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:** ~~November 1, 2005.~~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 demonstrate, through simulation or testing, that its blackstart generating unit(s) can perform the startup functions as stated in the transmission operator's restoration plan. The transmission operator shall perform such simulation or testing at least every five years, and shall provide documentation to the Regional Reliability Organization on request.~~

~~R10.~~R9. The transmission operator shall document the cranking paths~~ or maintain cranking path diagrams~~, including initial switching requirements, ~~associated~~ between each blackstart generating unit and the unit(s) to be ~~cranked~~ 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 in its area are able to perform the functions of the restoration plan.

M2. The transmission operator shall, within 30 calendar days of a request, provide documentation or a diagram showing the number, size and location of system blackstart generating units and the associated Cranking Paths.

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-~~self-certification or audit (periodic, as part of targeted monitoring, or initiated by complaint or event), as determined by the compliance monitor.

2. Levels of Non-Compliance

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

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

2.3. Level 3: ~~The transmission operator did not provide documentation or a diagram showing the number, size and location of system blackstart generating units and the associated Cranking Paths.~~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~~The transmission operator's simulation or test results demonstrating that blackstart generating units can perform their intended functions were not provided, or the results were not compliant with the regional restoration plan.~~

2.4.2 No restoration plan is in place.

2.4.3 No simulation or test results as required in Requirement R10.

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 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
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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

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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-~~0~~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. Proposed Effective Date: ~~April 1~~February 1, 200~~5~~7

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.

~~R1.1.~~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.

~~R1.1.1.~~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.

~~R1.1.2.~~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.

~~R1.2.~~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.

~~R1.3.~~R1.4. Dynamics data representing electrical demand characteristics as a function of frequency and voltage.

~~R1.4.~~R1.5. Dynamics data shall be consistent with the reported steady-state (power flow) data supplied per Reliability Standard MOD-010-0~~ R~~ Requirement 1.

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 R~~Requirement 2.

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 ~~four~~ five areas defined in ~~Reliability Standard MOD-013-0 R~~Requirement 1.

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 R1~~Not applicable~~.

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 ~~two~~ three or more of the ~~four~~ 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 new definitions are proposed for 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 a~~A~~ccurate, actual demand data is ~~needed to ensure that~~available to support assessments and validation of past events and databases. ~~can be performed.~~ 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.

   ~~4.1.~~4.2. Regional Reliability Organization.

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

B. Requirements

R1. The planning authority and regional reliability organization shall ~~develop and maintain a procedure that identifies~~ have documentation identifying the scope and details of the actual and forecast (a) demand data, (b) net energy for load data, and (c) controllable DSM data to be reported for system modeling and reliability analyses. ~~The procedure shall include all of the following:~~

R1.1. The aggregated and dispersed data submittal requirements shall ensure that consistent data is supplied for Reliability Standards TPL-005-0, TPL-006-0, MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-0, MOD 014-0, MOD-015-0, MOD-016-0, 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.** A requirement that each Load-Serving Entity develop a set of actual and forecast customer demand values for use in all its data reporting during a calendar year.~~

~~**R3.** A requirement that each Load-Serving Entity count each customer within its service territory once and only once in developing its actual and forecast customer demand values.~~

~~**R4.** A requirement that each Load-Serving Entity with a controllable DSM program identifies the amounts and locations of customer load designed to be curtailed with that DSM program.~~

~~**R5.** A requirement that each Load-Serving Entity update its actual and forecast customer demand values once each year according to a schedule.~~

~~**R6.** A requirement that each Regional Reliability Organization use the actual and forecast data provided by the Load-Serving Entities in conducting its reliability assessments.~~

~~**R7.** A schedule for each Load-Serving Entity to provide its actual and forecast demand data and the amount of customer load designed to be curtailed with a controllable DSM program to its Planning Authority and Regional Reliability Organization.~~

R2. The regional reliability organization shall distribute its documentation required in Requirement 1 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 regional reliability organization shall distribute its documentation required in 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

~~3.0.~~M1. ~~The Regional Reliability Organization shall distribute its procedure for reporting customer Demand data to all Planning Authorities and Load-Serving Entities that work within its Region within 30 calendar days of approval. The Regional Reliability Organization shall have evidence it provided its actual and forecast customer Demand data reporting procedure within 30 calendar days of approval to each Planning Authority and Load Serving Entity that works within its Regional Reliability Organization. The Regional Reliability Organization's procedure for actual and forecast customer demand data shall contain all items identified in requirements R.1 to R.6.~~The regional reliability organization's documentation for actual and forecast customer demand data shall contain all items identified in Requirement 1.

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 requirement 3.

~~C.~~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 procedure.

For the ~~auditor~~compliance monitor: Three years of audit information.

1.4. Additional Compliance Information

The regional reliability organization 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.~~Documentation does not address completeness and double counting of customer data.

2.2. Level 2: ~~The procedure did not address one of the elements in requirement R1.~~Documentation did not address one of the three types of data required in Requirement 1 (demand data, net energy for load data, and controllable DSM data).

2.3. Level 3: ~~Not applicable.~~No evidence documentation was distributed as required.

2.4. Level 4: Either the ~~procedure~~ documentation did not address two ~~or more~~ of the three types of data required ~~elements in requirement~~in R1 (demand data, net energy for load data, and controllable DSM data), or there was no ~~procedure.~~documentation.

~~D.~~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.M4 and II.B.M6, which were not included in the approval Version 0 reliability standards because they required further work.

Development Steps Completed:

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

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No new definitions are proposed for this standard.

A. Introduction

1. **Title:** **Verification ~~and~~ of Model~~sing~~ and Data for ~~of~~ Generator Excitation System ~~s and Voltage Control~~Functions**

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

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

4. **Applicability**

   4.1. Regional Reliability Organization.

   4.2. Generator Owner.

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

B. Requirements

R1. The regional reliability organization shall establish and maintain procedures to address verification of 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 ~~within 30 calendar days of a request, provide to the~~ regional reliability organization's procedures for verifying and reporting its models and ~~and applicable Transmission Planner(s)~~ data associated with the generator excitation system functions ~~(including voltage regulator controls, limiters, compensators, and power system stabilizers, if applicable), in accordance with Regional Reliability Organization requirements~~per requirement 1.

~~**R2.** The Generator Owner shall verify the data used in dynamic models for excitation systems (including power system stabilizers and other devices, if applicable) in accordance with Regional Reliability Organization requirements.~~

~~**R3.** The Generator Owner shall, within 30 calendar days of a request, provide to the Regional Reliability Organization and applicable Transmission Planner(s) the results of excitation system model and data verification, including but not limited to the following information:~~

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

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

~~**R3.3.** under and over excitation limiters.~~

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

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

~~**R3.6.** Power system stabilizers, if applicable.~~

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

~~**R4.** The Generator Owner shall provide design data for new or refurbished excitation systems prior to the in-service date as required by the Regional Reliability Organization procedure and provide updated data once the unit is in service. Open circuit test response chart recordings shall be provided showing generator field voltage and generator terminal voltage.~~

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

C. Measures

M1. The regional reliability organization shall have available for inspection a procedure for the verification and reporting of models and data associated with its generator excitation system functions in accordance with Requirement 1.

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.

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

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~~and applicable~~ transmission planner and planning authority. ~~(s) with verification results for the excitation system functions (including voltage regulator controls, limiters, compensators, and power system stabilizers, if applicable).~~

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.

~~Generator Owner shall retain assessments for two years.~~

The compliance monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The regional reliability organization and generator owner shall each demonstrate compliance through self~~-~~certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the compliance monitor.

2. Levels of Non-Compliance (To be added following field testing.)

~~**2.1.Level 1:** Generator voltage regulator controls and limit function information, were provided but were incomplete in one area as specified in MOD-026 R1, R2 and R5.~~

~~**2.2.Level 2:** Not applicable.~~

~~**2.3.Level 3:** Generator Owner provided design data for new or refurbished excitation systems prior to the in-service date but was incomplete as required by the Regional Reliability Organization procedure or provided incomplete updated data once the unit is in service as specified in MOD-026 R3 and R4.~~

~~**2.4.Level 4:** Generator Owner did not verify the data used in dynamic models for excitation systems (including power system stabilizers and other devices, if applicable) in accordance with Regional Reliability Organization requirements as specified in MOD-026 R2.~~

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 ~~and Status~~ of Generator Unit Frequency Response**

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

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

4. **Applicability**

   4.1. Regional Reliability Organization.

   4.2. Generator Owner.

5. **Proposed Effective Date:** ~~October 1, 2005~~To be Determined.

B. Requirements

R1. The regional reliability organization shall establish and maintain procedures to address verification and status of generator unit frequency response (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 ~~provide data to the Transmission Planner, Transmission Operator, and~~ follow its regional reliability organization's procedure for verifying and reporting its ~~on how the unit speed and real power output are expected to change in response to frequency transients~~generator unit frequency response per Requirement 1~~, in accordance with Regional Reliability Organization requirements~~.

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

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

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

C. Measures

M1. The regional reliability organization shall have available for inspection a procedure for verifying and reporting the status of generator unit frequency response in accordance with Requirement 1.

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, transmission planner, and transmission operator with the information required in R1 ~~and R2 within 30 calendar days of a request~~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.)

~~**Level 1:** Method of verification of the generator frequency response was provided but was missing some of the information required in MOD-027 R2.2.~~

~~**Level 2:** Not applicable.~~

~~**Level 3:** Data on a how a unit is expected to change in response to frequency transients was provided but was missing some of the information required in MOD-027 R1.~~

~~**Level 4:**~~

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

~~Method of the verification of the generator frequency response was not provided, or~~

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

~~Information on non-functioning or blocked speed/load governor controls, or controls that influence speed/load governor controls was not provided.~~

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 TOP-002 modified to include a translation of planning measures 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 Phase III & IV standards 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:** **Normal Operations Planning**

2. **Number:** TOP-002-~~0~~1

3. **Purpose:** Current operations plans and procedures are essential to being prepared for reliable operations, including response for unplanned events.

4. **Applicability**

   4.1. Balancing Authority.

   4.2. Transmission Operator.

   4.3. Generation Operator.

   4.4. Load Serving Entity.

   4.5. Transmission Service Provider.

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

B. Requirements

R1. Each balancing authority and transmission operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each balancing authority and transmission operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.

R2. Each balancing authority and transmission operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.

R3. Each load serving entity and generator operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host balancing authority and transmission service provider. Each balancing authority and transmission service provider shall coordinate its current-day, next-day, and seasonal operations with its transmission operator.

R4. Each balancing authority and transmission operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring balancing authorities and transmission operators and with its reliability coordinator, so that normal interconnection operation will proceed in an orderly and consistent manner.

R5. Each balancing authority and transmission operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling, and demand patterns.

R6. Each balancing authority and transmission operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.

R7. Each balancing authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single contingency.

R8. Each balancing authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.

R9. Each balancing authority shall plan to meet interchange schedules and ramps.

R10. Each balancing authority and transmission operator shall plan to meet all system operating limits (SOLs) and Interconnection reliability operating limits (IROLs).

R11. The transmission operator shall perform seasonal, next-day, and current-day bulk electric system studies to determine SOLs. Neighboring transmission operators shall utilize identical SOLs for common facilities. The transmission operator shall update these bulk electric system studies as necessary to reflect current system conditions; and shall make the results of bulk electric system studies available to the transmission operators, balancing authorities (subject confidentiality requirements), and to its reliability coordinator.

R12. The transmission service provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional total transfer capability and available transfer capability calculation processes.

R13. At the request of the balancing authority or transmission operator, a generator operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the balancing authority or transmission operator operating personnel as requested.

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.~~

R15. generation operators shall, at the request of the balancing authority or transmission operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).

R16. Subject to standards of conduct and confidentiality agreements, transmission operators shall, without any intentional time delay, notify their reliability coordinator and balancing authority of changes in capabilities and characteristics including but not limited to:

R16.1. Changes in transmission facility status.

R16.2. Changes in transmission facility rating.

R17. Balancing authorities and transmission operators shall, without any intentional time delay, communicate the information described in ~~the r~~Requirements ~~R~~1 to ~~R~~16 above to their reliability coordinator.

R18. Neighboring balancing authorities, transmission operators, generator operators, transmission service providers~~,~~ and load serving entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.

R19. Each balancing authority and transmission operator shall maintain accurate computer models utilized for analyzing and planning system operations.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata

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

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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:** ~~November 1, 2005~~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 Requirement 5 and Requirement 7.1.

R3. Each transmission operator shall acquire sufficient reactive resources within its area to ~~ensure~~ protect ~~adequate~~ 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~~ reactive power schedule to be maintained by each non-exempt synchronous generator. The ~~ransmission~~ transmission operator ~~, within the reactive capability of the unit, at a specified bus and~~ shall provide ~~this information~~the voltage or reactive power schedule to the associated generator operator.

~~**R3.1.**Each Transmission Operator shall maintain a list of synchronous generators that are required to follow a voltage or Reactive schedule and shall provide each Generator Operator with its voltage or reactive schedule.~~

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 ~~notify~~ direct the generator operator ~~of a voltage schedule or reactive output~~ to maintain or change either its voltage schedule or its reactive power schedule. ~~Interconnection and generator stability.~~

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.

~~**R10.** Each Generator Operator shall provide information to its Transmission Operator on the status of all generation reactive power resources, including the status of each voltage regulator and power system stabilizer.~~

~~**R11.** When a generator's voltage regulator is out of service, the Generator Operator shall maintain the generator field excitation at a level to maintain Interconnection and generator stability.~~

~~**R12.** Each Transmission Operator with synchronous generation connected to its system shall provide to the Generator Operator procedures that shall:~~

~~**R13.** Require the Generator Operator to provide summary reports showing the number of hours each synchronous generator did not operate in the automatic voltage control mode during a specified time period.~~

~~**R14.** Require the Generator Operator to provide logs containing the date, duration, and reason for each period when a synchronous generator was not operated in the automatic voltage control mode.~~

~~**R15.** Require the Generator Operator to retain the above information for 12 rolling months.~~

~~**R16.** Specify criteria by which generators are to be exempted from the above requirements.~~

~~**R17.** The Transmission Operator shall have, and shall provide to the Generator Operator, procedures instructing Generator Operators to provide tap settings, available tap ranges, and impedance data for generator step-up and auxiliary transformers.~~After consultation with the Generator Owner regarding necessary step-up transformer tap changes,

R12. ~~When mutually agreed to tap changes are necessary,~~ The transmission operator shall provide documentation to the generator ~~Operator~~ owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes.

~~**R18.1.** The Transmission Operator procedures shall address generating unit exemption criteria (including any that may apply to nuclear units).~~

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 Requirement 5 to each generator operator it requires to follow such a schedule.

~~**M1.** For Reliability Standard VAR-001-1 R3., the Transmission Operator shall have documentation of the voltage or reactive schedule provided to the Generator Operator and shall provide the~~

~~information to the Regional Reliability Organization and NERC within 30 calendar days of a request.~~

M2. The transmission operator shall have evidence 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 Requirement 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 Requirement 11.

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

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

~~C.~~D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

The transmission operator shall retain current and previous version documentation.

1.4. Additional Compliance Information

The transmission operator shall demonstrate compliance through self-~~-~~certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the compliance monitor.

2. Levels of Non-Compliance

2.1. Level 1: ~~Transmission Operator has procedures for Generator Operators to follow but they do not include all aspects of Requirements R10 or R11~~ No documentation to show that owners of generating units that are exempt from following voltage or reactive power schedules were notified of this exemption.

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

2.1.1 No documentation to show that directives were issued in accordance with Requirement 7.1.

2.1.2 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 Requirement 11.

~~2.1. Incomplete list of exempt synchronous generators was provided per requirements R3 or R10.~~

2.2. **Level 3:** Voltage or reactive ~~P~~power schedules do not exist for all generating units required to follow the schedules.

~~2.2. Incomplete documentation of the requested voltage or reactive schedule was provided per requirements R3 or R10.~~

2.3. **Level 4:** No evidence voltage or reactive power schedules were provided to generator owners.

~~2.3. Transmission Operator has no documentation or procedures addressing requirements R3, R10, or R11.~~

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 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~~limits in real time~~ to protect equipment and the reliable operation of the interconnection.

4. **Applicability**

   4.1. Generator Operator.

   4.2. Generator Owner.

5. **Proposed Effective Date:** ~~November 1, 2005~~August 1, 2007.

B. Requirements

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

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.

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

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 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.

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

~~**R2.**Each Generator Operator shall maintain the synchronous generator voltage or reactive output as specified by the Transmission Operator, unless otherwise approved by the Transmission Operator.~~

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

R5. ~~When mutually agreed with the Transmission Operator, the Generator Operator shall change~~ step-up transformer tap ~~positions~~ changes, the generator owner shall ensure that the transformer tap positions are changed according to the ~~documentation~~ 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. ~~within a mutually agreed upon time frame.~~

~~**R4.**The Generator Operator shall provide the tap settings and the available tap ranges and impedance data for generator step-up and auxiliary transformers to the Transmission Operator, Regional Reliability Organization, and NERC, within five business days of a request.~~

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 Requirements 3.1 through 3.3.

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

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

M4. The generator ~~Operator~~ owner shall have evidence it provided its associated transmission operator and transmission planner with information on its ~~has documentation of~~ step-up transformers and auxiliary transformers as required in Requirements 4.1.1 through 4.1.4.~~tap~~

~~settings and changes, available tap ranges, and impedances for generator step-up and auxiliary transformers.~~

M5. The generator owner shall have evidence that its step-up transformer taps were modified per the transmission operator's documentation as required in Requirement 5.

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 Measures 1 through 3 for a rolling 12 months. ~~a written log of this information for 12 rolling 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.

~~1.~~2. Levels of Non-Compliance for Generator Operator

~~1.1.~~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 Requirements 3.1 through 3.3.

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

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

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

2.2.1 ~~Logs indicate incidents,~~ Failed to meet the voltage or reactive power schedule, subsequent to the 30-minute notification period, ~~of synchronous generator operation off the voltage or reactive schedule, or operation without automatic voltage control,~~ for an accumulated time of more than 8 but less than 16 unit-hours for an individual generator without transmission operator ~~concurrence~~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 Requirements 3.1 through 3.3.

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 Requirements 3.1 through 3.3.

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 Requirements 3.1 through 3.3.

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 Requirements 4.1.1 through 4.1.4.

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.

~~2.2.1Logs of synchronous generator operation off the voltage or reactive schedule were not provided, or the logs indicate incidents, subsequent to the 30-minute notification period, of operating off the voltage or reactive schedule or operation without automatic voltage control for an accumulated time of more than 24 unit-hours for an individual generator without Transmission Operator concurrence.~~

~~2.2.2Generator operator did not change tap settings as requested by the Transmission Operator during the mutually agreed upon time frame.~~

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

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, ~~with a balance between~~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:** ~~November 1, 2005~~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 Reliability Standards 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 perform this assessment at least once every five years.~~, or as required by changes in system conditions.~~

R3. The transmission planner and planning authority shall each document its assessments of Reactive Power resources and shall provide these assessments to the regional reliability organization ~~and NERC when~~upon request~~ed~~.

C. Measures

M1. The transmission planner and planning authority shall each have evidence that it developed~~, and reviewed within the previous five years,~~ a method and criteria for assessing the adequacy of reactive power resources in accordance with ~~VAR-003 R~~Requirement 1 and shall provide this evidence to its regional reliability organization ~~and NERC~~ within 30 calendar days of a request.

M2. The transmission planner and planning authority shall each have evidence it conducted an assessment of its reactive power resources within the past five years or as required by system conditions, in accordance with ~~VAR-003 R~~Requirement 2.

M3. The transmission planner and planning authority shall each have evidence it provided documentation of the results of its most recent reactive power resource assessment to its regional reliability organization within 30 calendar days of a request.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

The transmission planner and planning authority shall retain the ~~current~~ 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~~incomplete in one area~~.

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

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

2.4.1 ~~The Transmission Planner or Planning Authority did not provide evidence that it has a~~ No method and criteria for assessing adequate static and dynamic reactive power requirements~~, or~~.

2.4.2 No evidence of an ~~As~~assessment~~s~~ of static and dynamic reactive power ~~resources were incomplete in more than one area~~requirements within the past 5 years.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking