Western, and ERCOT. Within an Interconnection, the Regional Reliability Organizations shall jointly coordinate on the development of the data requirements and reporting procedures for that Interconnection. Each set of Interconnection-wide dynamics data requirements shall include the following dynamics data requirements:

R1.1. Design data shall be provided for new or refurbished excitation systems at least one year prior to the in-service date with updated data provided once the unit is in service.

R1.2. Unit-specific dynamics data shall be reported for generators and synchronous condensers (including, as appropriate to the model, items such as inertia constant, damping coefficient, saturation parameters, and direct and quadrature axes reactances and time constants), excitation systems, voltage regulators, turbine-governor systems, power system stabilizers, and other associated generation equipment.

R1.2.1. Estimated or typical manufacturer's dynamics data, based on units of similar design and characteristics, may be submitted when unit-specific dynamics data cannot be obtained. In no case shall other than unit-specific data be reported for generator units installed after 1990.

R1.2.2. The Interconnection-wide requirements shall specify unit size thresholds for permitting:

- The use of non-detailed vs. detailed models,
- The netting of small generating units with bus load, and
- The combining of multiple generating units at one plant.

R1.3. Device specific dynamics data shall be reported for dynamic devices, including, among others, static VAR controllers, high voltage direct current systems, flexible AC transmission systems, and static compensators.

R1.4. Dynamics data representing electrical demand characteristics as a function of frequency and voltage.

R1.5. Dynamics data shall be consistent with the reported steady-state (power flow) data supplied per Reliability Standard MOD-010~~-0~~– Requirement1.

R2. The Regional Reliability Organization shall participate in the documentation of its Interconnection's data requirements and reporting procedures and, shall participate in the review of those data requirements and reporting procedures (at least every five years), and shall provide those data requirements and reporting procedures to Regional Reliability Organizations, NERC, and all users of the Interconnected systems on request (within five business days).

C. Measures

M1. The Regional Reliability Organizations within each Interconnection shall have documentation of their Interconnection's dynamics data requirements and reporting procedures and shall provide the documentation as specified in ~~Reliability Standard~~ MOD-013-0_R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

Data requirements and reporting procedures: on request (5 business days).

Periodic review of data requirements and reporting procedures: at least every five years.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Data requirements and reporting procedures for dynamics data were provided, but were incomplete in one of the five areas defined in ~~Reliability Standard~~ MOD-013-0_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Data requirements and reporting procedures provided were incomplete in two or more of the five areas defined in ~~Reliability Standard~~ MOD-013-0_R1.

2.4. Level 4: Data requirements and reporting procedures for dynamics data were not provided, or the data requirements and reporting procedures provided were incomplete in three or more of the five areas defined in ~~Reliability Standard~~ MOD-013-0_R1.

E. Regional Differences

1. None.

Version History

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

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 the Version 0 MOD-016 modified to include a translation of planning measure II.D.M2, 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 second draft of the standard to be posted for industry comment from October 15 – November 30, 2005.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Review comments from industry posting; post consideration of comments.	December 1 – January 15, 2006
2. Post standards and implementation plan for 30-day pre-ballot review.	February 1 – March 2, 2006
3. Conduct 1st ballot.	March 5-15, 2006
4. Consider comments submitted with 1st ballot; post consideration of comments	March 15 – March 20, 2006
5. Conduct 2nd ballot.	March 20 – 30, 2006
6. Post standards and implementation plan for 30-day review by Board.	April 1, 2006
7. Board adoption date.	May 1, 2006
8. Proposed Effective date.	November 1, 2006

Definitions of Terms Used in Standard

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No definitions are introduced in this standard.

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-016-1

3. **Purpose:** Ensure that accurate, actual Demand data is available to support assessments and validation of past events and databases. Forecast 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 information related to controllable Demand-Side Management (DSM) programs is needed.

4. **Applicability:**

   4.1. Planning Authority.

   4.2. Regional Reliability Organization.

5. **Proposed Effective Date:** November 1, 2006

B. Requirements

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.

- **R1.2.** The data submittal requirements shall stipulate that the Load-Serving Entity count each customer demand within its service territory once and only once, on an aggregated and dispersed basis, in developing its actual and forecast customer demand values.

R2. The Regional Reliability Organization shall distribute its documentation required in MOD-016 R1 for reporting customer Demand data and any changes to that documentation, to all Planning Authorities that work within its Region within 30 calendar days of approval.

R3. The Planning Authority shall distribute its documentation required in MOD-016 R1 for reporting customer Demand data and any changes to that documentation, to its Transmission Planners and Load-Serving Entities that work within its Planning Authority Area within 30 calendar days of approval.

C. Measures

M1. The Regional Reliability Organization's documentation for actual and forecast customer Demand data shall contain all items identified in MOD-016 R1.

M2. The Regional Reliability Organization shall have evidence it provided its actual and forecast customer Demand data reporting requirements within 30 calendar days of approval to each Planning Authority that works within its Region.

M3. The Planning Authority shall have evidence it provided documentation for reporting customer Demand data and any changes to that documentation to its Transmission Planners and Load-Serving Entities as required in MOD-016 R3.

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

One calendar year.

1.3. Data Retention

For the Regional Reliability Organization and Planning Authority: Current version of the documentation.

For the Compliance Monitor: Three years of audit information.

1.4. Additional Compliance Information

The Regional Reliability Organization and Planning Authority 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

2.1. Level 1: Documentation does not address completeness and double counting of customer data.

2.2. Level 2: Documentation did not address one of the three types of data required in MOD-016 R1 (Demand data, Net Energy for Load data, and controllable DSM data).

2.3. Level 3: No evidence documentation was distributed as required.

2.4. Level 4: Either the documentation did not address two of the three types of data required in MOD-016 R1 (Demand data, Net Energy for Load data, and controllable DSM data) or there was no documentation.

E. Regional Differences

1. None identified.

Version History

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

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 measures 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.
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Future Development Plan:

Anticipated Actions	Anticipated Date
1. Consider comments on 2nd draft	To be determined
2. Conduct field test	To be determined
3. Revise standard based on field test results	To be determined
4. Post field test results and revised standard for comment	To be determined
5. Respond to comments	To be determined
6. Post revised standard for 30-day pre-ballot review	To be determined
7. Ballot standard	To be determined
8. Post standard for 30-day BOT review	To be determined
9. BOT adoption	To be determined
10. Effective date	To be determined.

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No new definitions are proposed for this standard.

A. Introduction

1. **Title:** **Verification of Models and Data for Generator Excitation System Functions**

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

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

4. **Applicability**

   4.1. Regional Reliability Organization.

   4.2. Generator Owner.

5. **Proposed Effective Date:** To be determined.

B. Requirements

R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of models and data associated with generator excitation system functions including voltage regulator controls, 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, engineering analysis, field verification of equipment settings, testing, simulation and comparison with test results or disturbance monitoring data, etc.

R1.3. Periodicity and schedule of verification and reporting, including schedules associated with field changes to existing units, and refurbished units.

R1.4. Information to be reported related to generator excitation system functions:

R1.4.1. Verified manufacturer and type of excitation system/voltage regulator control system (static, brushless, rotating, etc.).

R1.4.2. Verified model for each excitation system/voltage regulator control system with associated gains, time constants, and limits.

R1.4.3. Verified static set points for under and over excitation limiters.

R1.4.4. Verified line drop compensator settings.

R1.4.5. Open circuit test response data showing generator field voltage and generator terminal voltage (exciter field voltage and current data for brushless units).

R1.4.6. Verified model for each power system stabilizer with associated gains, time constants, and limits.

R1.4.7. Method of verification, including the date of verification, with the voltage regulator in the automatic voltage control mode.

R2. The Regional Reliability Organization shall provide its generator excitation system data verification and reporting procedures, and any changes to those procedures, 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 procedures for verifying and reporting its models and data associated with generator excitation system functions per MOD-026 R1.

C. Measures

M1. The Regional Reliability Organization shall have available for inspection a procedure for the verification and reporting of models and data associated with its generator excitation system functions in accordance with MOD-026 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 verification of the models and data associated with its generator excitation system functions, consistent with the Regional Reliability Organization procedure to the Regional Reliability Organization, and appropriate Transmission Planner and Planning Authority.

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 (To be added following field testing.)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

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 measures 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 from 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.

Description of Current Draft:

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

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Consider comments on 2nd draft	To be determined
2. Conduct field test	To be determined
3. Revise standard based on field test results	To be determined
4. Post field test results and revised standard for comment	To be determined
5. Respond to comments	To be determined
6. Post revised standard for 30-day pre-ballot review	To be determined
7. Ballot standard	To be determined
8. Post standard for 30-day BOT review	To be determined
9. BOT adoption	To be determined
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 of Generator Unit Frequency Response**

2. **Number:** MOD-027-1

3. **Purpose:** To provide verification of generator unit frequency response (other than Automatic Generation Control) for use in models for reliability studies.

4. **Applicability**

   4.1. Regional Reliability Organization.

   4.2. Generator Owner.

5. **Proposed Effective Date:** 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 (up to 30 seconds). 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, engineering analysis, field verification of equipment settings, testing, simulation and comparison with test results or disturbance monitoring data, etc.

R1.3. Periodicity and schedule of verification and reporting, including schedules associated with field changes to existing units, and refurbished units.

R1.4. Information to be reported related to generator unit frequency response:

R1.4.1. Verified manufacturer and type of speed governor controls.

R1.4.2. Verified model for each speed governor control with any associated deadband, gains, time constants, and limits (e.g., maximum valve opening velocity, maximum capability of the turbine, etc.).

R1.4.3. Verified frequency response data of the unit, considering additional plant controls that affect the response of the unit (blocked or nonfunctioning governors or modes of operation that limit frequency response).

R1.4.4. Method of verification and conditions of the verification including status of controls.

R2. The Regional Reliability Organization shall provide its frequency response verification and reporting procedures, and any changes to those procedures, 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 its generator unit frequency response per MOD-027 R1.

C. Measures

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 the information required in MOD-027 R1 regarding its generator frequency response.

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 (To be added, following field testing.)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

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 the Version 0 VAR-001 modified to include a translation of planning measures III.C.M1, III.C.M2 and III.C.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 from 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.

Description of Current Draft:

This is the second draft of the standard to be posted for industry comment from October 15 through November 30, 2005.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Review comments from industry posting; post consideration of comments.	December 1 – January 15, 2006
2. Post 3rd draft of standards and implementation plan for 45 day review.	January 15 – February 28, 2006
3. Review comments from industry posting; post consideration of comments.	March 1 – April 1, 2006
4. Post standards and implementation plan for 30-day pre-ballot review.	April 15 – May 15, 2006
5. Conduct 1st ballot.	May 20 – 30, 2006
6. Consider comments submitted with 1st ballot; post consideration of comments	June 1-18, 2006
7. Conduct 2nd ballot.	June 19-29, 2006
8. Post standards and implementation plan for 30-day review by Board.	July 1-30, 2006
9. Board adoption date.	August 1, 2006
10. Proposed Effective date.	February 1, 2007

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:** **Voltage and Reactive Control**
2. **Number:** VAR-001-1
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.** Purchasing-Selling Entities
5. **Proposed Effective Date:** February 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.

R2. The Transmission Operator shall specify criteria that exempt generating units from compliance with the requirements defined in VAR-001 R5, and VAR-001 R7.1.

R3. Each Transmission Operator shall acquire sufficient reactive resources within its area to protect the voltage levels under normal and Contingency conditions. This includes the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.

R4. Each Transmission Operator shall maintain a list of synchronous generators in its area that are exempt from following a voltage or Reactive Power schedule. For each generator that is on this exemption list, the Transmission Operator shall notify the associated Generator Owner.

R5. Each Transmission Operator shall specify a voltage or Reactive Power schedule to be maintained by each non-exempt synchronous generator. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator.

R6. Each Purchasing-Selling Entity shall arrange for (self-provide or purchase) reactive resources to satisfy its reactive requirements identified by its Transmission Service Provider.

R7. The Transmission Operator shall know the status of all transmission Reactive Power resources, including the status of voltage regulators and power system stabilizers.

R7.1. When notified of the loss of an automatic voltage regulator control, the Transmission Operator shall direct the Generator Operator to maintain or change either its voltage schedule or its Reactive Power schedule.

R8. The Transmission Operator shall be able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow.

R9. 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 within established limits.

R10. Each Transmission Operator shall maintain reactive resources to support its voltage under first Contingency conditions.

R10.1. Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when Contingencies occur.

R11. 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.

R12. After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes.

R13. The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.

C. Measures

M1. The Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule that meets the criteria specified in VAR-001 R5 to each Generator Operator it requires to follow such a schedule.

M2. The Transmission Operator shall have evidence to show that, for each generating unit in its area that is exempt from following a voltage or Reactive Power schedule, the associated Generator Owner was notified of this exemption.

M3. The Transmission Operator shall have evidence to show that it issued directives as specified in VAR-001 R 7.1 when notified by a Generator Operator of the loss of an automatic voltage regulator control.

M4. The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap change in accordance with VAR-001 R11.

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: No documentation to show that owners of generating units that are exempt from following voltage or Reactive Power schedules were notified of this exemption.

2.2. Level 2: There shall be a level two non-compliance if either of the following conditions exists:

2.2.1 No documentation to show that directives were issued in accordance with VAR-001 R7.1.

2.2.2 No evidence that documentation was provided to Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with VAR-001 R11.

2.3. Level 3: Voltage or Reactive Power schedules do not exist for all generating units required to follow the schedules.

2.4. Level 4: No evidence voltage or Reactive Power schedules were provided to Generator Owners.

D. Regional Differences

None identified.

Version History

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

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 measures III.C.M2, III.C.M4, and III.C.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 from 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.

Description of Current Draft:

This is the second draft of the standard to be posted for industry comment from October 15, 2005 through November 30, 2005.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Review comments from industry posting; post consideration of comments.	December 1 – January 15, 2006
2. Post 3rd draft of standards and implementation plan for 45 day review.	January 15 – February 28, 2006
3. Review comments from industry posting; post consideration of comments.	March 1 – April 1, 2006
4. Post standards and implementation plan for 30-day pre-ballot review.	April 15 – May 15, 2006
5. Conduct 1st ballot.	May 20 – 30, 2006
6. Consider comments submitted with 1st ballot; post consideration of comments	June 1-18, 2006
7. Conduct 2nd ballot.	June 19-29, 2006
8. Post standards and implementation plan for 30-day review by Board.	July 1-30, 2006
9. Board adoption date.	August 1, 2006
10. Proposed Effective date.	August 1, 2007

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 applicable Facility Ratings to protect equipment and the reliable operation of the Interconnection.

4. **Applicability**

   4.1. Generator Operator.

   4.2. Generator Owner.

5. **Proposed Effective Date:** August 1, 2007

B. Requirements

R1. The Generator 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.

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the synchronous generator voltage or Reactive Power output (within applicable Facility Ratings) as directed by the Transmission Operator.

R2.1. 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 Power schedule directed by the Transmission Operator.

R3. Each Generator Operator shall notify its associated Transmission Operator within 30 minutes of any of the following. If unable to notify the Transmission Operator within 30 minutes, the Generator Operator shall have documentation to support the reasons for not making the notification within 30 minutes.

R3.1. A status change on any synchronous generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer.

R3.2. A status change on any other Reactive Power resources under the Generator Operator's control.

R3.3. A voltage or Reactive Power schedule for a generator is not maintained.

R4. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.

R4.1. For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:

R4.1.1. Tap settings.

R4.1.2. Available fixed tap ranges.

R4.1.3. Impedance data.

R4.1.4. The +/- voltage range with step-change in % for load-tap changing transformers.

R5. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, equipment, or regulatory or statutory requirements.

R5.1. If the Generator Operator can't comply with the Transmission Operator's specifications, the Generator Operator shall notify the Transmission Operator and shall provide the associated reason.

C. Measures

M1. The Generator Operator shall have evidence to show that it received approval of its associated Transmission Operator any time it failed to operate a synchronous generator in the automatic voltage control mode.

M2. The Generator Operator shall have evidence to show that it controlled its generator voltage and reactive output to meet the voltage or Reactive Power schedule provided by its associated Transmission Operator.

M3. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any of the changes identified in VAR-002 R3.1 through R3.3.

M4. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up transformers and auxiliary transformers as required in VAR-002 R4.1.1 through R4.1.4

M5. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation as required in VAR-002 R5.

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 evidence needed for VAR-002 M1 through M3 for a rolling 12 months.

The Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers.

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

1.4. Additional Compliance Information

The Generator Owner and Generator Operator 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 Generator Operator

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

2.1.1 Failed to meet the voltage or Reactive Power schedule, subsequent to the 30-minute notification period, for an accumulated time of 8 or less unit-hours for an individual generator without Transmission Operator approval.

2.1.2 Operated without automatic voltage regulator control for 8 or less unit-hours for an individual generator without Transmission Operator approval.

2.1.3 One incident of failing to notify the Transmission Operator within 30 minutes of one of the status changes identified in VAR-002 R3.1 through R3.3.

2.2. **Level 2:** There shall be a Level 2 non-compliance if either of the following conditions exist:

2.2.1 Failed to meet the voltage or Reactive Power schedule, subsequent to the 30-minute notification period, for an accumulated time of more than 8 but less than 16 unit-hours for an individual generator without Transmission Operator approval.

2.2.2 Operated without automatic voltage regulator control for more than 8 unit-hours but less than 16 unit-hours for an individual generator without Transmission Operator approval.

2.2.3 More than one but less than 5 incidents of failing to notify the Transmission Operator within 30 minutes of one of the status changes identified in VAR-002 R3.1 through R3.3.

2.3. **Level 3:** There shall be a Level 3 non-compliance if any of the following conditions exist:

2.3.1 Failed to meet the voltage or Reactive Power schedule, subsequent to the 30-minute notification period, for an accumulated time of 16 or more but less than 24 unit-hours for an individual generator without Transmission Operator approval.

2.3.2 Operated without automatic voltage regulator control for more than 24 unit-hours for an individual generator without Transmission Operator approval.

2.3.3 More than 5 but less than 10 incidents of failing to notify the Transmission Operator within 30 minutes of one of the status changes identified in VAR-002 R3.1 through R3.3.

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

2.4.1 Failed to meet the voltage or Reactive Power schedule, subsequent to the 30-minute notification period, for an accumulated time of more than 24 unit-hours for an individual generator without Transmission Operator approval.

2.4.2 Operated without automatic voltage regulator control for more than 24 unit-hours for an individual generator without Transmission Operator approval.

2.4.3 Ten or more incidents of failing to notify the Transmission Operator within 30 minutes of one of the status changes identified in VAR-002 R3.1 through R3.3.

3. Levels of Non-Compliance for Generator Owner:

3.1.1 **Level One:** Not applicable.

3.1.2 **Level Two:** Documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage was missing two of the data types identified in VAR-002 R4.1.1 through R4.1.4.

3.1.3 **Level Three:** No documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage

3.1.4 **Level Four:** Did not ensure generating unit step-up transformer settings were changed in compliance with the specifications provided by the Transmission Operator.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

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 from 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.

Description of Current Draft:

This is the second draft of the standard to be posted for industry comment from October 15 through November 30, 2005.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Review comments from industry posting; post consideration of comments.	December 1 – January 15, 2006
2. Post 3rd draft of standards and implementation plan for 45 day review.	January 15 – February 28, 2006
3. Review comments from industry posting; post consideration of comments.	March 1 – April 1, 2006
4. Post standards and implementation plan for 30-day pre-ballot review.	April 15 – May 15, 2006
5. Conduct 1st ballot.	May 20 – 30, 2006
6. Consider comments submitted with 1st ballot; post consideration of comments	June 1-18, 2006
7. Conduct 2nd ballot.	June 19-29, 2006
8. Post standards and implementation plan for 30-day review by Board.	July 1-30, 2006
9. Board adoption date.	August 1, 2006
10. Proposed Effective date.	August 1, 2007

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 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:** August 1, 2007

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.

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 a Reactive Power resource assessment annually unless changes in system conditions do not warrant such analysis. The Transmission Planner and Planning Authority shall each conduct Reactive Power resource assessments at least once every five years.

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 upon request.

C. Measures

M1. The Transmission Planner and Planning Authority shall each have evidence that it developed 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 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 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 latest 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 conducted but did not consider known changes in system conditions that may affect system reliability.

2.3. Level 3: Not applicable.

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

2.4.1 No method and criteria for assessing adequate static and dynamic Reactive Power requirements.

2.4.2 No evidence of an assessment of static and dynamic Reactive Power requirements within the past 5 years.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

Background:

The Phase III & IV drafting team thanks all commenters who submitted comments on the second draft of the standards included in Set Two of the Phase III & IV Standards. Set Two of the Phase III & IV Standards was posted for a second public comment period from October 17 through December 3, 2005. The SDT asked industry participants to provide feedback on the standards through a special Standard Comment Form. There were 36 sets of comments, including comments from more than 146 different people 6 of the 9 Industry Segments, and all NERC Regions as shown in the table on the following pages.

After careful review and consideration of the comments received, the drafting team believes that the following standards have reached stakeholder consensus. The drafting team will post these standards for a 30-day pre-ballot review:

____ standards have not reached stakeholder consensus, and these have been modified based on stakeholder comments and will be posted for an additional comment period:

The Standards Authorization Committee (SAC) directed the drafting team to field test two of the standards in Set One of Phase III & IV:

- MOD-026-1 — Verification of Generator Excitation Systems and Voltage Control Model Data
- MOD-027-1 — Verification and Status of Generating Unit Frequency Response

The drafting team will post a description of the field tests as soon as they are approved.

Informational versions of MOD-026 and MOD-027 have been posted so stakeholders can see the changes made based on comments submitted during the second comment period.

This 'Consideration of Comments' document includes the comments on the standards that are in 'Set Two' and they are listed in the Index on the following pages.

In this document, stakeholder comments have been organized so that it is easier to see the summary of changes being requested of each standard. The comments can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Phase-III-IV.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Director of Standards, Gerry Cauley at 609-452-8060 or at gerry.cauley@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

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

Legend:

Groups that submitted comments:

(G1) - TVA
(G2) - WECC Loads and Resources Subcommittee
(G3) - SERC EC Planning Standards Subcommittee
(G4) - SERC Operations Planning Subcommittee
(G5) – Southern Co Services
(G6) – Southern Co Generation
(G7) - Midwest Reliability Organization
(G8) – NPCC CP9, Reliability Standards Working Group
(G9) – Pepco Holdings Inc Affiliates
(G10) – ISO/RTO Council
(G11) – WECC Reliability Subcommittee
(G12) - FRCC

Industry Segments:
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 Gv't Entities

(I) – Indicates that a set of comments was submitted individually in addition to submitting comments as part of a group

Commenter	Organization	1	2	3	4	5	6	7	8	9
Bill Shemley (G8)			x							
Mike Green (G3)	AEC	x								
Anita Lee (G10)	AESO		X							
Darrell Pace (G3)	AL Electric Coop	x								
Ken Goldsmith (G7)	ALT									
Kirit Shah	Ameren - Transmission Issues Subcommittee									
John E. Sullivan	Ameren	x								
Peter Burke	ATC	x								

Scott Waples (G11)	Avista									
Thomas Fung	BCTC		x							
Dave Rudolph (G7)	BEPC									
Mary Johannis (G2)	BPA	x								
Lynn Aspaas	BPA	x		x		x	x			
Rebecca Berdahl (G11)	BPA	X								
Chuck Matthews (G11)	BPA	x								
Rebecca Berdahl	BPA – Pwr Business Line			x		x	x			
Phil Park (G11)	Britiish Columbia TC			x						
Lisa Szot (G10)	CAISO		X							
Grace Anderson (G2)	CEC									x
Mike Jaske (G2)	CEC									x
Jesus Moya Vazquez	CFE	x		x		x				
Karl Kohlrus	City Water, Light & Power					x				
Bob Remley (G12)	Clay Electric			X						
Bob Kotecha (G8)	ConEd	x								
John K. Loftis, Jr.	Dominion – Elec Trans	x								
Brian Moss (G3) (G4)	Duke Power	x								
Don Reichenbach (G4)	Duke Power	X								
Greg Mason	Dynegy Generation					x				
Kham Vongkhamchanh (G3)	Entergy	x								

Uma Gangadharan (G4)	Entergy	x								
Melinda Montgomery (G4)	Entergy	X								
Sam Jones (G10)	ERCOT		X							
Bill Bojorquez	ERCOT – Standards Evaluation Subcommittee		x							
Ray Morella	FirstEnergy	x								
Bob Schoneck (G12)	FPL			x						
John Shaffer (G12)	FPL	X								
John Odom (G12)	FRCC		x							
Linda Campbell (G12)	FRCC		x							
Dick Pursley (G7)	GRE									
David Kiguel (G8)	Hydro One	x								
Roger Champagne	Hydro-Québec TransÉnergie	x								
Ron Schelberg (G11)	Idaho Power Co	x								
Ron Falsetti (G10) (I)	IESO		X							
Rick Haener (G2)	IPC	x								
Pete Brandien (G10)	ISO-NE		x							
Kathleen Goodman (G8) (I)	ISO-NE		x							
Greg Woessner (G12)	Kissimmee Utility Authority			X						
Mace Hunter (G12)	Lakeland				x					
Paul Elwing (G12)	Lakeland Electric					x				

Dennis Florom (G7)	LES									
Mo Beshir (G11)	Los Angeles DWP	x								
Shashi Parehk (G8)	MA Dept. Tele. & Elec.									x
John Horakh	MAAC		x							
Mark Kuras	MAAC		X							
Jerry Tang (G4)	MEAG	X								
David Weekley (G3)	MEAG Power	x								
Tom Mielnik (G7)	MEC									
Robert Coish (G7)	MHEB									
Terry Bilke (G7)	MISO		X							
Bill Phillips (G10)	MISO		x							
Joe Knight (G7)	MRO		x							
Peter Lebro (G8)	Nat'l Grid	x								
Julie Reichle (G11)	Northwestern	x								
Guy Zito (G8)	NPCC		X							
Alan Boesch (G7)	NPPD	X								
Dave Little (G8)	NS Power	x								
John Leland (G2)	NWE	X								
Greg Campoli (G8)	NYISO		x							
Mike Calimano (G10)	NYISO		x							
Ralph Rufrano (G8)	NYPA	x								

Al Adamson (G8)	NYSRC		x							
Todd Gosnell (G7)	OPPD									
Tom Washburn (G12)	OUC			X						
Ben Morris (G11)	Pacific Gas and Electric	x								
Michael Sidiropoulos (G11)	PacifiCorp	x								
Phil Creech (G4)	PEC	x								
James Newton (G9)	Pepco Energy Services						x			
Richard J. Kafka (G9)	Pepco Holdings	X								
Steve Crutchfie (G4)ld	PJM		x							
Bruce Balmat (G10)	PJM		x							
Mahendra Patel	PJM - Wind Generation Task Force		x							
David Thorne (G9)	Potomac Electric Pwr Co	x								
Michael Pfeister	Salt River Project	x								
Brian Keel (G11)	Salt River Project	x								
Mohan Kondragunta	SCE	x								
Clay Young (G3)	SCE&G			x						
Gene Delk (G4)	SCEG	x								
Art Brown (G3)	SCPSA	x								
William Gaither (G4)	SCPSA	x								
Steve Wallace (G12)	Seminole Electric Cooperative				x					

Garl Zimmerman (G12)	Seminole Electric Cooperative				x					
Carter Edge (G4)	SEPA				X					
Pat Huntley (G3)	SERC		x							
Susan Morris (G4)	SERC		x							
Craig Cameron (G11)	SMUD									
Doug McLaughlin (G4)	SOCO	X								
Mohan Kondragunta (G11)	Southern CA Edison	x								
Roman Carter (G6)	Southern Co Generation					X				
Thomas A. Higgins (G6)	Southern Co Generation					X				
Joel Dison (G6)	Southern Co Generation					X				
Wayne Moore (G6)	Southern Co Generation					x				
Bob Jones (G3)	Southern Co Services									
Marc Butts (G5)	Southern Co Services	x								
Dan Baisden (G5)	Southern Co Services	X								
James Busbin (G5)	Southern Co Services	X								
Wade Pugh (G5)	Southern Co Services	X								
Keith Calhoun (G5)	Southern Co Services	X								
James Ford (G5)	Southern Co Services	X								
Mike Oatts (G5)	Southern Co Services	X								
Doug McLaughlin (G5)	Southern Co Services	X								
Dean Ulch (G5)	Southern Co Services	X								

Jim Viikinsalo (G5)	Southern Co Services	X								
Phil Winston (G5)	Southern Co Services	X								
Rodney O’Bryant (G5)	Southern Co Services	X								
Jim Griffith (G5)	Southern Co Services	X								
Steve Williamson (G5)	Southern Co Services	X								
Monroe Landrum (G5)	Southern Co Services	X								
Raymond Vice (G5)	Southern Co Services	X								
Terry L. Crawley (G6)	Southern Nuclear					X				
Charles Yeung (G10)	SPP		x							
Alan Gale (G12)	Tallahassee Electric				x					
Roger Champagne (G8)	TE	x								
Jerry Nicely (G1)	TVA					x				
Mark Marcum (G1)	TVA					x				
Dennis Chastain (G1)	TVA	x								
David Marler (G1)	TVA	x								
David Thompson (G1)	TVA					x				
Bob Millard (G1)	TVA	x								
Meredith Snyder (G1)	TVA	x								
Jim Whitehead (G1)	TVA	x								
Travis Sykes (G3)	TVA	x								
David Till (G3)	TVA	x								

Larry Goins (G4)	TVA	X								
Mike Clements (G4)	TVA	X								
Karl A Bryan	US Army Corps of Engineers					x				
Jay Seitz	US Bureau of Reclamation					x				
Darrick Moe (G7)	WAPA									
Leonard York (G11)	WAPA	x								
Mariam Mirzadeh (G11)	WAPA-SNR	x								
Howard Rulf	We Energies			x	x	x				
Jay Loock (G2)	WECC		X							
Dick Simons (G2)	WECC		x							
Steve Ruekert (G11)	WECC		x							
Jim Maenner (G7)	WPS									
Pam Oreschnick (G7)	XCEL									
Jim Whitaker (G11)	Xcel Energy	x								

Index to Questions, Comments and Responses:

1. Please identify anything you believe needs to be modified before EOP-005 is balloted:

EOP-005-1 — System Restoration Plans (Modified Version 0)

Summary Consideration:

Commenter	Comment
FRCC (G12)	Delete references to Attachment 1 in R1, D2.2 and D2.4.1 (since Attachment 1 has been removed)
Response:	
FirstEnergy Raymond Morella	The standard is acceptable as written. It is assumed that Attachment 1-EOP-005-1 remains unchanged as it was not provided.
Response:	
Mid-Atlantic Area Coordinating Council John Horakh	The IV.A.M2 and M3 material should NOT be moved to a new Version 1 Standard. Material that is closely related should be kept together as much as possible. I assume the EOP-005-1 Attachment 1 will be the same as the EOP-005-0 Attachment 1. That was not made clear and the Attachment was not included with the Standards as posted. Cranking Path information to be provided (R9 and M2) should be transmitted by a secure method and kept in a secure location. Should that be specified in the Standard?
Response:	
Pepco Holdings, Inc. Affiliates (G9)	PJM requires annual testing of black start units. This does not appear to be unduly burdensome and gives greater assurance of successful black start when required. Fives years is a very long time for units that may not run otherwise. PHI assumes that Attachment 1 (of EOP-005-0) still applies - it should be included in the package.
Response:	
U.S. Army Corps of Engineers Karl Bryan	1. ll references to simulated testing for blackstart should be changed so that only actual testing is performed. Or, at a minimum require blackstart testing to be performed once every 5 years. There is no guarantee that the generating facilities will be able to provide line charging necessary to blackstart the grid and/or pick up the load blocks as identified in the restoration plan. At present blackstart testing is required for blackstart listed facilities, but this blackstart testing is only verifying that the generating facility can energize its own internal powersystem. The proof of the pudding would be for the generating facility to energize a piece of the grid and then to pick up load commensurate with the blocks of load that the system restoration plan says the facility would be expected to pick up. Allowing simulation of the blackstart testing of the grid is like starting a car, the engine starts but that is no guarantee that the car can be driven, especially if the transmission is not connected to the engine. 2. A requirement for developing blackstart agreements between the transmission operator and the generator owner needs to be added. It amazes me how often the restoration plans refer to a blackstart generator and yet the owner/operator of the generator isn't aware that they are even on a blackstart list let alone what role they play in system restoration. Also, how quickly blackstart is required needs to be a part of the agreement. My organization is

Commenter	Comment
	looking at remote operating some facilities identified as blackstart generating facilities and the time to blackstart will be close to 2 hours. The system restoration plan developers don't have a time requirement listed for blackstarting. Economics is driving the remoting of the facilities and if blackstarting is required then the cost for the blackstart asset needs to be paid for. 3. A requirement for developing cranking path agreements between the transmission operator and the generator owner/operato needs to be added. 4. There should also be additional Measures for: a. Transmission operator provide documentation of blackstart agreements with the generator owner that has been identified as a blackstart generator. b. Transmission operator should provide test results for verifying that the pieces of the system restoration plan are capable of being performed by the blackstart generators. c. Transmission operator provide documentation of cranking path agreements with the generator owners of generating facilities that are identified as cranking path resources (generators).
Response:	
SERC Operations Planning Subcommittee (G4)	Remove the word "availability" from R8 in EOP-005-1. This concept is already addressed in EOP-007-0 in the Regional BCP. Availability is an operating consideration rather than a discrete data element. Incorporating IVAM2 and IVAM3 into EOP-005 is sufficient. There is no need for a new Standard.
Response:	
Dynegy Generation Greg Mason	1.R8. The term "availability" needs to be omitted or clarified. Should the term "reliability" be used instead? How will the Transmission Operator verify/judge the availability or reliability of a unit for blackstart other than the results of the blackstart tests already specified in R10? 2. R10. This section needs to clarify the term "intended function." If this term means actually testing or simulating the starting of a larger and perhaps remote unit from a blackstart unit,then the Transmission Owner should be required to obtain the Generation Owner's concurrence on any such test because of the risk to plant equipment during a test. 3.R10.1 This section should be modified to require this simulation or testing be completed at least once every five years, unless the Transmission Owner can verify that system conditions that would impact the test/simulation have not substantially changed in the last five years.
Response:	
U.S Bureau of Reclamation Jay Seitz	1. This standard lists 11 requirements and several sub-requirements (20 in all). However there are only 2 measurements described. The standard should be drafted such that for each requirement there is a defined, documented measure. And each measure should cite which requirement it assesses. 2. We believe the number of requirements for this standard could be greatly distilled. For example the bulk of the standard could be comprised of two requirements: R1 the requirement to develop the restoration plan and all the components required of that plan; and R2 the requirement to prove and document that the plan works. Then, two measurements would follow: one to assess the contents of the plan and one to assess the simulation or testing of

Commenter	Comment
	the plan. 3. Additional requirements, such as testing communication systems and performing and documenting training exercises, should each have a corresponding measure. 4. R8 of the draft deals with the capabilities of the generating unit. The length of time for the unit to be blackstarted should also be addressed. Although a unit may be blackstart capable it may take an inordinate amount of time to start the unit. The starting time expectations of the plan should be vetted by the generator owner. 5. As part of the restoration plan the transmission operator shall also have documented that the generator owner is aware of the plan, aware of the generator's role, and agrees to participate.
Response:	
PJM Interconnection, L.L.C. Mark Kuras	Compliance elements need to be developed for all the requirements in this standard. Standards should not be revised piecemeal. These added requirements are in the right place in this Standard but the entire Standard needs to be revised not just a small part added. There is no Attachment 1 to review. In 2.4.1, remove …exists but… 2.4.2 can then be deleted. Add …were not provided… to the end of 2.4.3 and delete …No… at the beginning of 2.4.3.
Response:	
ISO/RTO COUNCIL (G10)	It is the IRC's view the standard needs to be developed to incorporate compliance elements for all requirements within the standard and NERC should avoid evolving / developing standards piecemeal. These added requirements are in the right place in this Standard but the entire Standard ought to be revised rather than adding small parts to it. Requirement R1 specifies that only the applicable elements of Attachment 1 need be included within the plan while the level 4 non-compliance is based on exclusion of two or more elements from the attachment. We recommend inclusion of …."applicable "…in the level 4 compliance level to be consistent.. We also suggests an appropriate definition or guidelines to be added to explain what constitutes "Applicable elements". In 2.4.1, remove …"exists but"… 2.4.2 can then be deleted. Add …"were not provided"… to the end of 2.4.3 and delete …"No"… at the beginning of 2.4.3. R7 The IRC suggests guidelines/clarification be provided to explain what constitutes "testing" or "simulation" of the restoration procedure. Is it intended that only simulations through the use of a simulator constitute compliance or will table top restoration plans exercises satisfy this requirement. R4. Should generators be included given that they are a key part for restoration plans? R5. Change to upper case for BA. "periodically" should be a more specific term i. e. yearly, etc. R8. and R10. They might be blended in one text. R10." ..through simulation .." Should be provided a definition for simulation? and if so, consider specifing to what extend. Also, Attachment 1 is not included for review.
Response:	
Dominion	(1) Revise R8. to be consistent with R1.1 of EOP-007. It should read: Each transmission operator shall provide the

Commenter	Comment
John Loftis SERC EC Planning Standards Subcommittee (G3)	name, location, megawatt capacity, type of unit, latest date of test, and starting method of the system blackstart generating units in the transmission operator's area to meet the regional requirement for maintaining a database. (2) If this recommendation is accepted, revise the reference to number, size, and location of blackstart units in M2 as appropriate.
Response:	
NERC Standards Evaluation Subcommittee Bill Bjorquez – ERCOT	1. The SES assumes the SDT is not recommending any revisions to Attachment 1-EOP-005-1 at this time. For the convenience of the reviewer, the SES recommends all drafting teams to include any attachments referenced to with the draft standard. 2. The SES recommends the SDT review the draft EOP-005-1 and capitalize all entity names and defined terms such as: Transmission Operators, Balancing Authorities, Reliability Coordinator, Cranking Path, etc. 3. R5 requires periodic testing of telecommunication facilities needed to implement the restoration plan. The SES believes the SDT should replace the term periodically with a stated term such as annually. 4. R6 requires the training of operating personnel in the implementation of the restoration plan, but provides little guidance as to how often or to what degree of scope this training shall incur. The SES recommends the SDT provide additional guideance as to this training requirement in order to make it a more effective and easier to measure. 5. R10 requires the Transmission Operator to demonstrate, either through simulation or testing, that the Blackstart generating units in its restoration plan can perform their intended functions. The SES notes that many Transmission Operators do not own or physically control generating units. Therefore, the SES would ask the SDT what obligation does the Generator Operator have in this testing? If there is an obligation, should it not be clearly stated in R10? 6. R10.1 requires the Transmission Operator to perform a simulation or test the blackstart units in its restoration plan at a minimum of five years. This is a long interval between tests for large, complicated, mechanical devices such as generators. SES recommends that this interval be consistent with Attachment 1-EOP-005-1. 7. The SES believes the Measures provided in the draft standard are a good starting point, but do not go far enough. For example in M2, the Transmission Operator is not specifically required to provide a copy of its plan to other entities unless requested. The SDT would agree, effective communication between entities is essential in service restoration; therefore, the SES recommends the SDT specifically state what entities are to receive the restoration documentation and include requirements, including a provision for updates as situations change.
Response:	
American Transmission Co. Peter Burke	There are some capitalization problems with all of the standards in this set in that the functional entities, such as Transmission Planner, Regional Reliability Coordinator, etc. should be capitalized consistantly throughout the standards. The industry should develop future standards for every generator to establish a blackout plan to improve coordination during an actual restoration event in addition to more specific standards applied to blackstart generators.
Response:	
Bonneville Power	Part of the Black Start Restoration Plan should include a requirement for an appropriate level of coordination with the

Commenter	Comment
Admin. – PBL Rebecca Berdahl	generation owner/operators that are sited in the plan. This coordination could be documented in the form of an agreement between the administrator of the Black Start Plan and the Generator Owners/Operators participating in the Plan. The coordination agreement should include items such as: identification of generator owner/operator facilities required to participate in the black start plan, when and how quickly a blackstart unit must respond, and what cranking path require energization.
Response:	
Independent Electricity System Operator Ron Falsetti	It is IESO's view the standard needs to be developed to incorporate compliance elements for all requirements within the standard and NERC should avoid evolving / developing standards piecemeal. Requirement R1 specifies that only the applicable elements of attachment 1 need be included within the plan while the level 4 non-compliance is based on exclusion of two or more elements from the attachment. We recommend inclusion of ….."applicable "…in the level 4 compliance level to be consistent.. The IESO also suggests an appropriate definition or guidelines be added to explain what constitutes "Applicable elements" R7 The IESO suggests guidelines/clarification be provided to explain what constitutes "testing" or "simulation" of the restoration procedure. Is it intended that only simulations through the use of a simulator constitute compliance or will table top restoration plans exercises satisfy this requirement.
Response:	
Southern Co Generation (G6)	Under Requirement 11.5, the requirement should be modified by removing — may — in the requirement and replacing with: The affected Transmission Operators shall not resynchronize the isolated area(s) with the surrounding area(s) until the following conditions are met. Additionally, we recommend deleting requirement 11.5.4. It does not seem reasonable or logical for a control area to be required to shed 5,000 MWs of load, for example, in order for their neighbor to reconnect 1,000 MWs of their own load.
Response:	
Southern Co Services (G5)	We feel that R11.5 should be reworded to change the operative word in the standard from -may- to -shall.- Furthermore, we feel that R11.5.1, R11.5.2, R11.5.3, and R11.5.4 can be eliminated and the necessary provisions of these standards placed in a more concise statement contained in R11.5. The reworded provision could possibly read as follows: The affected transmission operators shall not re-synchronize the isolated area(s) with the surrounding area(s) unless the voltage, frequency, and phase angle permit, the affected reliability coordinator(s) and the adjacent areas are notified, and reliability coordinator approval is given. We also feel that the training required under R6 should be clearly defined in terms of scope and degree. We feel that this standard is overbroad, vague, and does not provide training personnel with the ability to determine if the requirements of this standard have been met.
Response:	
British Columbia Transmission Corp. Thomas Fung	R3 says each transmission operator shall develop restoration plans with a priority of restoring the integrity of the Interconnection. BCTC is concern this requirement may hinder the transmission operators from restoring their own system to a robust state in order to interconnect with adjacent neighbor systems, and may in fact delay the restoration of the Interconnection. BCTC suggest R3 be revised as follows: Each transmission operator shall develop restoration plans

Commenter	Comment
	with a priority to restore the integrity of its own system in order to quickly restore the integrity of the Interconnection.
Response:	
Midwest Reliability Organization (G7)	The MRO does not believe that the non-compliance item listed in 2.3 should be level 3. The MRO believes it should be level 2 after comparing it with the the non-compliance item listed in 2.2.
Response:	
Tennessee Valley Authority (G1)	None
WECC Reliability Subcommittee (G11)	None
NERC Wind Generator Task force Mahendra Patel	The WGTF has no comments.
NPCC CP9, Reliability Standards Working Group (G8)	No comment.
Salt River Project Michael Pfeister	None
Hydro-Québec TransEnergie Roger Champagne	No comment.
City Water, Light & Power Karl Kohlrus	None
ISO New England, Inc. Kathleen Goodman	None
Bonneville Power Administration Lynn Aspaas	None
Southern California	None

Commenter	Comment
Edison Mohan Kondragunta	
Comision Electricidad de Federal (1, 3, 5) Jesus Moya Vazquez	None
Ameren John Sullivan	None
Tennessee Valley Authority (G1)	None
We Energies Howard Rulf	None

2. Please identify anything you believe needs to be modified before MOD-013 is balloted:

MOD-013-1 — Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures (Modified Version 0)

Summary Consideration:

Commenter	Comment
Mid-Atlantic Area Coordinating Council John Horakh	The Future Development Plans table shows a Proposed Effective Date of August 1, 2007, but I believe the intended date is February 1, 2007, as shown in other places.
Response:	
FirstEnergy Raymond Morella	The proposed effective date of the standard is not consistent throughout various references. The drafting team needs to correct and it is assumed the correct data is August 7, 2007.
Response:	
ISO New England, Inc. Kathleen Goodman	Drafting Team should match Proposed Effective Date with Anticipated Actions Date in this standard. MOD-012-0 should also be revised once MOD-013-1 is approved because MOD-013-0 requirements are referenced in MOD-012-0.
Response:	
American Transmission Co. Peter Burke	The standard has the same capitalization problems as were identified in EPO-005-01. The proposed effective dates that are used in the document are different throughout the standard (Anticipated Actions table, footer, and A.5) and need to be synchronized.
Response:	
Ameren John Sullivan	Will this reliability standard also apply to wind generators?
Response:	
ISO/RTO Council (G10) Independent Electricity System Operator Ron Falsetti	In our comments for MOD-028 (see below), we stated that some items were still required to be added to MOD-013, before MOD-028 could be retired. Our position remains the same.. The IRC disagrees with the drafting team's position that all the information within this standard is redundant and contained within MOD-012 & MOD-013, As an example, Requirement R2 (data has to be validated every five years) is not in the above noted standards. This requirement should be moved to MOD-013. With the above recommendation, MOD-028 could then be retired.
Response:	
Tennessee Valley Authority (G1)	R1.1 - Design Data needs to be defined. The requirement to provide design data at least one year prior to in-service-dates may be appropriate for new installations. However, some refurbishment scenario's may be completed in less

Commenter	Comment
	than one year, i.e., equipment failures, equipment damage, emergency type replacements. Therefore, this std. should provide consideration for those refurbishments that may be procured and installed within one year.
Response:	
Southern Co Generation (G6)	R1.1 - In practice, design data may not always be available one-year prior to the installation date. We recommend changing R1.1 to read: Design data shall be provided for new or refurbished excitation systems at the time the equipment is ordered with updated data provided once the unit is in service.
Response:	
FRCC (G12)	As written R1.1 is too restrictive for changes made to existing units and would delay implementation of new excitation systems on existing units. With budgeting and bidding requirements, this information may not be available 1 year before the in-service date. Remove the words "at least one year" from R.1.1 and add two new requirements R1.1.1 and R1.1.2. R1.1.1. For new units, design data shall be provided at least one year prior to the in-service date. R1.1.2. For refurbished units, design data shall be provided at least four months prior to the in-service date.
Response:	
Dynegy Generation Greg Mason	1.R1.1 This requirement is not practical as written. It will not always be feasible to provide new excitation system design data one year prior to the in-service date.Exceptions need to be provided for excitation system failures or other unforeseen circumstances. In those cases,the Generation Owner may temporarily install a backup system with little notice. In addition,the normal advance notice should be changed fron one year to 6 months to reflect more typical excitation system project timeframes. Also, suggest deleting the wording "other associated generation equipment" since it is vague and adds nothing to the "such as…" phrase.
Response:	
U.S Bureau of Reclamation Jay Seitz	The standard should be drafted such that for each requirement there is a defined, documented measure. And each measure should cite which requirement it assesses. Requirement R.1.2.2 requires unit-specific data for generators installed after 1990. the justification for this requirement is not clear. Data for sister units should be allowable regardless of the date of installation.
Response:	
U.S. Army Corps of Engineers Karl Bryan	R1.2.1 should allow the data from sister or identical units procured under the same contract in lieu of requiring unit specific data. Performing the required tests on identical units is not cost effective when you consider that the resulting data from identical units is well within the modelling parameter tolerances. Also, what is the justification for the 1990 cut off date for actual data vs. manufacturers data? The requirement that only unit specific data is acceptable for generators installed after 1990 means that each generator procured under the same contract would have to be individually tested even though the units are essentially identical. Requiring each unit to be tested seems to be a great waste of money and resources. Recommend that the last sentence of R1.2.1 be removed. There should be a measure for each requirement, otherwise how can you audit the requireme

Commenter	Comment
Response:	
NERC Standards Evaluation Subcommittee Bill Bjorquez – ERCOT	The SES recommends the SDT review the draft MOD-013-1 and capitalize all entity names such as: Regional Reliability Organization, Transmission Owners, Transmission Planners, etc. Also the SES recommends the SDT revise the Applicability section to include the named entities in R1 since each entity incurs some level of obligation to satisfying the standard. R1.2.1 states that estimated or typical manufacturer's dynamic data may be submitted to the RRO when unit-specific data cannot be obtained. The SES believes the best source of this data is actual testing. However, for the standard, the SES recommends the SDT give each RRO the discretion to determine if estimated or test-verified dynamic data is acceptable, including any year or size thresholds. R1.3, the terms static VAR controllers and static compensators are different terms for the same device. The SES believes the review of the data requirements and reporting procedures for this draft standard listed in R2 at five years is too long. The SES recommends this interval be 3 years.
Response:	
Bonneville Power Admin. – PBL Rebecca Berdahl	Recommend that the last sentence of R1.2.1 be revised or removed to account for generation owners procurement of multiple 'in-kind' generation equipment. This would eliminate needless and costly testing of generators procured under the same contract that perform to the same specs.
Response:	
Southern Co Services (G5)	We feel that under R1.2.1, the operative word -may- should be changed to -shall,- as -may- could imply that there is an option not to act.
Response:	
NERC Wind Generator Task force Mahendra Patel	The WGTF suggests that the standard drafting team clarify that R1.1 is applicable to wind generator plants (not individual wind generators). R1.2 should be clarified to refer to wind generator plants (not individual wind generators).
Response:	
SERC EC Planning Standards (G3)	1) In the Levels of Non-Compliance section, change R1 to Requirement 1 in sections 2.3 and 2.4. (2) Since design data generally will not be available one-year prior to the installation date, change R1.1 to read: Design data shall be provided for new or refurbished excitation systems at the time the equipment is ordered with updated data provided once the unit is in service.
Response:	
Dominion John Loftis	(1) In the Levels of Non-Compliance section, change R1 to Requirement 1 in sections 2.3 and 2.4. (2) Requirement R1.1 states: "Design data shall be provided for new or refurbished excitation systems at least one year prior to the in-service date with updated data provided once the unit is in service." The phrase "Design data" can be

Commenter	Comment
	interpreted many different ways, e.g. "the system is capable of continuously supplying 105% of the nominal rated current to the generator rotor, and 150% ceiling current for a minimum of 30 seconds; Ceiling voltage is based on 1.6 x rated field voltage; the excitation system is rated for the operating conditions of 40°C maximum ambient temperature with 90% non-condensing humidity", etc. are all part of the "Design data". Also, there should be some time limit to provide the final data once in service. Suggest that Requirement R1.1 be reworded as follows: "Dynamic model(s) with preliminary data shall be provided for new or refurbished excitation systems at least one year prior to the in-service date. "As-built" field data shall be provided within 90 days from actual in-service date."
Response:	
City Water, Light & Power Karl Kohlrus	None
Bonneville Power Administration Lynn Aspaas	None
Midwest Reliability Organization (G7)	None
Southern California Edison Mohan Kondragunta	None
PJM Interconnection, L.L.C. Mark Kuras	None
Salt River Project Michael Pfeister	None
Hydro-Québec TransEnergie Roger Champagne	No comment.
British Columbia Transmission Corp. Thomas Fung	None
WECC Reliability Subcommittee (G11)	None

Commenter	Comment
We Energies Howard Rulf	None
NPCC CP9, Reliability Standards Working Group (G8)	No comment.
Comision Electricidad de Federale Jesus Moya Vazquez	None
Pepco Holdings, Inc. Affiliates (G9)	None

3. Please identify anything you believe needs to be modified before MOD-016 is balloted:

MOD-016-1 — Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management (Modified Version 0)

Summary Consideration:

Commenter	Comment
Mid-Atlantic Area Coordinating Council John Horakh	The Future Development Plans table shows a Board Adoption Date of May 1, 2006 and a Proposed Effective Date of November 1, 2006, but I believe the intended dates are August 1, 2006 (Adoption) and February 1, 2007(Effective), as shown in other places.
Response:	
Pepco Holdings, Inc. Affiliates (G9)	Implementation date in draft standard is inconsistent with date shown in Implementation Plan.
Response:	
ISO New England, Inc. Kathleen Goodman	Drafting Team should match Proposed Effective Date in the standard with the Proposed Effective Date in the Implementation Plan. ISO NE recommends that R3 should read "The Planning Authority" instead of "regional reliability organization" to be consistent with M3.
Response:	
FRCC (G12)	In the title, purpose and R1, the term "Controllable Demand-Side Management" is used and is not a defined term. Either change it to "Direct Control Load Management", which is a defined term or define "Controllable Demand-Side Management"
Response:	
ISO/RTO Council (G10)	1. The drafting team should remember that this Standard deals with energy data along with demand data. Compliance elements need to be developed for all the requirements in this standard. Standards should not be revised piecemeal. These added requirements are in the right place in this Standard but the entire Standard should be revised rather than making a change to a small part of it.˜ 2. Requirement R1.1 should be revised to exclude references to specific standards but identify that consistent data is to used for all standards associated with adequacy and transmission assessments. Otherwise the Standard will need to be revised anytime that one of these referenced Standards is revised? For example, the Phase III & IV Standard Drafting Team is proposing that MOD-013-0 be revised and renumbered MOD-013-1. 3. Suggest replacing R1.1 with…"The documentation required in R1 shall ensure that consistent data is supplied for all NERC Reliability Standards where such data is required to be submitted or used for resource and transmission adequacy assessments."˜

Commenter	Comment
	4. In R1.2 change …"requirements"… to …"documentation required in R1"… to align better with R1. 5. R3 should read …"The planning authority shall distribute"… to be consistent to Measure M3. 6. In Section D, 2.3 change …"evidence"… to …"record that"… 7. R3 …"regional reliability organization"… should probably be …"planning authority"… 8. In R2 and R3, suggest deleting …"for reporting customer demand data, and any changes to that documentation,"… and changing …"of approval"… to …"of review or change and approval"… 9. M1 should read …"The regional reliability organization's documentation and the planning authority's documentation identified in Requirement 1 shall contain all items required." 10. M2 should read …"The regional reliability organization shall have records that it provided the documentation required in R1 within 30 calendar days of review or change and approval to each planning authority that works within its region." 11. M3 should read …"The planning authority shall have records that it provided the documentation required in R1 within 30 calendar days of review or change and approval to its transmission planners and load serving entities as required in requirement 3."
Response:	
WECC Reliability Subcommittee (G11)	Please see comments submitted by the WECC Loads and Resources Subcommittee.
Response:	
Southern California Edison Mohan Kondragunta	Please see comments submitted by the WECC Loads and Resources Subcommittee. (Jay Loock – WECC)
Response:	
WECC Loads and Resources Subcommittee (G2)	1. R1 uses the term controllable DSM, which is not in the NERC glossary of terms. A similar term – direct control load management – is in the NERC glossary, is this what is intended? 2. M2 uses term "evidence". This term is used loosely and needs clarification on what would classify as evidence (registered mail, email, etc). 3. One issue that presents a problem is that the term "controllable DSM" is not identified in the NERC Glossary and should not appear in R1. The terms Direct Control Load Management and Interruptible Demand, which are in the NERC Glossary, should be inserted in R1 in place of the term "controllable DSM." 4. Purpose: Ensure that accurate, actual demand data is available to support assessments and validation of past events and databases. Forecast 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, best available load information related to controllable demand-side management (DSM) programs is needed.

Commenter	Comment
	5. A clear definition of forecast demand is needed. Should the peak demand load forecasts include such factors as economic, demographic, and customer trends; conservation, improvements in the efficiency of electrical energy use, and other changes in the end uses of electricity; and weather effects? Should the peak demand load forecast have a 50% probability of not being exceeded (expected peak demand)? This load forecast is commonly referred to as the 1-in-2 peak load forecast. 6. 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. Transmission providers who serve customers who have retail access may have difficulty obtaining documentation identifying the scope and details of actual and forecast data. These transmission providers' can provide the actual and forecast data using their own data sets, but they may not have access to an individual retail choice customer's documentation for historical and forecast data. Often concerns about loss of competitive advantage or confidentiality issues are expressed about providing the data to the transmission provider. What is your solution to this issue in this Standard? 7. In R1, the definition of a load serving entity in the April 2005 NERC glossary seems to require that such entities make both generation and transmission services for end-use customers. Translating this to the version of LSE existing in California, it is not clear what is intended. Electricity service providers (ESP) make load forecasts and forward generation commitments for end-users, but they do not necessarily schedule load into the CAISO forward scheduling process. That function is performed by a scheduling coordinator. Given this institutional arrangement, would either of these be considered a load serving entity using the NERC definition? 8. In R1, the definition of a planning authority is unclear. Is the planning authority one that used to be considered synonymous with a control area operator, or is the planning authority those entities that prepare resource plans, transmission plans, etc. Again, in the context of the CAISO and the participating transmission owners (PG&E, SCE, SDG&E and some larger POUs) in the CAISO control area, which is the planning authority? 9. The proposed standard appears to make a change in current WECC L&R practices by dropping a requirement that non-firm load be identified. Is this intended? If so, why? If not, then the language of the requirement needs to be revised to also request projections of non-firm load. 10. R1.2. The data submittal requirements shall stipulate that the load-serving entity count each customer demand within its service territory once and only once, on an aggregated and dispersed basis, in developing its actual and forecast customer demand values. Once again the type of forecast needs to be defined (see comment under Purpose). 11. R1.2 should be revised to recognize that service territories may host multiple LSEs. General Comments 12. Even though the Planning Authorities and Regional Reliability Organizations are supposed to document load forecasts, which in many areas are performed by the Load Serving Entities, there is no requirement for LSEs to actually provide this data to PAs and RROs. 13. In the West, WECC's Resource Adequacy Work Group, identified the disconnect between LSE load forecasting and

Commenter	Comment
	planning and the control area reporting as a major issue in the reporting of quality load and resources data to WECC. Confidentiality issues and other communication issues have contributed to making this an issue of concern therefore the following are action needs: a. Expand the applicability to include Load Serving Entities and Purchasing/Selling entities b. Explicitly state that LSEs are required to provide the documentation for actual and load forecast data for the loads they serve to the PAs and RROs. c. Where Purchasing/ Selling entities are retail access customers who perform load forecasts, specify that these entities also need to provide similar documentation to PAs and RROS. d. Include a provision for dealing with confidentiality of information. 14. Assuming that the intent is to collect information about direct control load management, why is this one type the focus of the requirement? There are various types of demand response programs and tariffs, each with degrees of uncertainty. Knowledge of those programs which are classified as direct control load management is insufficient to know with certainty what quantity of load can be dropped at any specific moment since the underlying loads that are controlled are themselves fluctuating through time. 15. To the extent that load serving entities are required to prepare and submit documentation about DSM, why would this not be extended to all forms of DSM (energy efficiency, onsite generation, etc.) rather than just one small component of DSM activities? 16. What mechanisms exist or must be created to implement the layered set of requirements evidently intended by this standard? Are planning authorities able to compel load serving entities to prepare documentation and submit this documentation in forms that can be passed up to WECC?
Response:	
Dominion John Loftis	(1) In R3 replace regional reliability organization with planning authority. This will make M3 consistent. (2) To be consistent with R1, M1 should refer to both the regional reliability organization and the planning authority. (3) In R1.2 delete the phrase "within its service territory" to accommodate load that is dynamically served from another area. (4) On the whole this standard is poorly written and will be difficult to achieve. In particular the requirement to count each customer once and only once in order to produce a forecast of demand needs to be revisited. Since the subject is producing forecasts, there will be a certain amount of error in the forecast no matter how counting is done. Avoiding double counting is part of minimizing forecast error, but a better standard would be to specify the accuracy expected of the forecast and then to list the components of a good forecast needed to accomplish this. As written, it seems to imply that accuracy may be achieved by simply counting once and only once rather than emphasizing all the aspects of an acceptable forecast. The standard should also refer to the need to coordinate customer loads between load serving entities, particularly where there is shared metering, which would insure that loads are accurately captured.
Response:	
City Water, Light &	In R3 change R1 to Requirement 1 to be consistent with other sections. In Levels of Non-Compliance 2.4 change

Commenter	Comment
Power Karl Kohlrus	"required R1" to "Requirement 1".
Response:	
SERC EC Planning Standards	(1) In R3 replace regional reliability organization with planning authority. This will make M3 consistent. (2) To be consistent with R1, M1 should refer to both the regional reliability organization and the planning authority. (3) In R1.2 delete the phrase (within its service territory) to accommodate load that is dynamically served from another area. The requirement needs to focus on counting of all loads only once, not on who or how it is accounted for.
Response:	
Bonneville Power Administration Lynn Aspaas	1. Requirement R1 - What is the reason for required reporting of "net energy for load data"? Computer simulation models used to validate past events and conduct future system reliability assessments use demand data. The requirement for "net energy for load data" should be omitted. 2. Requirement R1.2 - Replace "load serving entity" with "entities responsible for reporting customer demand." Small load serving entities may have some other entity reporting customer demand for them to other organizations. 3. There are several places that state "... within 30 calendar days of approval." What is approval referring to? If it refers to the Standard or the referenced documentation this would only be a one time requirement, not a Standard that could be assessed on an ongoing basis. It would make more sense if this time frame were tied to when the documentation was requested by some other entity. 4. Requirements R2 and R3 appear redundant. 5. Please clarify the Measures and their relation to the Requirements. Does the RRO develop documentation as required in Requirement R1, make this available to the Planning Authority, then the Planning Authority makes this documentation available to Transmission Planners and LSE's? Or do the RRO and Planning Authority develop seperate documentation as required in Requirement R1, and then make this available to the appropriate entities?
Response:	
Midwest Reliability Organization (G7)	For R3 change Regional Reliability Organization to Planning Authority. For M1 add Planning Authority.
Response:	
PJM Interconnection, L.L.C. Mark Kuras	1. Drafting team should remember that this Standard deals with energy data along with demand data. 2. Compliance elements need to be developed for all the requirements in this standard. Standards should not be revised piecemeal. These added requirements are in the right place in this Standard but the entire Standard needs to be revised not just a small part added. 3. Concern about the references in R1.1. Will this Standard need to be revised anytime that one of these other Standards is revised? For example, the Phase III & IV Standard Drafting Team is proposing that MOD-013-0 be revised and renumbered MOD-013-1. Suggest deleting the present text of R1.1 and replacing it with…The documentation required in R1 shall ensure that consistent data is supplied for all NERC Reliability Standards where

Commenter	Comment
	such data is required to be submitted. 4. In R1.2 change …requirements… to …documentation required in R1… to align better with R1. 5. R3 …regional reliability organization… should probably be …planning authority… 6. In R2 and R3, suggest deleting …for reporting customer demand data, and any changes to that documentation,… and changing …of approval… to …of review or change and approval… 7. M1 should read …The regional reliability organization's documentation and the planning authority's documentation identified in Requirement 1 shall contain all items required. 8. M2 should read …The regional reliability organization shall have records that it provided the documentation required in R1 within 30 calendar days of review or change and approval to each planning authority that works within its region. 9. M3 should read …The planning authority shall have records that it provided the documentation required in R1 within 30 calendar days of review or change and approval to its transmission planners and load serving entities as required in requirement 3. 10. In Section D, 2.3 change …evidence… to …record that…
Response:	
NERC Standards Evaluation Subcommittee Bill Bjorquez – ERCOT	1. The SES recommends the SDT review the draft MOD-016-1 and capitalize all entity names such as: Regional Reliability Organization, Planning Authorities, Transmission Planners, etc. 2. The SES notes that in R1.1, the draft standard describes a list of standards by specific number such as MOD-013-0 that this standard is to supply data to. The SES is concerned that as the standards mentioned in R1.1 are modified, the number will change. For example, in this draft standard, data is to be supplied for MOD-013-0; however, in this Set 2, Phase III/IV proposal, we are considering a new MOD-013-1 for adoption. The SES would recommend the SDT either drop the suffix number, which signifies the version, and note this standard as simply MOD-13. 3. The proposed wording of R2 and R3 as currently proposed is confusing. The SES recommends the SDT revise R2 and R3 to be a single requirement R2 with consistent wording. 4. The proposed wording of M2 and M3 as currently proposed is confusing. The SES recommends the SDT revise M2 and M3 to be a single requirement M2 with consistent wording.
Response:	
American Transmission Co. Peter Burke	The standard has the same capitalization problems as were identified in EPO-005-01. In section R1.1 reference is made to MOD-016-1 which is a standard referencing itself. Is that what was intended?
Response:	
FirstEnergy Raymond Morella	It is suggested that the references to the Reliability Standards in R1.1. be removed and replaced with "…data is supplied for all Applicable Reliability Standards within the TPL and MOD modules." Otherwise, why keep reference to version 0 when version 1 is applicable in some cases.

Commenter	Comment
	Again, proposed effective date should be reviewed as the date reference on the standard does not match the Implementation Plan document. The comments offered regarding Proposed Effect dates should be treated as a general comment for all of the Set 2 standards that the Team to review and adjust as needed.
Response:	
Independent Electricity System Operator Ron Falsetti	5. Requirement R1.1 should be revised to exclude references to specific standards but identify that consistent data is to used for all standards associated with adequacy and transmission assessments. Otherwise the Standard will need to be revised anytime that one of these referenced Standards is revised? For example, the Phase III & IV Standard Drafting Team is proposing that MOD-013-0 be revised and renumbered MOD-013-1. Suggest replacing R1.1 with…The documentation required in R1 shall ensure that consistent data is supplied for all NERC Reliability Standards where such data is required to be submitted or used for resource and transmission adequacy assessments. 6. In R1.2 change …requirements… to …documentation required in R1… to align better with R1. 7. R3 should read ….The planning authority shall distribute… to be consistent to Measure M3. 8. M2 should read …The regional reliability organization shall have records that it provided the documentation required in R1 within 30 calendar days of review or change and approval to each planning authority that works within its region. 9. M3 should read …The planning authority shall have records that it provided the documentation required in R1 within 30 calendar days of review or change and approval to its transmission planners and load serving entities as required in requirement 3. 10. In Section D, 2.3 change …evidence… to …record that…
Response:	
Salt River Project Michael Pfeister	None
Bonneville Power Admin. – PBL Rebecca Berdahl	None
Hydro-Québec TransEnergie Roger Champagne	No comment.
Southern Co Generation (G6)	None
Southern Co Services (G5)	None

Commenter	Comment
U.S Bureau of Reclamation Jay Seitz	None
Comision Electricidad de Federale Jesus Moya Vazquez	None
Ameren John Sullivan	None
U.S. Army Corps of Engineers Karl Bryan	None
British Columbia Transmission Corp. Thomas Fung	None
Tennessee Valley Authority (1) Walter Joly Mark Marcum (5) – TVA Fossil Jerry Nicely (5) – TVA Nuclear Dennis Chastain (1) – Trans. Planning David Marler (1) – Trans. Planning David Thompson (5) – River Syst. Ops. & Env. Bob Millard (1) – T&R Meridith Snyder (1) – T&R	None

Commenter	Comment
Jim Whitehead (1) – Trans. Planning	
NERC Wind Generator Task force Mahendra Patel	The WGTF has no comments.
NPCC CP9, Reliability Standards Working Group (G8)	No comment.
Tennessee Valley Authority (G1)	None
Dynegy Generation Greg Mason	None
We Energies Howard Rulf	None

4. MOD-026 – Some commenters raised a question about the existence of accurate models for excitation system response. These commenters suggested that, 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. Do you think this requirement should be added to MOD-026?

Summary Consideration:

Commenter	Yes	No	Comment
Dynegy Generation Greg Mason		✓	1. This requirement is not needed as there should be existing models which are "close" and can be used. 2. If the requirement is added, it is the applicable ISO and Transmission Operators who need this data. It will be more efficient and economical for the applicable ISO and Transmission Owners to group all excitation systems requiring new models together and arrange for the development of any needed new models.
Response:			
We Energies Howard Rulf		✓	This requirement would be onerous for companies like We Energies because we do not have personnel familiar with or available to develop planning models for excitation systems. This expertise resides with the transmission owner/operator in our case.
Response:			
U.S Bureau of Reclamation Jay Seitz		✓	We believe this is the role of the RRO
Response:			
Mid-Atlantic Area Coordinating Council John Horakh		✓	This could be onerous for small generators with new or different excitation systems. There should be a means for the cost of such software enhancements to be shared among all generators, if absolutely required.
Response:			
BPA (1, 3, 5, 6) Lynn Aspaas BPA – PBL (3, 5, 6) Rebecca Berdahl		✓	All models in the data base should utilize standard library models. If user defined models are used, the data is not convertible between programs. Not all transmission planners use the same computer programs (e.g. PSSE, PSLF). If there are not adequate standard excitation models available, the Generator Owner should be responsible for working with the vendors to develop the required standard models.
Response:			
ISO/RTO Council (G10) Independent	✓ ✓		The reliability need exists to ensure an accurate model is available for reliability studies and the generation owner seems like logical entity to be responsible for the provision of such information.

Commenter	Yes	No	Comment
Electricity System Operator Ron Falsetti			
Response:			
FRCC (G12)	✓		A valid model is necessary for proper simulation. In addition, R1.2 should be re-written to make sure that manufacturer data is only used during the initial stages of development. This data should be replaced by actual field data when it is available.
Response:			
Pepco Holdings, Inc. Affiliates (G9)	✓		A Generator Owner who has obtained a new design excitation system should be able to work with the vendor to devop a model.
Response:			
Dominion John Loftis	✓		Dominion - Electric Transmission endorses the requirement that generator owners develop user written models if no standard model exists in the dynamic software currently being used. Someone has to be responsible for making an accurate model available for reliability studies and the generation owner seems like the right entity to be responsible. Also, even when IEEE has developed (after a time lag) a model for a new excitation system, there is an additional time lag of as much as 2 - 3 years before the dynamic software developers make it available as a standard model. Ideally, the equipment manufacturer (Alstom, GE, etc.), the generator owner, and the software developer (Siemens/PTI, GE, etc.), IEEE (and perhaps IDWG?), should work together to develop an accurate model for any new system.
Response:			
SERC EC Planning Standards (G3)	✓		If this is not added the excitation system may not be adequately represented.
Response:			
Midwest Reliability Organization (G7)	✓		If this requirement is not added it will shift the burden and liability to the Planning Authority and Transmission Planner to translate non-standard models to industry standard models.
Response:			
PJM Interconnection, L.L.C. Mark Kuras	✓		Someone has to be responsible for making an accurate model available for reliability studies and the generation owner seems like the right entity to be responsible.
Response:			
American	✓		The requirement should be added and language should also be included to require the use of the latest

Commenter	Yes	No	Comment
Transmission Co. Peter Burke			IEEE standard, or PSSE, or PSLF/PSDS standard library model to represent the excitation response. It should be the generator owner's responsibility to validate and document the non-standard model so the onus to do this doesn't pass to the Planning Authority and/or Transmission Planner.
Response:			
FirstEnergy Raymond Morella	✓		However, there should be some minimum MVA size used so that it does not become too onerous for small generator owner projects.
Response:			
WECC Reliability Subcommittee (G11) Southern California Edison Mohan Kondragunta	✓ ✓		We agree with the concern raised about the accuracy of models for excitation system response but believe that new models should be developed by having the generator owner work with the program vendors to develop the model. The models should be included in the program model libraries. WECC requries that the models be part of the standard programs and that the data provided by the generator owner be consistent with the models contained in the standard programs. WECC does not accept user-defined models as such models may not have been adequately checked and verified. In addition, user-defined models in one program are difficult, if not impossible to convert to other programs It is important that generator owners and generator vendors work together with program vendors to develop models that are industry accepted and shared. Models must not be proprietary. There must be a way to trasfer/convert data between programs.
Response:			
NERC Wind Generator Task force Mahendra Patel	✓		Does the standard drafting team agree that MOD-026 does not apply to wind generator plants?
Response:			
Tennessee Valley Authority (G1)	✓		None
Comision Electricidad de Federale Jesus Moya Vazquez	✓		None
NPCC CP9, Reliability Standards	✓		

Commenter	Yes	No	Comment
Working Group (G8)			
Ameren John Sullivan	✓		
U.S. Army Corps of Engineers Karl Bryan	✓		
City Water, Light & Power Karl Kohlrus	✓		
ISO New England, Inc. Kathleen Goodman	✓		
NERC Standards Evaluation Subcommittee Bill Bjorquez – ERCOT	✓		
Hydro-Québec TransEnergie Roger Champagne	✓		
Southern Co Generation (G6)	✓		
Southern Co Services (G5)	✓		
Tennessee Valley Authority (G1)	✓		

5. Please identify anything you believe needs to be modified before MOD-026 and MOD-027 are 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

Summary Consideration:

Commenter	Comment
FirstEnergy Raymond Morella	We agree with the drafting team's recommendation to field test the standards prior to balloting.
Response:	
Pepco Holdings, Inc. Affiliates (G9)	MOD-026 -1: See response to Question 4. PHI agrees that MOD-026 and MOD-027 should be field tested before they are sumbmitted for ballo
Response:	
Southern Co Generation (G6)	We support Field Testing of MOD-026-1 and MOD-027. We agree that the Levels of Non-Compliance should be developed as part of the Field Testing process, and will provide our recommendations at that time. For MOD-027, we do not believe there is industry agreement on the specific information to be reported related to generator unit frequency response as spelled out in R1.4. Therefore, the Field Testing process should specifically include refinement of R1.4 as this is worked out.
Response:	
Mid-Atlantic Area Coordinating Council John Horakh	Adding the RRO's requirements into these Standards is logical and a good idea. Moving the design data requirements to MOD-013 is a good idea Field testing for these Standards before proceeding further is the right way to go. There are a lot of concerns and uncertainties that need to be resolved.
Response:	
NERC Wind Generator Task force Mahendra Patel	Does the standard drafting team agree that MOD-026 and MOD-027 do not apply to wind generator plants?
Response:	
ISO New England, Inc. Kathleen Goodman	The above Standards should each be broken into RRO requirements and GO requirements similar to PRC-002-1 & PRC-018-1. In addition the timeline for implementation should be staggered, taking an approach similar to PRC-018-1, to allow the Areas and the Generator Owners sufficient time to assimilate the details contained in what may be a set of newly established RRO procedures and criteria that would otherwise require immediate compliance.

Commenter	Comment
Response:	
Bonneville Power Administration Lynn Aspaas	There are several places in both MOD-026 and MOD-027 that state "... within 30 calendar days of approval." What is approval referring to? If it refers to the Standard or the referenced documentation this would only be a one time requirement, not a Standard that could be assessed on an ongoing basis. It would make more sense if this time frame were tied to when the documentation was requested by some other entity.
Response:	
Midwest Reliability Organization (G7)	For the R1 procedures in MOD-026 add language requiring the use of the latest standard IEEE or PSS/E excitation system and governor models or a validated user-defined model in absence of an appropriate standard model. Not requiring the use of industry standard models will shift the burden and liability to the Planning Authority and Transmission Planner to translate non-industry standard models to industry standard models. Generation Owners should be allowed additional transition time for updating models as required to meet compliance.
Response:	
Hydro-Québec TransEnergie Roger Champagne	We suggest that in MOD-026-1 R1, the procedures includes the necessity for testing of generator excitation system functions and generator unit frequency response. We feel that manufaturer data only is not sufficient.
Response:	
FRCC (G12)	MOD-026-1 R1 should be modified to include the phrase "if applicable" after the words "power system stablizers" in the first sentence. R1.4 should include a requirement to provide information under an appropriate generation level, in addition to R1.4.5 Open Circuit Test. Compliance D1.1.3 Data Retention - RRO requirement - Remove "and previous" from the 1st sentence - There is no need for and no benefit in the RRO retaining "previous" procedures. This requirement could lead to confusion about which procedure is in effect.
Response:	
NERC Standards Evaluation Subcommittee Bill Bjorquez – ERCOT	1. The SES recommends the SDT review the draft MOD-026-1 and MOD-027-1 and capitalize all entity names such as: Regional Reliability Organization, Generation Owner, Transmission Planners, etc. 2. MOD-026-1: This standard appears to apply only to synchronous generators. Because other technologies of generation may become large enough to require appropriate modeling, the SES recommends the SDT add a new requirement (R4) that “Owners of non-synchronous generation that is not exempt from these procedures per R1.1 shall furnish data equivalent to that required in R1.4, as needed to support the data requirements of the Regional Reliability Organization’s analysis models.” 3. For R1.2, the SES believes the proposed standard should state that field testing is the preferred method of data verification. Analysis of blackouts indicates consistently that the accuracy of generator data is not reliable. While commissioning data may be a reliable source of data initially, data can change over time. 4. The SES agrees with the SDT that both MOD-026 and MOD-027 should be field tested prior to final drafting and submission for balloting.

Commenter	Comment
Response:	
Dynegy Generation Greg Mason	MOD-026-1 1. R1.2 Wording similar to that included in R1.2.1 from MOD-013-01 needs to be inserted between R1.2 and R1.3. This suggested wording makes clear the proper use of unit specific data versus generic data for older units installed in 1990 or before. 2.R1.4. To be consistent with R1.2.1 from MOD-013-01, comment #1 above and the impracticality of obtaining some of the data listed under R1.4 for the excitation system of older units, the wording of this requirement needs to be changed to read as follows:" Specific information to be reported related to those generator excitation systems installed in 1990 or before (if available) and for those systems installed after 1990 and their related functions:" 3. R1.4.7 As written, the phrase "…with the voltage regulator in the automatic voltage control mode." implies testing is the only acceptable method of verification(contrary to the provisions of R1.2). Suggest either deleting this phrase or moving it up to R1.2 to follow the word "testing." 4 R3 This section should include a reasonable time for compliance following issuance of the RRO procedures.Since compliance efforts will likely need to occur during a unit outage,suggest compliance deadline of 24 months following issuance of RRO procedures. 4.M3 The Generation Owner is not going to know all the entities that are applicable TP's and PA's. M3 needs to be revised so that the Generation Owner is only required to routinely send its verification of the models associated with its generator excitation system functions to one entity-the RRO.The TP or PA can receive the data from the RRO.This approach will also minimize the risk of creating mutiple sets of the same data.
Response:	
PJM Interconnection, L.L.C. Mark Kuras	MOD-026-1 1. in R1.4.1 add …for example… before text in parentheses. 2. In R1.4.7 drop everything after the comma. Some methods of verification may require the voltage regulator to be in other modes or out of service. 3. In R2 suggest deleting …and any changes to those procedures… and changing …of approval… to …of review or change and approval… 4. In M2 and M3 change …evidence… to …records… 5. In M3 change …provide verification… to …provide records of verification…
Response:	
ISO/RTO Council (G10) Independent Electricity System Operator	MOD-026-1 1. R1.2 -The IRC suggests an appropriate definition or guidelines be added to explain what constitutes "Acceptable methods". 2. R1.3 -The same comment applies regarding "periodicity" . It is the IRC view periodicity should be standardized and not Regional specific. Regions cuold review more frequently if they desired to do so. 3. R1.4 - is this the complete list or is it an example of the type of items to be reported?

Commenter	Comment
Ron Falsetti	4. R1.4.1 add …"for example"… before text in parentheses. 5. R1.4.7 drop everything after the second comma. Some methods of verification may require the voltage regulator to be in other modes or out of service. 6. R2 suggest deleting …"and any changes to those procedures"… and changing …"of approval"… to …"of review or change and approval"… 7. In M2 and M3 change …"evidence"… to …"records"… In M3 change …"provide verification"… to …"provide records of verification"…
Response:	
U.S Bureau of Reclamation Jay Seitz	MOD-026 1. This standard should also be applicable to the transmission planner whose role should include performing a quality check on modeling data before it is incorporated into system-wide models. 2. The RRO procedures should include a reasonable implementation period. This will also allow generator owners with many units to spread out the periodicity of re-validating models. 3. R1.4.5 requires open circuit test response data. We believe this requirement should be expanded to allow the RRO to include alternate methods of determining machine response such as monitors that capture and record the generator response to real system events. 4. Each measure should state which requirement it assesses. 5. M3 - We believe the generator owner should provide model verification data only to the transmission planner with the understanding that the modeling data is incorporated into the RRO system-wide model. All eligible entities may then make use of the system-wide models provided by the RRO. Providing the data to more entities increases the risk of incorporating wrong data and confusing the chain of responsibility.
Response:	
Dominion John Loftis	(1) In M3 of MOD-026 delete "to the regional reliability organization, and appropriate transmission planner and planning authority" to make it consistent with R3. A similar change needs to be made to M3 of MOD-027 for the same reason. (2) On a general note, why is each regional reliability organization being delegated responsibility for developing regional methods to verify models and data vs. the development of global requirements that would be applicable to all RROs on a consistent basis?
Response:	
Ameren John Sullivan	MOD-026-1 : (1) Requirement R1.2 should place greater weight on testing and field verification of equipment as installed, rather than use of typical manufacturer's data for the generator excitation systems. Typical manufacturer data may be adequate for early phases of study work, but would need to be updated with model data based on the actual equipment to be installed. (2) R1.3 should specify a maximum time period for verification (five years), rather than leave the periodicity completely open.
Response:	

Commenter	Comment
SERC EC Planning Standards (G3)	In M3 of MOD-026 delete (to the regional reliability organization, and appropriate transmission planner and planning authority) to make it consistent with R3. A similar change needs to be made to M3 of MOD-027 for the same reason.
Response:	
We Energies Howard Rulf	MOD-026-1 Verification of Models & Data for Generator Excitation System Functions C. M3: The generator owner is required to show verification to the RRO and "appropriate transmission planner and planning authority". This requirement should be revised. It should be sufficient to report this information to the RRO, which should be responsible to transfer necessary data to the transmission planner or other entities.
Response:	
U.S. Army Corps of Engineers Karl Bryan	1. MOD-026-1, the transmission service provider should have a QC role in the verification of the model data provided. The TSP needs to use the modelling data in their planning studies and it makes sense for them to be the primary reviewer of the generator owner/operator's model data prior to the model data being forwarded to the RRO. The RRO should perform a QA role on reviewing the data by performing a spot check. The other transmission planning groups within the RRO would also play into the QA process. The main player in the review and validation of the useability of the generator owner/operator's model data should be the transmission service provider for that facility. 2. The RRO should provide an acceptable list of models and it should be the generator owner/operator responsibility to match their equipment to the acceptable models. The RRO should not have to accept models that their power simulation programs do not recognize or use. 3. The standard should recognize that after the initial testing of the generator has been performed, the use of continuous online monitoring equipment can be used to meet the requirement of periodic reverification of the machine parameters. The cost of the online monitors is far less than the cost of retesting the generators. An added benefit of utilizing continuous online monitors for capturing the generators response to a system disturbance is the information from these online monitors can also provide more information for analyzing the system disturbance. More eyes and ears on the power system can help improve the system models.
Response:	
WECC Reliability Subcommittee (G11) Southern California Edison Mohan Kondragunta	MOD-026-1 The R1.4 subrequirements are too proscriptive and request information that is not applicable to all generators. Suggest deleting R1.4.
Response:	
Tennessee Valley Authority (G1)	MOD-027-1: Nuclear Plants should be exempt from this Std. due to their inability to exceed 100% Reactor Power per NRC Commitments.
Response:	

Commenter	Comment
American Transmission Co. Peter Burke	The standard has the same capitalization problems as were identified in EPO-005-01. This standard doesn't address how generator data is shared between RROs and if this isn't addressed in another standard then a provision for cross region data sharing should be added.
Response:	
Midwest Reliability Organization (G7)	For the R1 procedures in MOD-027 add language requiring the use of the latest standard IEEE or PSS/E excitation system and governor models or a validated user-defined model in absence of an appropriate standard model. Not requiring the use of industry standard models will shift the burden and liability to the Planning Authority and Transmission Planner to translate non-industry standard models to industry standard models. Generation Owners should be allowed additional transition time for updating models as required to meet compliance.
Response:	
WECC Reliability Subcommittee (G11) Southern California Edison Mohan Kondragunta	MOD-027-1 R1 should set the minimum requirement and the RRO can set something more stringent. For example "up to 30 seconds" should be changed to "minimum of 30 seconds" as a RRO may require more than 30 seconds for post-transient simulations. The R1.4 subrequirements are too proscriptive and request information that is not applicable to all generators. Suggest deleting R1.4
Response:	
U.S Bureau of Reclamation Jay Seitz	MOD-027 R1 – 30 seconds may not be long enough to capture the response of slower units; recommend it be changed to 60 seconds.
Response:	
U.S. Army Corps of Engineers Karl Bryan	MOD-027-1, I agree with the requirement for verifying generating unit frequency response. I do think the time frame should be extended to 1 minute, that way you will capture the quick response and decay of response that a thermal machine exhibits in the 0-40 second range and you will capture the slow response but sustained response that a hydro machine exhibits in the 25 second and beyond range. I think the goal is to better capture what generators are capable of performing and sustaining and the present 0-30 second range is too short a time frame.
Response:	
Dynegy Generation Greg Mason	MOD-027-1 1. R1.2 Wording similar to that included in R1.2.1 from MOD-013-01 needs to be inserted between R1.2 and R1.3. This suggested wording makes clear the proper use of unit specific data versus generic data for older units installed in 1990 or before. 2.R3 This section should include a reasonable time for compliance following issuance of the RRO procedures.Since compliance efforts will likely need to occur during a unit outage,suggest compliance deadline of 24 months following issuance of RRO procedures.

Commenter	Comment
	3. M3 The Generation Owner is not going to know all the entities that are applicable TP's and PA's. M3 needs to be revised so that the Generation Owner is only required to routinely send its generator frequency response data to one entity-the RRO.The TP or PA can receive the data from the RRO.This approach will also minimize the risk of creating mutiple sets of the same data.
Response:	
PJM Interconnection, L.L.C. Mark Kuras	MOD-027-1 In R2 suggest deleting …and any changes to those procedures… and changing …of approval… to …
Response:	
NERC Standards Evaluation Subcommittee Bill Bjorquez – ERCOT	MOD-027-1: This standard appears to apply only to synchronous generators. Because other technologies of generation may become large enough to require appropriate modeling, the SES recommends the SDT add a new requirement (R4) that "Owners of non-synchronous generation that is not exempt from these procedures per R1.1 shall furnish data equivalent to that required in R1.4, as needed to support the data requirements of the Regional Reliability Organization's analysis models." For R1.2, the SES believes the proposed standard should state that field testing is the preferred method of data verification. Analysis of blackouts indicates consistently that the accuracy of generator data is not reliable. While commissioning data may be a reliable source of data initially, data can change over time.
Response:	
Hydro-Québec TransEnergie Roger Champagne	4. We suggest that in MOD-027-1 R1, the procedures includes the necessity for testing of generator excitation system functions and generator unit frequency response. We feel that manufaturer data only is not sufficient. 5. In MOD-027-1, in the title and purpose, the words "and status" are crossed although we still find them in R1 and M1, correction to make it consistent is needed. 6. In MOD-027-1R1, to make it consistent with M1, the procedure should address "verification and reporting". 7. In MOD-027-1R1.4, provision should be made to include model of turbine / prime mover.
Response:	
SERC EC Planning Standards (G3)	*In M3 of MOD-026 delete (to the regional reliability organization, and appropriate transmission planner and planning authority) to make it consistent with R3.* A similar change needs to be made to M3 of MOD-027 for the same reason.
Response:	
ISO/RTO Council (G10) Independent Electricity System Operator	MOD-027-1 R2 suggest deleting …and any changes to those procedures… and changing …of approval… to …of review or change and approval… M2 and M3 change …evidence… to …records… Where it has been changed from the previous draft (ie under R3 and M1), prefer to see Requirement R1 or R2 as this is

Commenter	Comment
Ron Falsetti	what they are actually labelled as.
Response:	
We Energies Howard Rulf	MOD-027-1 Verification of Generator Unit Frequency Response C. M3: Similar to above comment. The generator owner is required to show evidence it provided frequency response data to the RRO and "transmission planner and transmission operator". This requirement should be revised. It should be sufficient to report this information to the RRO, which should be responsible to transfer necessary data to the transmission entities.
Response:	
FRCC (G12)	MOD-27-1 Compliance D1.1.3 Data Retention - RRO requirement - Remove "and previous" from the 1st sentence - There is no need for and no benefit in the RRO retaining "previous" procedures. This requirement could lead to confusion about which procedure is in effect.
Response:	
City Water, Light & Power Karl Kohlrus	None
Comision Electricidad de Federale Jesus Moya Vazquez	None
Salt River Project Michael Pfeister	None
Bonneville Power Admin. – PBL Rebecca Berdahl	None
NPCC CP9, Reliability Standards Working Group (G8)	No comment.
Southern Co Services (G5)	None
British Columbia Transmission Corp. Thomas Fung	None

6. Please identify anything you believe needs to be modified before VAR-001 through VAR-003 are 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

Summary Consideration:

Commenter	Comment
U.S. Army Corps of Engineers Karl Bryan	The references to "synchronous generators" should be removed from this standard. The standard should apply to all generators connected to the bulk electric system. Each requirement should also have a measure associated with it, otherwise how will you be able to determine if the requirement is being met. VAR-001-1, I don't see any requirement for verifying that the reactive resources are truly available. Performing a survey is not the same as actually testing to see if the reported reactive resource can operate at the maximum and minimum levels of the device. Recommend an annual testing of reactive resources be implemented so that the reactive capability on the system is truly available.
Response:	
U.S Bureau of Reclamation Jay Seitz	VAR-001 Definitions 1. No new definitions are proposed by this standard; however, the draft standard refers to “voltage schedule” and “reactive power schedule” in several of the requirements. We believe there is widespread difference of opinion or confusion throughout the industry as to what these terms mean. We believe that if “voltage schedule” and “reactive power schedule” are used in the standard, then precise definitions are needed. This further leads to the question of the purpose of the standard including both “voltage schedule” and “reactive power schedule”. If reactive power schedule equates to machines operating in VAR control those machines will not be responding automatically to voltage fluctuations or disruptions on the system. This seems counterproductive to our reliability goals. We make a general recommendation that the standard be targeted to voltage control and voltage schedules and not address reactive power schedules. In addition, voltage schedules should include a tolerance band. Requirements 2. There are 13 requirements listed for this standard, some with sub-requirements. Only 4 measures are defined; there should be a clear measurement for each requirement. Without a specific measurement paired to each requirement (or sub-requirement) we do not believe compliance can be determined. 3. Requirement R2 concerns exemptions to requirements R5 and R7. We believe the standard would be more readable if it were listed after R5 and R7 or incorporated into each of those requirements. 4. Requirement R3 may be the most important in the entire standard yet there is no discernable measure to detect and

Commenter	Comment
	gauge compliance. The phrase “acquire sufficient reactive resources” is very important for maintaining reliability of the bulk power system; but it has presupposed that there has been a determination as to what reactive margin is required. Of course the devil is in the details and how a Transmission Operator demonstrates and documents that they have accomplished this needs to be somehow defined. This may point to the need for the methods and metrics to be fleshed out at a regional level. 5. Requirement R5 obligates the Transmission Operator to specify a schedule for each synchronous generator. In addition the requirement has targeted the individual unit level. We recommend the voltage schedule be applicable at the facility or plant level. It is not practical or desirable especially for facilities that include multiple units such as hydro plants or wind farms, to schedule voltage and watts (not vars) at the individual generator level. The voltage schedule should also include a tolerance band. 6. We believe this voltage requirement should apply to all generation, not just synchronous. The way this requirement is drafted it appears to exempt wind farms and other non-synchronous generators from participating in maintaining system voltages. 7. Requirement R7 obligates Transmission Operators to know the status of all reactive power sources including AVRs and PSSs. This provision needs to clarify that it means generator is available and if dispatched will operate in voltage control mode and with the PSS active. As written the standard may be interpreted as requiring real time data for each generator’s AVR and PSS status. For the Western Interconnection the Western Electricity Coordinating Council (WECC) requires generators to operating in voltage control mode and for those units with PSS to operate with the PSS active. Generation owners report compliance with this policy to WECC on a quarterly basis. 8. Requirements R8 and R9 appear to overlap significantly. We recommend the drafting team consider consolidating them. We also recommend the language be restricted to maintaining voltage levels rather than reactive flow.
Response:	
NERC Standards Evaluation Subcommittee Bill Bjorquez – ERCOT	The SES recommends the SDT review the drafts VAR-001-1, VAR-002-1, and VAR-003-1 and capitalize all entity names such as: Transmission Operators, Generation Owner, Generation Operators, Planning Authorities, Transmission Planners, etc. 1. ˜ VAR-001-1: The SES believes the SDT should include a Measure that will require the Transmission Operator to provide evidence that it made its formal policies and procedures documentation regarding voltage and reactive control available to the Regional Reliability Organization. 2. Overall, the SES is concerned that this proposed standard has requirments beyond the control of the responsible entity noted. For example, in R3, the Transmission Operator only has the reactive resources that exist in the area--how does the TO "acquire sufficient reactive resources" if existing resources are not adequate? The SES questions if R3 is not more appropriately addressed to the Transmission Planner? Or in the alternative, should the word "aquire" in R3 be replaced with the word "operate"? Similarly, R6 and R10.1 presumes that sufficient reactive resources are available. 3. The SES also questions should the Regional Reliability Organization be included in the Applicability section? 4. M2 and M4: The SES questions should these measures have corresponding levels of Non-Compliance proposed? 5. M4: Requirement 11 referenced in M4 should be Requirement 12.

Commenter	Comment
Response:	
Bonneville Power Admin. – PBL Rebecca Berdahl	VAR-001 The references that note "synchronous generators" should be removed so that it is clear that these stardards are applicable to all generators. Requirement R6: What measure is applied to the purchasing-selling entity?
Response:	
NERC Wind Generator Task force Mahendra Patel	VAR-001-1 R4 should also include a list of exempt wind generator plants (not individual wind generators). R5 should incorporate wind generator plants (not individual wind generators) that are not exempt from the requirement.
Response:	
Hydro-Québec TransEnergie Roger Champagne	In VAR-001-1 R5, voltage schedule should be the normal setting with reactive schedule being the exception.
Response:	
Bonneville Power Administration Lynn Aspaas	VAR-001 – 1. All generators, synchronous and non-synchronous, should make every effort to provide system voltage support. The references that note "synchronous generators" should be removed so that it is clear that these stardards are applicable to all generators connected to the 2. Requirement R6, Should there be some measure that applies to the purchasing-selling entity that ensures this requirement was carried out? 3. Requirement R7, There should be a measure for this requirement that specifies how this information is to be documented and how often. 4. Measure M4 seems to refer to Requirement 12 not Requirement R11. 5. There are many requirements in this Standard which do not have associated measures. Perhaps this Standard is not ready for balloting.
Response:	
Ameren John Sullivan	VAR-001-1 : (1) In R1, the first sentence mentions the development of policies and procedures, while in Reliability Standard VAR-003-1, Requirement R1, the first sentence mentions the establishment of a method and criteria for assessing reactive power requirements. Do the terms 'policies and procedures' and 'method and criteria' have the same meaning in these standards or is something different meant for each set of these terms? (2) Will this standard apply to wind generation? If not, will a separate standard be developed for wind generation? (3) Requirement R3 covers normal and contingency conditions, while R10 mentions only first contingency conditions. Is

Commenter	Comment
	there a reason for this difference? Also, it is not clear what is meant in the second sentence in R3 by the phrase 'transmission operator's share of the reactive requirements of interconnecting transmission circuits'. What would be the reactive requirements of transmission circuits? (4) Will R6 also apply to wind generation absorbing reactive power at the point of interconnection? (5) In R10.1, does 'disperse and locate' mean the same as 'dispatch'? If so, changing the wording to 'dispatch' would make the meaning clearer. (6) Requirement R12, the corresponding measurement M4, and corresponding Compliance section 2.1.2, which cover generator step-up transformer tap changes and related documentation, would be better located within Reliability Standard VAR-003-1. Reliability Standard VAR-001-1 deals with voltage and reactive control in real time, while Reliability Standard VAR-003-1 deals with reactive power resource assessment in the planning time frame.
Response:	
Dominion John Loftis	On VAR-001 not all of the requirements are captured in the measurements. In VAR-001, R10 remove "first" so as not to limit this requirement to first contingency conditions. As written with or without removing "first", R10 provides no additional information not already required in R3. This requirement would read better if the current R10.1 was relabeled R10 and the current R10's repeat of R3's requirement be removed.
Response:	
PJM Interconnection, L.L.C. Mark Kuras	VAR-001-1, R4 should be a subbullet of R2. In R12, second line, first …the… should be lower case.
Response:	
SERC EC Planning Standards (G3)	On VAR-001 not all of the requirements are captured in the measurements. In VAR-001, R10 remove "first" so as not to limit this requirement to first contingency conditions. As written with or without removing "first", R10 provides no additional information not already required in R3. This requirement would read better if the current R10.1 was relabeled R10 and the current R10's repeat of R3's requirement be removed.
Response:	
ISO/RTO Council (G10) Independent Electricity System Operator Ron Falsetti	VAR-001-1 R3 Suggest changing the phrase…"to protect the voltage"…. to "maintain the voltage" R4 should be a subbullet of R2.. R5, R7.1 & M1 A clarification is requested to define what constitutes a voltage or reactive power schedule in the context of a market based system that operates the system to pre-defined bus voltage operating limits and requiring all generators to operate their AVRs in auto voltage control maintaining its terminal voltage within predefined voltage performance criterion and/or follow any specific VAR dispatch instruction issued by the TOP. R11 Remove reference to 30 minutes, TOP-007 - IORL/SOS reporting requirements includes the timeline for violations

Commenter	Comment
	reporting and should be referenced in this standard rahter than included again here. R12 Line above appears to be part of R12, if so then second line, first …"the"… should be lower case. It is the IRC's view the standard needs to be developed to incorporate measures/compliance elements for all requirements within the standard and NERC should avoid evolving / developing standards piecemeal.
Response:	
Dynegy Generation Greg Mason	VAR-001-1 1.R5 This requirement needs to be modified to state that a voltage schedule must be a range of voltage(not a specific point voltage) and that voltage schedule should take into account voltage measuring accuracy and the dynamics of system voltage.The voltage schedule must be a range of voltage(and not a specific point voltage) in order to comply with the R3 provisions of VAR-002-1. 2.R11 There is one sentence left over from the former R17 that needs to be moved or deleted. 3.R12 As redrafted,this section deletes the prior requirement for a transmission operator and generation owner to "mutually agree" on tap changes for generator step up transformers at a plant and now allows a transmission operator to require the generation owner to make changes to these tap settings in a specified timeframe. These tap settings need to balance system requirements such as reactive output and plant requirements such as generator and auxiliary voltages that impact reliable plant operation.Also, changes to these tap settings could result in additional plant expenditures and they would need to be made during a plant outage(not at a time specified by the transmission operator). This new wording that allows a transmission operator to dictate these tap settings is bad for overall system reliability,discourages cooperation between the entities and needs to be removed. The prior wording that required "mutual agreement" between the transmission operator and generation owner on these tap setting changes should be reinstated. 4.M1 This measure references a "criteria specified in Requirement R5". As drafted,R5 does not have any "criteria".However, R5 does need to be revised to include criteria such as in my comment #1 above on R5.
Response:	
Midwest Reliability Organization (G7)	VAR-001-1: For M4 and D2.1.2 change R11 to R12.
Response:	
FRCC (G12)	VAR-001-1 Add a new measure - M5. The Purchasing-Selling Entities shall have evidence to show that they arranged for reactive resources to satisfy their reactive requirements as idenfied by their transmission service provider.
Response:	
WECC Reliability Subcommittee (G11) Southern California Edison	VAR-001-1: 1. R4 and R5 should be applicable to all generators. Therefore, delete the word "synchronous" from both requirements. 2. R8: How does a transmission operator demonstrate compliance with this requirment? 3. R11: Delete "and complete the required IROL or SOL violation reporting.' This is redundant with the requirements of TOP-007. Is is not appropriate for one standard to require compliance with another approved standard.

Commenter	Comment
Mohan Kondragunta	4. M2: Which requirement does this measure apply to?
Response:	

American Transmission Co. Peter Burke	VAR-002 The standard has the same capitalization problems as were identified in EPO-005-01.
Response:	
NERC Wind Generator Task force Mahendra Patel	VAR-002-1 The standard drafting team should consider incoporating requirements that parallel R1 and R2 for wind generator plants (not individual wind generators) that have dynamic reactive capabilities.
Response:	
FRCC (G12)	VAR-002-1 R1 & R2 should address non-synchronous generators.
Response:	
Bonneville Power Administration Lynn Aspaas	VAR-002, - All generators, synchronous and non-synchronous, should make every effort to provide system voltage support. The references that note "synchronous generators" should be removed so that it is clear that these stardards are applicable to all generators connected to the
Response:	
Dynegy Generation Greg Mason	VAR-002-1 1.R1 and M1 To be consistent with R3 and the practicalities of system operation, the last phrase "…unless otherwise approved by the transmission operator" needs to be deleted from R1 and M1 needs to be eliminated..R3.1 requires the generation operator to notify the transmission operator of any change in the status of the voltage regulator. Obtaining "approval" of the transmission opearator before the voltage regulator is taken off automatic voltage control mode may not always be possible given equipment failures and priorities of real time operations. 2. R3 Given the operational interface between transmission operators and Reliability Coordinators, suggest changing the entity receiving the notification from transmission operator to Reliability Coordinator.This change will allow the generation operator to notify one entity(the Reliability Coordinator) and the Reliability Coordinator can then coordinate this information with the transmission operator. 3.R3.3,M2 and D2 These requirements only make pratical sense if the voltage schedule is a voltage range and not a specific point voltage.See my comment #1 on R5 of VAR-001-1. 4.R5 Either change this sction to coordinate with recommended change to R12 of VAR-001-1(see my comment #3 on VAR-001-1) or leave alone. 5.M5 The sentence needs to be modified as follows to fully comply with R5:" The generation owner shall have evidence that its step-up transformer taps were modified per the transmission operator's documentation or the reason why these changes could not be made as required in Requirement 5." 6.D2.1.1,D2.2.1,D2.3.1 and D2.4.1 The terms used in these non-compliance levels need to be better defined.Do any

	violations within the 30 minute notification period not "count"? Is the term "accumulated time of xxx unit hours" referring to consecutive hours for a unit outside the voltage range? When does a new period for judging compliance begin---immediately after the period in which the voltage schedule is met again?Is the voltage being measured the integrated transmission voltage over an hour rather than instantaneous values? For a multiple unit plant,isn't compliance measured on a plant rather than unit basis? 7.D2.1.1,D2.2.1,D2.3.1 and D2.4.1 With regard to not holding voltage schedules, why should a Generation Owner be considered non-compliant in the instance where a unit/plant was generating or absorbing maximum MVARs but still could not maintain the voltage schedule due to system conditions? These non compliance levels need to take into account this type of possible occurrence. 8.D2.1.2.D2.2.2,D2.3.2 and D2.4.2 These levels of non compliance need to be eliminated to coordinate with my above comment #1 on VAR-002-1 and since D2.1.3,etc. covers inadequate notification occurences.
Response:	
ISO/RTO Council (G10)	VAR-002-1 1. R3 This requirement should be reworded to states that the generator shall notify its associated transmission operator "asap" to allow the transmission operator to re-prepare the system for the next contingency within 30 minutes. 2. M4 should be Requirement 12 instead of Requirement R11. 3. VAR-002-1 in R5 last line remove the first …"or"… 4. In all Measurements and in Compliance section 1.3, change …"evidence"… to …"records"… 5. VAR-003-1 in R2.1 change …"known"… to …"common"… 6. The first sentence in R2.2 is very difficult to determine compliance for. The first sentence of R2.2 should be deleted unless criteria is supplied. 7. In all Measurements, change …"evidence"… to …"records"… 8. No mention of Measurement 3 in Levels of Non-Compliance. 9. In Section D 2.2 change …"known"… to …"common"…
Response:	
U.S Bureau of Reclamation Jay Seitz	VAR-002 We believe the purpose of this standard would more clear if it dealt only with voltage control and voltage levels. We think including reactive power resources and reactive flow only complicates the objective. Requirement R2 and corresponding measure M2 require that the generator follow the voltage schedule and be able to prove it. The compliance process requires that generators retain this evidence for a rolling 12 months. We think some more detail needs to be provided at to how this is to be accomplished. We believe this concept has been worked out within WECC; generator owners are required to operate in the voltage control mode and report compliance on a periodic (quarterly) basis. This process works. However; if the drafters are contemplating some sort of recording device to continually monitor voltage settings and AVR and PSS status and storing that data for 12 months, we think that approach is not needed or cost effective.
Response:	
PJM	VAR-002-1 in R5 last line remove the first …or… In all Measurements and in Compliance section 1.3, change

Interconnection, L.L.C. Mark Kuras	…evidence… to …records…
Response:	
Dominion John Loftis	1. The requirements of VAR-002 are confusing. The requirement seems to be for a cumulative total over a rolling 12-month period, but the compliance reset timeframe is shown as one calendar year. It would seem that the reset period should be shown as one month. Also, it is assumed that compliance is cumulative, that is, that incidents of noncompliance within the rolling 12 months are additive. These requirements should be reworded to be clearer. 2. Since deviation from schedules will constitute the basis for noncompliance, and that the allowable magnitude of this deviation will be established by the transmission operator alone, it seems that VAR-001 should spell this out more specifically in the duties of the TO. 3. There seems to be nothing written in the levels of Non-Compliance about the Generator Operator being out of compliance for not maintaining records, so if the generator operator does not keep any evidence of being out of compliance is he meeting the standard or is this only implied?
Response:	
U.S. Army Corps of Engineers Karl Bryan	1. VAR-002-1, recognition of the use of Automatic Generation Control links for dynamically communicating real-time voltage schedules should be mentioned in the Measures section. Some of our generators receive voltage schedule information from the transmission service provider as well as information on voltage schedule compliance. This information is available from the transmission service provider and it doesn't make sense for the generation owner/operator to archive this information when it is also archived by the TSP. 2. An additional requirement, "R6. The generator owner will annually test the static reactive capabilities of each of their generators and shall submit the information to the transmission operator." A good example of the type of static reactive testing would be the WECC Synchronous Machine Reactive Limits Verification that was required after the 1996 Aug West Coast system disturbance. Please note that the annual testing should be performed on all generators connected to the bulk electric system and not just synchronous machines. The testing is easily performed by the generator operators and it does give the generator operators experience in operating the generators to the extremes of the reactive limits of the machine capability curve. A few of the benefits of performing this testing is the operators learn more about the generators capabilities, find limiters and protective devices that would limit the machine from operating at max/min VARS, discover equipment deficiencies and deal with them prior to having these deficiencies add to the problems of a major system disturbance. 3. Along with the additional requirement is the following recommended measure, "M6. The generator owner shall have evidence that it has performed the annual static reactive capability testing and has submitted the information to its transmission operator."
Response:	
Bonneville Power Administration	VAR-002 Requirement R5.1 states "... the generator operator shall notify the transmission operator and shall provide the

Lynn Aspaas	associated reason." This statement does not allow for partially meeting the transmission operators specifications. There may be cases where transformer taps can be changed to provide some benefit, but cannot be changed in the full range to meet the specification. Rather than the requirement to give an associated reason not to change transformer taps, there should be flexibility to be able to change some taps in conjunction with other options.
Response:	
Midwest Reliability Organization (G7)	VAR-002-1: For R2.1 please clarify what is meant by alternative method, what alternative methods are acceptable and that manual control is acceptable. For R4 in addition to the Transmission Operator and Transmission Planner, add Planning Authority and Reliability Coordinator as being able to request data from the Generator Owner. For R5.1 change "associated reason" to "technical justification" to match the wording in VAR-001-1 R12 or vice versa.
Response:	
WECC Reliability Subcommittee (G11) Southern California Edison Mohan Kondragunta	VAR-002-1 R2 and R3: Is it required that generator owners store the data requested in R2 and R3? How should they provide evidence that they have complied with these requirements. R2: This requirement should be applicable to both synchronous and induction generators. WECC requires that Induction generators provide reactive support (SVC)
Response:	
NERC Standards Evaluation Subcommittee Bill Bjorquez – ERCOT	VAR-002-1: The SES recommends the SDT change the notification requirement in R3 (M3 and subsequent Levels of Non-Compliance) for Generating Operators to notify its Transmission Operator regarding changes in the status of the generating unit's reactive capabilities to allow each Region to set its own notification (time) requirement, but in no instances should the time limit exceed 30 minutes.
Response:	
Bonneville Power Admin. – PBL Rebecca Berdahl	VAR-002 R2 and R3: Clarify whether data storage becomes necessary for compliance.
Response:	
Independent Electricity System Operator Ron Falsetti	VAR-002-1 R3 This requirement should be reworded to states that the generator shall notify its associated transmission operator "asap" to allow the transmission operator to reprepare the system for the next contingency within 30 minutes. M4 should be Requirement 12 instead of Requirement R11.
Response:	
Southern Co Generation (G6)	We have a number of comments on VAR-002-1: 1. R2.1: We have concerns about the wording of R2.1 and how this could be interpreted (implies strict adherence to the

	voltage/reactive schedule even if operating in manual regulator). Our experience supports a joint effort between the Generator Operator and the Transmission Operator to define reasonable operating limits when operating in this mode. For example, operation in the under excited region of the generator capability curve is not desired since the URAL is not active when in manual regulator mode and a single contingency event (example: loss of the strongest source) could result in exceeding the steady state stability limit and loss of synchronism. Thus, if strict adherence to the voltage schedule by the affected generator requires operation in the under excited region, this could set up a condition that is detrimental to the generator and system stability/reliability. 2. M2: Measurement of compliance with R2 is actually covered (and more easily measured) by compliance with R3 as addressed in M3. Thus, M2 is not needed and can be deleted. 3. M3: We recommend revising the end of the sentence to say: changes identified in Requirement 3. (i.e., instead of Requirements R3.1 through R3.3) This wording encompasses the main requirement plus all three sub-requirements. Levels of Non-Compliance: We understand the need to have defined levels of non-compliance. However, it is anticipated that the implementation of the reporting requirements and assessments of compliance for this standard will be difficult to accomplish in practice. 4. We recommend a Field Test Period be established to develop more practical Levels of Non-Compliance and to allow time for Generator Owners and Operators to develop appropriate training and reporting procedures to help ensure operation that complies with the requirements. Southern Company Generation supports the standard drafting team's decision to provide the Generator Operator the chance to provide documentation in support of their reasons for not responding in the 30 minute window. For instance, during emergencies, it is possible that the Generator Operator will not have the opportunity to respond within the 30 minutes due to their efforts with stabilizing the generator and, therefore, would be agreeable to providing the documentation.
Response:	
Southern Co Services (G5)	Under VAR-002, we feel that the provisions under R.3 seem very reasonable.
Response:	

Bonneville Power Administration Lynn Aspaas	VAR-003, - All generators, synchronous and non-synchronous, should make every effort to provide system voltage support. The references that note "synchronous generators" should be removed so that it is clear that these stardards are applicable to all generators connected to the
Response:	
Bonneville Power Admin. – PBL Rebecca Berdahl	VAR-003 The terms "static and dynamic" should be removed from the Standard or further defined. In general, reactive power requirements and voltage issues are specific to both the location and cause of a voltage stability problem (e.g. local load reactive demand, transmission line reactive losses) and need to be assessed on a case by case basis, i.e., area specfic. Consider developing a measurement that would support/demonstrate the ability of a reactive power source(s) provide the necessary reactive support to an area based on the location of the source relative to the voltage problem.
Response:	
Bonneville Power Administration Lynn Aspaas	VAR-003 1. We believe the contents of this Standard should be included in the TPL series of Standards. Having all Standards associated with assessing transmission system performance consolidated in one place saves time and helps ensure that transmission planners include all the necessary studies required to show compliance. The terms "static and dynamic" should be removed from the Standard. In general, reactive power requirements and voltage issues are specific to both the location and cause of a voltage stability problem (e.g. local load reactive demand, transmission line reactive losses) and need to be assessed on a case by case basis. The mix of static and dynamic reactive power requirements is very different for different areas. Also, having a specific requirement for dynamic reactive power for an area does not ensure the reactive power source will provide the reactive support necessary based on the location of the source relative to the voltage problem. If the terms "static and dynamic" are to be included in this Standard there needs to be definitions for static and dynamic reactive power sources. For example, dynamic reactive power sources could include 1) shunt capacitors or reactors that switch automatically on voltage control or as part of an SPS, 2) static VAR compensator, 3) synchronous condensor, or 4) synchronous generator. A static reactive power source could be shunt capacitors or reactors that are switched manually or with some time delay.
Response:	
Pepco Holdings, Inc. Affiliates (G9)	VAR-003 appears to duplicate the requirements of TPL-001-0.
Response:	
NERC Standards Evaluation Subcommittee Bill Bjorquez –	VAR-003-1: The assessment of reactive power is inherent in the assessment required by the TPL series of standards--therefore the SES questions the value of this standard as proposed. A standard defining reactive margin may be more appropriate. However, should the SDT belive this standard as proposed is appropriate, the SES offers the following additional comments:

ERCOT	R1: This requirement should establish the method and criteria for assessing adequate static and dynamic reactive power. The SES believes that leaving this to the discretion of the Transmission Planner and Planning Authority will result in inconsistent requirements. The SES asks the SDT if they are aware of any existing methods and criteria currently used in the industry. R2: This requirement is duplicative of the TPL standards. R2.1: As drafted, this requirement is very general and vague in nature. The SES recommends the SDT be more specific with respect to the objective of the requirement. For example, is the SDT looking for sensitivity studies to changing power factor, etc.?
Response:	
Ameren John Sullivan	VAR-003-1 : Requirement R1 states that the transmission planner and planning authority shall each establish a method and criteria for assessing reactive power requirements. Why would both entities need to do this?
Response:	
PJM Interconnection, L.L.C. Mark Kuras	VAR-003-1 1. in R2.1 change …known… to …common… 2. The first sentence in R2.2 is very difficult to determine compliance for. The first sentence of R2.2 should be deleted unless criteria is supplied. 3. In all Measurements, change …evidence… to …records… 4. No mention of Measurement 3 in Levels of Non-Compliance. 5. In Section D 2.2 change …known… to …common…
Response:	
ISO New England, Inc. Kathleen Goodman NPCC CP9, Reliability Standards Working Group (G8)	In VAR-003 Section R 2.2, the assessment should be optionally conducted "jointly" instead of specifically conducting "separate" annual Reactive Resource assessments.
Response:	
Hydro-Québec TransEnergie Roger Champagne	In VAR-003 Section R 2 . 2 the assessment should be optionally conducted "jointly" by planning authority and transmission planner instead of specifically conducting "separate" annual Reactive Resource assessments.
Response:	
SERC EC Planning Standards (G3) Dominion	(2) In VAR-003 Levels of Non-Compliance section 2.4.1 insert the words (evidence of a) after (No) to provide a way to assess M1.

John Loftis	
Response:	
We Energies Howard Rulf	None
City Water, Light & Power Karl Kohlrus	None
British Columbia Transmission Corp. Thomas Fung	None
Tennessee Valley Authority (G1)	None
Comision Electricidad de Federale Jesus Moya Vazquez	None
Mid-Atlantic Area Coordinating Council John Horakh	Looks ok.
Tennessee Valley Authority (G1)	None
Salt River Project Michael Pfeister	None
FirstEnergy Raymond Morella	None

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

Summary Consideration:

Commenter	Yes	No	Comment
Dynegy Generation Greg Mason		✓	MOD 13 - The effective date needs to be extended from 2/1/07 to 2/1/08 to give entities the necessary time to locate and search through historical records to verify the required generator data.
Response:			
Comision Electricidad de Federale Jesus Moya Vazquez WECC Reliability Subcommittee (G11) Southern California Edison Mohan Kondragunta		✓ ✓ ✓	Implementation dates of August 1, 2007 make it difficult to include in 2007's compliance enforcement program. It is proposed that the implementaion date for these standards be moved out to January 1, 2008.
Response:			
ISO New England, Inc. Kathleen Goodman		✓	The proposed effective date for TOP-002-1 is not shown in the implementation plan. The drafting team needs to better match the effective dates with those shown either for Anticipated Actions or Proposed Effective Date. Please refer to the previous comments.
Response:			
Southern Co Generation (G6)		✓	We agree with the proposed plan with one exception - We recommend Field Testing of VAR-002-1. (See our response to Question 6 on VAR-002-1 Levels of Non-Compliance for details.)
Response:			
Southern Co Services (G5)		✓	Under VAR-002, we feel that the provisions under R.3 seem very reasonable.
Response:			
Mid-Atlantic Area Coordinating	✓		The reference to May 1, 2006 in the last sentence before the table is misleading. I believe the projected Board Adoption Date is August 1, 2006. The six months or one year allowance before the Effective Date is

Commenter	Yes	No	Comment
Council John Horakh			needed to insure that compliance can be achieved.
Response:			
FirstEnergy Raymond Morella	✓		However, the reference to May 1, 2006 in the last sentence before the table is confusing based on the dates/comments in the table.
Response:			
U.S. Army Corps of Engineers Karl Bryan	✓		The implementation plan for TOP-002-1 is fine, but the layout of the regulation is not very concise. Recommend the regulation be broken down into subparts where the subparts only deal with the requirements and metrics for a specific entity.
Response:			
FRCC (G12)	✓		No additional comments.
Tennessee Valley Authority (G1)	✓		None
ISO/RTO Council (G10)	✓		
NPCC CP9, Reliability Standards Working Group (G8)	✓		
U.S Bureau of Reclamation Jay Seitz	✓		
Pepco Holdings, Inc. Affiliates (G9)	✓		
Dominion John Loftis	✓		
Ameren John Sullivan	✓		
City Water, Light & Power Karl Kohlrus	✓		

Commenter	Yes	No	Comment
SERC EC Planning Standards (G3)	✓		
Bonneville Power Administration Lynn Aspaas	✓		
Midwest Reliability Organization (G7)	✓		
PJM Interconnection, L.L.C. Mark Kuras	✓		
NERC Standards Evaluation Subcommittee Bill Bjorquez – ERCOT	✓		
American Transmission Co. Peter Burke	✓		
Salt River Project Michael Pfeister	✓		
Hydro-Québec TransEnergie Roger Champagne	✓		
Independent Electricity System Operator Ron Falsetti	✓		
Tennessee Valley Authority (G1)	✓		
Bonneville Power Admin. – PBL			None

Commenter	Yes	No	Comment
Rebecca Berdahl			
We Energies Howard Rulf			None
British Columbia Transmission Corp. Thomas Fung			None
NERC Wind Generator Task force Mahendra Patel			None

8. Please provide any other comments on this set of standards that you haven't already provided, including any comments you have on any of the issues highlighted in the associated Background Information for Set Two of the Phase III & IV Standards.

Summary Consideration:

Commenter	Comment
Tennessee Valley Authority (G1)	TVA concurs with the drafting teams recommendation to allow field testing of MOD-026-1 & MOD-027-1.
Response:	
Mid-Atlantic Area Coordinating Council John Horakh	Good job overall by the Drafting Team.
Response:	
NERC Standards Evaluation Subcommittee Bill Bjorquez – ERCOT	The SES commends the Set 2 Phase III/IV Drafting Team for its efforts and stands ready to support these standards with the consideration of the previous comments.
Response:	
Tennessee Valley Authority (G1)	TVA concurs with the drafting teams recommendation to allow field testing of MOD-026-1 & MOD-027-1.
Response:	
Dynegy Generation Greg Mason	1. With regard to field testing of MOD-026, each Generation Owner should have the option of doing a field test on a unit but not be required to complete a field test for at least one unit.Such a requirement for a field test seems to conflict with R1.2 of MOD-026-1 which allows multiple verification methods,of which field testing is one of those methods.
Response:	
SERC EC Planning Standards (G3)	References in a standard to another standard should not include the Revision number.
Response:	
U.S. Army Corps of Engineers Karl Bryan	For any requirement in a reliability standard, there should be at least one measurement. This would make the job of complying witht the reliability standard easier for the entity as well as make the job of the compliance team easier.
Response:	

Commenter	Comment
City Water, Light & Power Karl Kohlrus	For TP-002-1 in R15 capitalize "Generator".
Response:	
WECC Reliability Subcommittee (G11) Southern California Edison Mohan Kondragunta	TOP-002 Before any requirement can be implemented, there needs to be a measure. For example, VAR-001-1 has 13 requirements but only 4 measures.
Response:	
FRCC (G12)	TOP-002-1 is incomplete and should be modifed and posted for comments. It needs to have Measures and Compliance items added.
Response:	
FirstEnergy Raymond Morella	It is unclear why the Drafting Team added TOP-002-1 to the Draft 2, Set 2 issue of the Phase III-IV Standards. It is our understanding that the TOP-002-1 standard was not included in any prior release of the draft Phase III-IV Standards. It is recommended that this be removed from the Phase III-IV group and move through the NERC Standard Development process on its own. Also, there is no reference to the TOP-002-1 standard in your questioning above. Furthermore, the TOP-002-1 recommended changes for R14 are NOT agreed to.
Response:	
Bonneville Power Admin. – PBL Rebecca Berdahl	Each requirement must be supported by a measurement. Those standards that have requirements without measurements need revising. TOP-002 is not included as one of the standards set for comment in this comment form. Please clarify.
Response:	
Bonneville Power Administration Lynn Aspaas	TOP-002 Requirement R8 states "... shall plan to meet voltage and/or reactive limits, ..." It would make more sense for this sentence to refer to "requirements" rather than "limits". Requirement R16.2 - It seems an example that would better reflect system operations would be "system operating limits" rather than "transmission facility ratings."
Response:	
Ameren John Sullivan	TOP-002-1: At present, a number of system studies are performed at the regional level. Therefore, the first sentence of Requirement R11 should read: The transmission operator or designee shall perform seasonal, next-day, and current-day bulk electric system studies to determine SOLs.
Response:	

Commenter	Comment
ISO New England, Inc. Kathleen Goodman	ISO NE agrees with the premise to have design data for new or refurbished excitation systems provided at least one year prior to the in-service date with updated data provided within 2 weeks of the unit being in-service. There should also be a requirement to provide updated data within 2 weeks of changes.
Response:	
Midwest Reliability Organization (G7)	EOP-005: the MRO does not see the need to move IV.A.M2 and M3 into a new version 1 standard. MOD-026 and MOD-027 Levels of Non-Compliance: Failure to comply on the administrative details listed in M1, M2 and M3 should not invoke a high non-compliance level, i.e., greater than level 2. However, the RRO not having a model verification process or the Generator Owner not providing verified models should invoke a high non-compliance level. Also, since the RRO is providing the verification process perhaps it should be involved in determining acceptability of the models and a related compliance level. VAR-003: as per the MRO draft 1 comments the MRO recommends that VAR-003 be merged with the TPL set of standards.
Response:	
NERC Wind Generator Task force Mahendra Patel	When wind generation is incorporated into NERC standards, the standards should generally refer to wind generator plants, rather than individual wind generators. Wind generator plants comprise a complete system, rather than individual units.
Response:	

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	August 1, 2007 (One year after BOT adoption)	Time needed for TOP to update cranking paths and to do testing or simulation with new emphasis on blackstart elements of restoration plans.
MOD-013 Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures	February 1, 2007 (6 months beyond BOT adoption)	Time needed to reach agreement on the addition to the RRO's procedures.
MOD-016 Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management	February 1, 2007 (6 months beyond BOT adoption)	Time needed for RRO to modify & distribute existing procedures.
VAR-001 Voltage and Reactive Control	February 1, 2007 (6 months beyond BOT adoption)	Time needed for TOP to update its documentation and, if needed, develop new procedures.
VAR-002 Generator Operation for Maintaining Network Voltage Schedules	August 1, 2007 (6 months beyond VAR-001)	Delay allows responsible entities time to conform to associated requirements in VAR-001 – this may involve developing new procedures.
VAR-003 Assessment of Reactive Power Resources	August 1, 2007 (One year after BOT adoption)	Time needed for PA and TP to formalize methodology and criteria for reactive assessments and then to document the results of associated assessments.

Modification to Version 0 TOP-002 based on adoption of VAR-002

The drafting team recommends that the following requirement be modified when VAR-002 becomes effective:

Version 0 TOP-002	Proposed VAR-002
R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to: **R14.1.** Changes in real ~~and reactive~~ output capabilities. ~~**R14.2.** Automatic Voltage Regulator status and mode setting.~~	**R3.** Each Generator Operator shall notify its associated Transmission Operator within 30 minutes of any of the following. If unable to notify the Transmission Operator within 30 minutes, the Generator Operator shall have documentation to support the reasons for not making the notification within 30 minutes. **R3.1.** A status change on any synchronous generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer. **R3.2.** A status change on any other Reactive Power resources under the Generator Operator's control. **R3.3.** A voltage or Reactive Power schedule for a generator is not maintained.

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, MOD-016-1 is a modification of Version 0's MOD-016-0. MOD-016-0 has two requirements for the Regional Reliability Organization and the Planning Authority. The Regional Reliability Organization and Planning Authority are both responsible for compliance with both of the requirements in MOD-016-0 until February 1, 2007 when MOD-016--1 will replace MOD-016-0.

Standard Number	Req. Number	BA	DP	GO	GOP	LSE	PA	PSE	RC	RP	RRO	RSG	TO	TOP	TP	TSP	NERC_Net
EOP-005	1													TOP			
EOP-005	2													TOP			
EOP-005	3													TOP			
EOP-005	4													TOP			
EOP-005	5	BA												TOP			
EOP-005	6	BA												TOP			
EOP-005	7	BA												TOP			
EOP-005	8													TOP			
EOP-005	9													TOP			
EOP-005	10													TOP			
EOP-005	10.1													TOP			
EOP-005	11	BA												TOP			
EOP-005	11.1	BA												TOP			
EOP-005	11.2	BA												TOP			
EOP-005	11.3	BA															
EOP-005	11.4													TOP			
EOP-005	11.5													TOP			
EOP-005	11.5.1													TOP			
EOP-005	11.5.2													TOP			
EOP-005	11.5.3													TOP			

Standard Number	Req. Number	BA	DP	GO	GOP	LSE	PA	PSE	RC	RP	RRO	RSG	TO	TOP	TP	TSP	NERC_Net
EOP-005	11.5.4													TOP			
MOD-013	1										RRO						
MOD-013	1.1										RRO						
MOD-013	1.2										RRO						
MOD-013	1.2.1										RRO						
MOD-013	1.2.2										RRO						
MOD-013	1.3										RRO						
MOD-013	1.4										RRO						
MOD-013	1.5										RRO						
MOD-013	2										RRO						
MOD-016	1						PA				RRO						
MOD-016	1.1						PA				RRO						
MOD-016	1.2						PA				RRO						
MOD-016	2										RRO						
MOD-016	3						PA										
MOD-026	1										RRO						
MOD-026	1.1										RRO						
MOD-026	1.2										RRO						
MOD-026	1.3										RRO						
MOD-026	1.4										RRO						

Standard Number	Req. Number	BA	DP	GO	GOP	LSE	PA	PSE	RC	RP	RRO	RSG	TO	TOP	TP	TSP	NERC_Net
MOD-026	1.4.1										RRO						
MOD-026	1.4.2										RRO						
MOD-026	1.4.3										RRO						
MOD-026	1.4.4										RRO						
MOD-026	1.4.5										RRO						
MOD-026	1.4.6										RRO						
MOD-026	1.4.7										RRO						
MOD-026	2										RRO						
MOD-026	3			GO													
MOD-027	1										RRO						
MOD-027	1.1										RRO						
MOD-027	1.2										RRO						
MOD-027	1.3										RRO						
MOD-027	1.4										RRO						
MOD-027	1.4.1										RRO						
MOD-027	1.4.2										RRO						
MOD-027	1.4.3										RRO						
MOD-027	1.4.4										RRO						
MOD-027	2										RRO						
MOD-027	3			GO													

Standard Number	Req. Number	BA	DP	GO	GOP	LSE	PA	PSE	RC	RP	RRO	RSG	TO	TOP	TP	TSP	NERC_Net
VAR-001	1													TOP			
VAR-001	2													TOP			
VAR-001	3													TOP			
VAR-001	4													TOP			
VAR-001	5													TOP			
VAR-001	6							PSE									
VAR-001	7													TOP			
VAR-001	7.1													TOP			
VAR-001	8													TOP			
VAR-001	9													TOP			
VAR-001	10													TOP			
VAR-001	10.1													TOP			
VAR-001	11													TOP			
VAR-001	12													TOP			
VAR-001	13													TOP			
VAR-002	1				GOP												
VAR-002	2				GOP												
VAR-002	2.1				GOP												
VAR-002	3				GOP												
VAR-002	3.1				GOP												

Standard Number	Req. Number	BA	DP	GO	GOP	LSE	PA	PSE	RC	RP	RRO	RSG	TO	TOP	TP	TSP	NERC_Net
VAR-002	3.2				GOP												
VAR-002	3.3				GOP												
VAR-002	4			GO													
VAR-002	4.1			GO													
VAR-002	4.1.1			GO													
VAR-002	4.1.2			GO													
VAR-002	4.1.3			GO													
VAR-002	4.1.4			GO													
VAR-002	5			GO													
VAR-002	5.1				GOP												
VAR-003	1						PA								TP		
VAR-003	2						PA								TP		
VAR-003	2.1						PA								TP		
VAR-003	2.2						PA								TP		
VAR-003	3						PA								TP		

Attachment 5

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

December 7, 2005

Ms. Linda Campbell
Director of Reliability
Florida Reliability Coordinating Council
1408 N. Westshore Boulevard
Suite 1002
Tampa, Florida 33607-4512

Dear Ms. Campbell:

Phase III-IV Standards — Set Two Field-Testing Recommendation

I am writing in response to your letter dated October 31, 2005, regarding the need to field-test any of the second set of Phase III-IV standards, which have been posted for public comment through December 3, 2005.

With input from the Compliance and Certification Managers Committee (CCMC), NERC has reviewed the following standards to determine whether they should undergo field-testing prior to ballot:

- MOD-016 Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable DSM
- MOD-026 Verification and Models and Data for Generator Excitation System Functions
- MOD-027 Verification of Generator Unit Frequency Response
- VAR-001 Voltage and Reactive Control
- VAR-002 Generator Operation for Maintaining Network Voltage Schedules
- VAR-003 Assessment of Reactive Power Resources
- EOP-005 System Restoration Plans

As a result, I am recommending that the following two standards be field-tested prior to ballot:

- MOD-26 Verification and Models and Data for Generator Excitation System Functions
- MOD-27 Verification of Generator Unit Frequency Response

These standards would benefit from a field-test to verify that the requirements and measures are appropriate and can be objectively measured.

If you have any further questions, please do not hesitate to contact Mike DeLaura (mike.delaura@nerc.com), Ed Ruck (Ed.Ruck@nerc.net), or me.

Sincerely,

David W. Hilt
Vice President–Compliance

Cc: Michael A. DeLaura, Manager–Compliance Review, NERC
Gerry Cauley, Director–Standards,NERC
Maureen Long, NERC
Mark Ladrow, Manager–Standards, NERC
Robert Millard, Standard Drafting Team Chair
Compliance and Certification Managers Committee
Edward Ruck, Regional Compliance Program Coordinator

Field Test Plan for PRC-024	
Time	**Action**
2 weeks after SAC approval	Issue letter to Regional Managers asking for field test volunteers – at least 3 Regions are needed, representing at least 2 Interconnections; within each Region the volunteer cluster must include the RRO; at least one Generator Owner and at least one Transmission Owner that would be expected to coordinate their protection systems
4 weeks after SAC approval	SDT receives Regional responses
8 weeks after SAC approval – official start date; 1 month after volunteers identified	Kick-off meeting with volunteers to: Establish contact information, schedule, standard requirements, field test reporting requirements; goal is to attempt to meet R1 through R3 within 6 months
1 month after test start date and each month thereafter	Progress Report via Web Ex; report to SAC
6 months after test start date	Kick-off meeting to add Generator Owners and Transmission Owners to test ; goal is to attempt to meet R7, reporting progress and problems monthly for 6 months
Each month thereafter	Progress Report via Web Ex; report to SAC
12 months after test start date	CCMC to verify RRO, Generator Owner and Transmission Owner compliance with M1 and M4
13 months after test start date	Curtail test; post results; revise standards if needed to address test results; post revised standards for review and comment

From the Planning Committee:

The PC endorses the field test and requests the SAC's field test group to work with the PC's IDWG/SPCTF on field test activities and their relationship to Blackout Recommendations TR-21 and TR-8 (if appropriate).

(Look beyond just relay settings and the entire protection and control systems.)

From the SAC:

The SAC met December 8-9 and approved the field test plan conditioned upon inviting the SPCTF and IDWG to participate in the field test as appropriate.

Standard and SAR Development Progress Report

Standard Number(s): PRC-020 through PRC-022; PRC-003 through PRC-005; PRC-002 and PRC-018; MOD-024; MOD-025; PRC-019; PRC-024

Standard Title: Phase III & IV

Drafting Team Chairman: Bob Millard

Facilitator: Maureen Long

Report Date: December 13, 2005

Development Steps Completed:

Completed Development Steps	Completion Date
Briefly list the major numbered steps in the standards process that have been completed. Identify each draft of the SAR and proposed standard that was previously posted, including the dates.	
Post 1st draft of standards for 45 day review.	6/5/05
Post 2nd draft of standards for 45 day review.	10/15/05
Post 3rd draft of the 12 standards – 2 posted for comment; 2 for field test; 8 for pre-ballot review	current

Current Status:

Provide a brief description of the current status of the project – what is the status of the draft, etc.

There are 12 standards in this set – 2 are posted for comment through Jan 17, 2006. Two must be field tested and 8 are posted for a pre-ballot review.

Any Reasons for Delay or Inactivity

Describe any challenges or delays the drafting team is facing, or any reason for inactivity.

When Phase III & IV Measures were removed from Version 0, it was on the assumption that the measures were ‘close’ to being finalized, but needed a bit of additional work before achieving stakeholder consensus. While this is true for a few of these standards, many Measures have not been translated into new Reliability Standards because they identify a ‘desirable’ practice rather than performance needed for reliability. Some Measures cannot be implemented because there are no identified, readily-available methods to achieve that measure. Thus, the scope of the SARs was reduced based on stakeholder comments.

Future Development and Posting Schedule:

Action	Target Date	Confidence Level	Notes
Post Consideration of Comments & 2 Standards for 30-day Pre-ballot review	2/1/06	Medium	Assumes consensus has been achieved on the draft standards (PRC-002 and PRC-018)
Field testing for 2			To be determined – One field test was

standards (PRC-019 and PRC-024)			approved, the other field test needs to be developed and approved by SAC in Jan
Ballot eight standards	1/3/06	High	
Ballot two standards	3/2/06	Medium	
BOT adoption			Dates to be determined by BOT

Last Meeting:	**Next Meeting:**
Date: Oct 17 Type: Face-to-face Meeting Number in attendance: 17 Notes:	Date: Jan 4-5 Type: Face-to-face Meeting Notes: Work on field test for PRC-019 and respond to comments on Set Two of Phase III & IV

List Changes to the Roster:

Standard and SAR Development Progress Report

Standard Number(s): EOP-005; MOD-013; MOD-016; MOD-026; MOD-027; VAR-001 through VAR-003

Standard Title: Phase III & IV

Drafting Team Chairman: Bob Millard

Facilitator: Maureen Long

Report Date: December 13, 2005

Development Steps Completed:

Completed Development Steps	Completion Date
Briefly list the major numbered steps in the standards process that have been completed. Identify each draft of the SAR and proposed standard that was previously posted, including the dates.	
Post 1st draft of standards for 45 day review.	6/5/05
Post 2nd draft of standards for 45 day review.	12/5/05

Current Status:

Provide a brief description of the current status of the project – what is the status of the draft, etc. The drafting team will consider the comments on the second posting of Set Two during a January meeting.

Any Reasons for Delay or Inactivity

Describe any challenges or delays the drafting team is facing, or any reason for inactivity. When Phase III & IV Measures were removed from Version 0, it was on the assumption that the measures were 'close' to being finalized, but needed a bit of additional work before achieving stakeholder consensus. While this is true for a few of these standards, many Measures have not been translated into new Reliability Standards because they identify a 'desirable' practice rather than performance needed for reliability. Some Measures cannot be implemented because there are no identified, readily-available methods to achieve that measure. Thus, the scope of the SARs was reduced based on stakeholder comments.

Future Development and Posting Schedule:

Action	Target Date	Confidence Level	Notes
Field test (MOD-026 and MOD-027)			Field tests need to be developed and approved
Post for 3rd comment period	1/15/06	Medium	Some standards may need another posting
30-day pre-ballot review	2/15/06	Medium	Some standards may be ready to ballot
Ballot	5/20/06		

BOT adoption				

Last Meeting:	**Next Meeting:**
Date: September 26-27, 2005 Type: Face-to-face Meeting Number in attendance: 17 Notes: Finalize documents for 2nd posting	Date: Jan 4-5 Type: Face-to-face Meeting Notes: Consider comments on 2nd posting. Prepare a set for a 30-day pre-ballot posting.

List Changes to the Roster: None