NERC

PLANNING STANDARDS

North American Electric Reliability Council

April 2004 Version of All Planning Standards

Terms and Their Definitions
As Used in the NERC Planning Standards

Analysis (Study) — an examination or simulation of an event, component, process, or activity and its elements and their relationship to determine if objectives, goals, or performance is achieved.

Area Predetermined — the particular extent, in electrical or geographic terms, decided in advance for the scope of operation or impact.

Assessment — an evaluation that allows a conclusion to be reached or a decision to be made that may or may not involve an analysis or simulation.

At All Demand Levels — the entire range of projected electrical power that a system may be required to deliver.

Available on Request — can be provided when asked through proper means under the designated format within the agreed upon time frame (negotiated or designated).

Blackstart Capability Plan — a documented procedure for a generating unit or station to go from a shutdown condition to an operating condition delivering electric power without assistance from the electric system. This procedure is only a portion of an overall system restoration plan.

Cascading — the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption, which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.

Database — information organized for reporting, search, and retrieval. (Note: Unless a NERC or Regional database exists, the format and media of the database are at the discretion of the entity.)

Dispersed Load by Substations — substation load information configured to represent a system for power flow and/or system dynamics modeling purposes.

Double-Circuit Line —two three-phase circuits for electric power transmission constructed on a single structure.

Element — any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.

Entities Responsible for the Reliability of the Interconnected Transmission Systems — party or parties (e.g., transmission owners, independent system operators (ISOs), regional transmission organizations (RTOs), or other groups) who are responsible for ensuring that the interconnected transmission systems are being planned and operated within applicable NERC Standards.

Load-Serving Entity — an entity that provides or arranges for serving the electrical demand and energy requirements of its customers.

Planning Horizon — a time period for system planning, typically greater than one year.

Remedial Action Scheme (RAS) — See Special Protection System (SPS).

Region — one of the NERC Regional Electric Reliability Councils.

Special Protection System (SPS) — an automatic protection system (also known as a remedial action scheme) designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS).

Studies — see Analysis.

Additional Terms and Their Definitions as Used in the NERC Planning Standards

Radial Customer — a customer served from an electric system in which the electrical service is through a single transmission element.

Regional Process — a specific method or procedure developed or undertaken by a NERC recognized area to accomplish a specific task or function.

User of the Interconnected Transmission Systems (Bulk Electric System, Electric System) — an entity owning facilities, or receiving or reserving electrical service on the interconnected transmission systems, or with facilities connecting to, or intending to be connected to, the interconnected transmission systems.

Approved by Market Interface Committee: May 3, 2002
Approved by Planning Committee: May 31, 2002
Approved by NERC Board of Trustees: June 14, 2002

Brief Description System performance under normal (no contingency) conditions.

Category Assessments

Section I. System Adequacy and Security
A. Transmission Systems

Standard

S1. The interconnected transmission systems shall be planned, designed, and constructed such that with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the network can deliver generator unit output to meet projected customer demands and projected firm (non-recallable reserved) transmission services, at all demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I (attached).

Transmission system capability and configuration, reactive power resources, protection systems, and control devices shall be adequate to ensure the system performance prescribed in Table I.

Measure

M1. Entities responsible for the reliability of the interconnected transmission systems shall ensure that the system responses for Standard S1 are as defined in Category A (no contingencies) of Table I (attached).

Assessment Requirements

Entities Responsible for the Reliability of Interconnected transmission Systems (ERRIS), as determined by the Region, for example:

1. Transmission owners,
2. Independent system operators (ISOs),
3. Regional transmission organizations (RTOs),

Or other groups responsible for planning the bulk electric system shall assess the performance of their systems in meeting Standard S1.

To be valid *and compliant*, assessments shall:

1. Be made annually,
2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons,
3. Be supported by a current or past study and/or system simulation testing as accepted by the Region showing system performance following Category A of Table 1 (no contingencies) that addresses the plan year being assessed,
4. Address any planned upgrades needed to meet the performance requirements of Category A.

System Simulation Study/Testing Methods

System simulation studies/testing shall (as agreed to by the Region):

1. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

2. Be conducted annually unless changes to system conditions do not warrant such analyses.
3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
4. Have established normal (pre-contingency) operating procedures in place.
5. Have all projected firm transfers modeled.
6. Be performed for selected demand levels over the range of forecast system demands.
7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).
8. Include existing and planned facilities.
9. Include reactive power resources to ensure that adequate reactive resources are available to meet system performance.

Corrective Plan Requirements

When system simulations indicate an inability of the systems to respond as prescribed in this Measurement (M1), responsible entities shall:

1. Provide a written summary of their plans to achieve the required system performance as described above throughout the planning horizon:
   a. Including a schedule for implementation,
   b. Including a discussion of expected required in-service dates of facilities,
   c. Consider lead times necessary to implement plans.
2. For identified system facilities for which sufficient lead times exist, review in subsequent annual assessments for continuing need — detailed implementation plans are not needed.

Reporting Requirements

The documentation of results of these reliability assessments and corrective plans shall annually be provided to the entities' respective NERC Region(s), as required by the Region. Each Region, in turn, shall annually provide a report of its reliability assessments and corrective actions to NERC.

Applicable to

Entities responsible for reliability of interconnected transmission systems.

Items to be Measured

System performance under normal (no contingency) conditions.

Timeframe

Annually

Levels of Non-Compliance (If non-compliant at more than one Level, the highest Level applies.)

Level 1 — N/A

Level 2 — A valid assessment and corrective plan for the longer-term planning horizon is not available.

Level 3 — N/A

Level 4 — A valid assessment and corrective plan for the near-term planning horizon is not available.

Compliance Monitoring Responsibility

Regional Reliability Council. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

Brief Description System performance following loss of a single bulk system element.

Category Assessments

Section I. System Adequacy and Security
A. Transmission Systems

Standard

S2. The interconnected transmission systems shall be planned, designed, and constructed such that the network can be operated to supply projected customer demands and projected firm (non-recallable reserved) transmission services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I (attached).

Transmission system capability and configuration, reactive power resources, protection systems, and control devices shall be adequate to ensure the system performance prescribed in Table I.

The transmission systems also shall be capable of accommodating planned bulk electric equipment outages and continuing to operate within thermal, voltage, and stability limits under the contingency conditions as defined in Category B of Table I (attached).

Measure

M2. Entities responsible for the reliability of the interconnected transmission systems shall ensure that the system responses for Standard S2 contingencies are as defined in Category B (event resulting in the loss of a single element) of Table I (attached).

Assessment Requirements

Entities Responsible for the Reliability of Interconnected transmission Systems (ERRIS), for example:

1. Transmission owners,
2. Independent system operators (ISOs),
3. Regional transmission organizations (RTOs).

Or other groups responsible for planning the bulk electric system shall assess the performance of their systems in meeting Standard S2.

To be valid *and compliant*, assessments shall:

1. Be made annually,
2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons,
3. Be supported by a current or past study and/or system simulation testing as accepted by the Region showing system performance following Category B contingencies that addresses the plan year being assessed,
4. Address any planned upgrades needed to meet the performance requirements of Category B,
5. Consider all contingencies applicable to Category B.

System Simulation Study/Testing Methods

System simulation studies/testing shall:

1. Be performed and evaluated only for those Category B contingencies that would produce the more severe system results or impacts:
   a. The rationale for the contingencies selected for evaluation shall be available as supporting information,
   b. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
3. Be conducted annually unless changes to system conditions do not warrant such analyses.
4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
5. Have all projected firm transfers modeled.
6. Be performed and evaluated for selected demand levels over the range of forecast system demands.
7. Demonstrate that system performance meets Table 1 for Category B contingencies.
8. Include existing and planned facilities.
9. Include reactive power resources to ensure that adequate reactive resources are available to meet system performance.
10. Include the effects of existing and planned protection systems, including any backup or redundant systems.
11. Include the effects of existing and planned control devices.
12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Corrective Plan Requirements

When system simulations indicate an inability of the systems to respond as prescribed in this Measure (M2), responsible entities shall:

1. Provide a written summary of their plans to achieve the required system performance as described above throughout the planning horizon,
   a. Including a schedule for implementation,
   b. Including a discussion of expected required in-service dates of facilities,
   c. Consider lead times necessary to implement plans.
2. For identified system facilities for which sufficient lead times exist, review in subsequent annual assessments for continuing need — detailed implementation plans are not needed.

Reporting Requirements

The documentation of results of these reliability assessments and corrective plans shall annually be provided to the entities' respective NERC Region(s), as required by the Region. Each Region, in turn, shall annually provide a report of its reliability assessments and corrective actions to NERC.

Applicable to

Entities responsible for reliability of interconnected transmission systems.

Items to be Measured

Assessments supported by simulated system performance following loss of a single bulk system element.

Timeframe

Annually

Levels of Non-Compliance (If non-compliant at more than one Level, the highest Level applies.)

Level 1 — N/A

Level 2 — A valid assessment and corrective plan, as defined above, for the longer-term planning horizon is not available.

Level 3 — N/A

Level 4 — A valid assessment and corrective plan, as defined above, for the near-term planning horizon is not available.

Compliance Monitoring Responsibility

Regional Reliability Council. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Brief Description System performance following loss of two or more bulk system elements.

Category Assessments

Section I. System Adequacy and Security
A. Transmission Systems

Standard

S3. The interconnected transmission systems shall be planned, designed, and constructed such that the network can be operated to supply projected customer demands and projected firm (non-recallable reserved) transmission services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer demand, the planned removal of generators, or the curtailment of firm (non-recallable reserved) power transfers maybe necessary to meet this standard.

Transmission system capability and configuration, reactive power resources, protection systems, and control devices shall be adequate to ensure the system performance prescribed in Table I.

The transmission systems also shall be capable of accommodating planned bulk electric equipment outages and continuing to operate within thermal, voltage, and stability limits under the contingency conditions as defined in Category C of Table I (attached).

Measure

M3. Entities responsible for the reliability of the interconnected transmission systems shall ensure that the system responses for Standard S3 contingencies are as defined in Category C (event(s) resulting in the loss of two or more (multiple) elements element of Table I (attached).

Assessment Requirements

Entities Responsible for the Reliability of Interconnected transmission Systems (ERRIS), as determined by the Region, for example:

1. Transmission owners,
2. Independent system operators (ISOs),
3. Regional transmission organizations (RTOs).

Or other groups responsible for planning the bulk electric system shall assess the performance of their systems in meeting Standard S3.

To be valid *and compliant*, assessments shall:

1. Be made annually,
2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons,
3. Be supported by a current or past study and/or system simulation testing as accepted by the Region showing system performance following Category C contingencies that addresses the plan year being assessed,
4. Address any planned upgrades needed to meet the performance requirements of Category C,

5. Consider all contingencies applicable to Category C.

System Simulation Study/Testing Methods

System simulation studies/testing shall (as agreed to by the Region):

1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts.
   a. The rationale for the contingencies selected for evaluation shall be available as supporting information,
   b. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
3. Be conducted annually unless changes to system conditions do not warrant such analyses.
4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
5. Have all projected firm transfers modeled.
6. Be performed and evaluated for selected demand levels over the range of forecast system demands.
7. Demonstrate that system performance meets Table 1 for Category C contingencies.
8. Include existing and planned facilities.
9. Include reactive power resources to ensure that adequate reactive resources are available to meet system performance.
10. Include the effects of existing and planned protection systems, including any backup or redundant systems.
11. Include the effects of existing and planned control devices.
12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Corrective Plan Requirements

When system simulations indicate an inability of the systems to respond as prescribed in this Measure (M3), responsible entities shall:

1. Provide a written summary of their plans to achieve the required system performance as described above throughout the planning horizon,
   a. Including a schedule for implementation,
   b. Including a discussion of expected required in-service dates of facilities,
   c. Consider lead times necessary to implement plans.
2. For identified system facilities for which sufficient lead times exist, review in subsequent annual assessments for continuing need — detailed implementation plans are not needed.

Reporting Requirements

The documentation of results of these reliability assessments and corrective plans shall annually be provided to the entities' respective NERC Region(s), as required by the Region. Each Region, in turn, shall annually provide a report of its reliability assessments and corrective actions to NERC.

Applicable to

Entities responsible for reliability of interconnected transmission systems.

Items to be Measured

Assessments supported by simulated system performance following loss of two or more bulk system element.

Timeframe

Annually

Levels of Non-Compliance (If non-compliant at more than one Level, the highest Level applies.)

Level 1 — N/A

Level 2 — A valid assessment and corrective plan, as defined above, for the longer-term planning horizon is not available.

Level 3 — N/A

Level 4 — A valid assessment and corrective plan, as defined above, for the near-term planning horizon is not available.

Compliance Monitoring Responsibility

Regional Reliability Councils

Brief Description System performance following extreme events resulting in the loss of two or more bulk system elements.

Category Assessments

Section I. System Adequacy and Security
A. Transmission Systems

Standard

S4. The interconnected transmission systems shall be evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I (attached).

Measure

M4. Entities responsible for the reliability of the interconnected transmission systems shall assess the risks and system responses for Standard S4 as defined in Category D of Table I (attached).

Assessment Requirements

Entities Responsible for the Reliability of Interconnected transmission Systems (ERRIS), as determined by the Region, for example:

1. Transmission owners,
2. Independent system operators (ISOs),
3. Regional transmission organizations (RTOs),

Or other groups responsible for planning the bulk electric system shall assess the performance of their systems in meeting Standard S4.

To be valid *and compliant*, assessments shall:

1. Be made annually,
2. Be conducted for near-term (years one through five),
3. Be supported by a current or past study and/or system simulation testing as accepted by the Region showing system performance following Category D contingencies that addresses the plan year being assessed,
4. Consider all contingencies applicable to Category D.

System Simulation Study/Testing Methods

System simulation studies/testing shall (as agree to by the Region):

1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts:
   a. The rationale for the contingencies selected for evaluation shall be available as supporting information,
   b. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
3. Be conducted annually unless changes to system conditions do not warrant such analyses.
4. Have all projected firm transfers modeled.
5. Include existing and planned facilities.
6. Include reactive power resources to ensure that adequate reactive resources are available to meet system performance.
7. Include the effects of existing and planned protection systems, including any backup or redundant systems.
8. Include the effects of existing and planned control devices.
9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Corrective Plan Requirements

None required.

Reporting Requirements

The documentation of results of these reliability assessments shall annually be provided to the entities' respective NERC Region(s), as required by the Region.

Applicable to

Entities responsible for reliability of interconnected transmission systems.

Items to be Measured

Assessments of system performance for extreme events (more severe than in I.A.M3) resulting in loss of two or more bulk system elements.

Timeframe

Annually

Levels of Non-Compliance (If non-compliant at more than one Level, the highest Level applies.)

Level 1 — A valid assessment, as defined above, for the near-term planning horizon is not available.

Level 2 — N/A

Level 3 — N/A

Level 4 — N/A

Compliance Monitoring Responsibility

Regional Reliability Councils. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Table I. Transmission Systems Standards — Normal and Contingency Conditions[*]

Category	Contingencies: Initiating Event(s) and Contingency Element(s)	Elements Out of Service	System Limits or Impacts: Thermal Limits	Voltage Limits	System Stable	Loss of Demand or Curtailed Firm Transfers	Cascading[c] Outages
A - No Contingencies	All Facilities in Service	None	Applicable Rating[a] (A/R)	Applicable Rating[a] (A/R)	Yes	No	No
B - Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Single Single Single Single	 A/R A/R A/R A/R	 A/R A/R A/R A/R	 Yes Yes Yes Yes	 No[b] No[b] No[b] No[b]	 No No No No
	Single Pole Block, Normal Clearing[f]: 4. Single Pole (dc) Line	Single	A/R	A/R	Yes	No[b]	No
C - Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[f]: 1. Bus Section 2. Breaker (failure or internal fault)	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled[d] Planned/Controlled[d]	No No
	SLG or 3Ø Fault, with Normal Clearing[f], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[f]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Multiple	A/R	A/R	Yes	Planned/Controlled[d]	No
	Bipolar Block, with Normal Clearing[f]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[f]: 5. Any two circuits of a multiple circuit towerline[g]	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled[d] Planned/Controlled[d]	No No
	SLG Fault, with Delayed Clearing[f] (stuck breaker or protection system failure): 6. Generator 8. Transformer 7. Transmission Circuit 9. Bus Section	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled[d] Planned/Controlled[d]	No No

[*] Any Region may implement standards that are more stringent, but not inconsistent with NERC's industry-wide standards.

D[e] - Extreme event resulting in two or more (multiple) elements removed or cascading out of service	3Ø Fault, with Delayed Clearing[f] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section - 3Ø Fault, with Normal Clearing[f]: 5. Breaker (failure or internal fault) - Other: 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large load or major load center 12. Failure of a fully redundant special protection system (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant special protection system (or remedial action scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from disturbances in another Regional Council.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating (A/R) refers to the applicable normal and emergency facility thermal rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable ratings may include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All ratings must be established consistent with applicable NERC Planning Standards addressing facility ratings.
b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the faulted element or by the affected area, may occur in certain areas without impacting the overall security of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) electric power transfers.
c) Cascading is the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.
d) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.
e) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
f) Normal clearing is when the protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer (CT), and not because of an intentional design delay.
g) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Brief Description Regional and interregional self-assessment reliability reports.

Category Assessment

Section I. System Adequacy and Security
B. Reliability Assessment

Standard

S1. The overall reliability (adequacy and security) of the Regions' interconnected bulk electric systems, both existing and as planned, shall comply with the NERC Planning Standards and each Region's respective Regional planning criteria.

Measure

M1. Each Region shall annually conduct reliability assessments of its respective existing and planned Regional bulk electric system (generation and transmission facilities) for:

1) Current year:
   - winter
   - summer
   - other system conditions as deemed appropriate by the Region
2) Near-term planning horizons (years one through five) detailed assessments shall be conducted.
3) Longer-term planning horizons (years six through ten). Assessment shall focus on the analysis of trends in resources and transmission adequacy, other industry trends and developments, and reliability concerns.
4) Interregional reliability assessments to ensure that the Regional bulk electric systems are planned and developed on a coordinated or joint basis.

Regional and interregional reliability assessments shall demonstrate that the performance of these systems is in compliance with NERC Standard I.A and respective Regional transmission and generation criteria. These assessments shall also identify key reliability issues and the risks and uncertainties affecting adequacy and security.

Regional and interregional seasonal, near-term, and longer-term reliability assessments shall be provided to NERC on an annual basis.

In addition, special reliability assessments shall also be performed as requested by the NERC Planning Committee or Board of Trustees under their specific directions and criteria. Such assessments may include, but are not limited to:

- Security assessments
- Operational assessments
- Evaluations of emergency response preparedness
- Adequacy of fuel supply and hydro conditions
- Reliability impacts of new or proposed environmental rules and regulations
- Reliability impacts of new or proposed legislation that affects, has affected, or has the potential to affect the adequacy of the interconnected bulk electric systems in North

America.

Applicable to

Regional Reliability Councils

Items to be Measured

Annual Regional and interregional assessments of reliability for seasonal, near-term, and longer-term planning horizons, and special assessments as requested by other Regions or NERC.

Timeframe

Annually or as requested by NERC.

Levels of Non-Compliance

Level 1 — Regional, interregional, and/or special reliability assessments were provided as requested, but were incomplete.

Level 2 — N/A

Level 3 — N/A

Level 4 — Regional, interregional, and/or special reliability assessments were not provided.

Compliance Monitoring Responsibility

NERC

Brief Description Data from the Regions needed to assess reliability.

Category Data

Section I. System Adequacy and Security
B. Reliability Assessment

Standard

S1. The overall reliability (adequacy and security) of the Regions' interconnected bulk electric systems, both existing and as planned, shall comply with the NERC Planning Standards and each Region's respective Regional planning criteria.

Measurement

M2. Each Region shall provide, as requested (seasonally, annually, or as otherwise specified) by NERC, system data, including past, existing, and future facility and bulk electric system data, reports, and system performance information, necessary to assess reliability and compliance with the NERC Planning Standards and the respective Regional planning criteria.

The facility and bulk electric system data, reports, and system performance information shall include, but not be limited to, one or more of the following types of information as outlined below:

1. **Electric Demand and Net Energy for Load (actual and projected demands and net energy for load, forecast methodologies, forecast assumptions and uncertainties, and treatment of demand-side management)**

2. **Resource Adequacy and Supporting Information (Regional assessment reports, existing and planned resource data, resource availability and characteristics, and fuel types and requirements)**

3. **Demand-Side Resources and Their Characteristics (program ratings, effects on annual system loads and load shapes, contractual arrangements, and program durations)**

4. **Supply-Side Resources and Their Characteristics (existing and planned generator units, ratings, performance characteristics, fuel types and availability, and real and reactive capabilities)**

5. **Transmission System and Supporting Information (thermal, voltage, and stability limits, contingency analyses, system restoration, system modeling and data requirements, and protection systems)**

6. **System Operations and Supporting Information (extreme weather impacts, interchange transactions, and congestion impacts on the reliability of the interconnected bulk electric systems)**

7. Environmental and Regulatory Issues and Impacts (air and water quality issues, and impacts of existing, new, and proposed regulations and legislation)

Applicable to
Regions.

Items to be Measured
Regional system data, reports, and system performance information.

Timeframe
Seasonally (winter and summer), annually, or as otherwise requested.

Levels of Non-Compliance
Level 1
Requested Regional system data, reports, or system performance information were incomplete.

Level 2
Not applicable.

Level 3
Not applicable.

Level 4
Requested Regional system data, reports, or system performance information were not provided.

Compliance Monitoring Responsibility
NERC.

Reviewer Comments on Compliance Rating

Brief Description Facility connection requirements.

Category Documentation

Section I. System Adequacy and Security
C. Facility Connection Requirements

Standard

S1. Facility connection requirements shall be documented, maintained, and published by voltage class, capacity, and other characteristics that are applicable to generation, transmission, and electricity end-user facilities which are connected to, or being planned to be connected to, the bulk interconnected transmission systems.

Measurement

M1. Transmission providers, in conjunction with transmission owners, shall document, maintain, and publish facility connection requirements for

a. generation facilities,
b. transmission facilities, and
c. end-user facilities

to ensure compliance with NERC Planning Standards and applicable Regional, subregional, power pool, and individual transmission provider/owner planning criteria and facility connection requirements.

Facility connection requirements shall address, but are not limited to, the following items:

1. **Procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems.**
2. **Procedures for notification of new or modified facilities to others (those responsible for the reliability of the interconnected transmission systems) as soon as feasible.**
3. **Voltage level and MW and Mvar capacity or demand at point of connection.**
4. **Breaker duty and surge protection.**
5. **System protection and coordination.**
6. **Metering and telecommunications.**
7. **Grounding and safety issues.**
8. **Insulation and insulation coordination.**
9. **Voltage, reactive power, and power factor control.**
10. **Power quality impacts.**
11. **Equipment ratings.**
12. **Synchronizing of facilities.**
13. **Maintenance coordination.**
14. **Operational issues (abnormal frequency and voltages).**
15. **Inspection requirements for existing or new facilities.**
16. **Communications and procedures during normal and emergency operating conditions.**

Facility connection requirements shall be maintained and updated as required.

Documentation of these requirements shall be available to the users of the transmission systems, the Regions, and NERC on request (five business days).

Applicable to

Transmission providers and owners.

Items to be Measured

Facility connection requirements for generation facilities, transmission facilities, and end-user facilities.

Timeframe

On request (five business days).

Levels of Non-Compliance

Level 1
Facility connection requirements were provided for generation, transmission, and end-user facilities, but the document(s) do not address all of the requirements.

Level 2
Facility connection requirements were not provided for all three categories (generation, transmission, or end-user) of facilities, but the document(s) provided address all of the requirements.

Level 3
Facility connection requirements were not provided for all three categories (generation, transmission, or end-user) of facilities, and the document(s) provided do not address all of the requirements.

Level 4
No document on facility connection requirements was provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description
Coordination of plans for new generation, transmission, and end-user facilities.

Category
Assessment

Section
I. System Adequacy and Security
C. Facility Connection Requirements

Standard
S2. Generation, transmission, and electricity end-user facilities, and their modifications, shall be planned and integrated into the interconnected transmission systems in compliance with NERC Planning Standards, applicable Regional, subregional, power pool, and individual system planning criteria and facility connection requirements.

Measurement
M2. Those entities responsible for the reliability of the interconnected transmission systems and those entities seeking to integrate generation facilities, transmission facilities, and electricity end-user facilities shall coordinate and cooperate on their respective assessments to evaluate the reliability impact of the new facilities and their connections on the interconnected transmission systems and to ensure compliance with NERC Planning Standards and applicable Regional, subregional, power pool, and individual system planning criteria and facility connection requirements.

The entities involved shall present evidence that they have cooperated on the assessment of the reliability impacts of new facilities on the interconnected transmission systems. While these studies may be performed independently, the results shall be jointly evaluated and coordinated by the entities involved. Assessments shall include steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance under Standard I.A.

Documentation of these assessments shall include study assumptions, system performance, alternatives considered, and jointly coordinated recommendations. This documentation shall be retained for three years and shall be provided to the Regions and NERC on request (within 30 days).

Applicable to
- Entities responsible for the reliability of the interconnected transmission systems.
- Entities seeking to integrate generation, transmission, and end-users facilities into the interconnected transmission systems.

Items to be Measured
Assessment of the reliability impacts of new facilities.

Timeframe
On request (within 30 days).

Levels of Non-Compliance

Level 1
Assessments of the impacts of new facilities were provided, but were incomplete in one or more requirements of Measurement M2.

Level 2
Not applicable.

Level 3
Not applicable.

Level 4
Assessments of the impacts of new facilities were not provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

I. System Adequacy and Security
C. Facility Connection Requirements

G1. Inspection requirements for connected facilities or new facilities to be connected should be included in the facility connection requirements documentation.

G2. Notification of new facilities to be connected, or modifications of existing facilities already connected to the interconnected transmission systems should be provided to those responsible for the reliability of the interconnected transmission systems as soon as feasible to ensure that a review of the reliability impact of the facilities and their connections can be performed and that the facilities are placed in service in a timely manner.

G3. Use of common data and modeling techniques is encouraged.

Brief Description Adequate voltage resources to meet future customer demands.

Section I. System Adequacy and Security
D. Voltage Support and Reactive Power

Standard

S1. Reactive power resources, with a balance between static and dynamic characteristics, shall be planned and distributed throughout the interconnected transmission systems to ensure system performance as defined in Categories A, B, and C of Table I in the I.A. Standards on Transmission Systems.

Measurement

M1. Entities responsible for the reliability of the interconnected transmission systems shall conduct assessments (at least every five years or as required by changes in system conditions) to ensure reactive power resources are available to meet projected customer demands, firm (non-recallable) electric power transfers, and the system performance requirements as defined in Categories A, B, and C of Table I of the I.A. Standards on Transmission Systems. Documentation of these assessments shall be provided to the Regions and NERC on request.

Applicable to

Entities responsible for the reliability of the interconnected transmission systems.

Items to be Measured

Assessment of reactive power resources.

Timeframe

Every five years or as required by system conditions.

Full (100%) Compliance Requirements

The entities shall assess reactive power resources to ensure that adequate reactive resources are available to meet future system performance requirements. These assessment shall demonstrate that system performance is consistent with Categories A, B, and C of Table I of Standard I.A. Additionally, the assessments should address how known changes in system conditions may affect system reliability. These assessments shall be conducted every five years or as required by system conditions. The current assessment results shall be provided to the Regions and NERC on request (within 30 days).

Levels of Non-Compliance

Level 1
Assessments of reactive power resources were provided on schedule, but were incomplete in one or more areas.

Level 2
Assessments of reactive power resources were not provided on schedule, but were complete when submitted.

Level 3
Assessments of reactive power resources were not provided on schedule, and were incomplete in one or more areas when submitted.

Level 4
Assessments of reactive power resources were not provided.

Compliance Monitoring Responsibilities

Regions.

Reviewer Comments on Compliance Rating

Brief Description
Coordinate and optimize the use of generator reactive capability.

Section
I. System Adequacy and Security
D. Voltage Support and Reactive Power

Standard
S1. Reactive power resources, with a balance between static and dynamic characteristics, shall be planned and distributed throughout the interconnected transmission systems to ensure system performance as defined in Categories A, B, and C of Table I in the I.A. Standards on Transmission Systems.

Measurement
M2. Generation owners and transmission providers shall work jointly to optimize the use of generator reactive power capability. These joint efforts shall include:

- **a. Coordination of generator step-up transformer impedance and tap specifications and settings,**
- **b. Calculation of underexcited limits based on machine thermal and stability considerations, and**
- **c. Ensuring that the full range of generator reactive power capability is available for applicable normal and emergency network voltage ranges.**

Applicable to
Generation owners and transmission providers.

Items to be Measured
Generator reactive power capability.

Timeframe
Every five years or as required by changes in generator equipment or system conditions.

Full (100%) Compliance Requirements
Transmission providers and generator owners shall coordinate on optimizing the amount of generator reactive power capability available for use by the transmission network. These efforts should address items such as generator step-up transformers impedance, transformer tap specifications and settings, as well as the calculation of underexcited limits, and other generator thermal and stability considerations.

Transmission providers should generally perform an initial coordination assessment when all required data has been received from the generator owners. Follow-on coordination assessments should be performed at least every five years or when warranted by changes in generation equipment or system conditions. The current assessment results shall be provided to the Regions and NERC on request (within 30 days).

Levels of Non-Compliance

Level 1
Assessments for the optimum use of generator reactive capability were provided on schedule, but were incomplete in one or more areas.

Level 2
Assessments for the optimum use of generator reactive capability were not provided on schedule, but were complete when submitted.

Level 3
Assessments for the optimum use of generator reactive capability were not provided on schedule, and were incomplete in one or more areas when submitted.

Level 4
Assessments for the optimum use of generator reactive capability were not provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

I. System Adequacy and Security
D. Voltage Support and Reactive Power

G1. Transmission owners should plan and design their reactive power facilities so as to ensure adequate reactive power reserves in the form of dynamic reserves at synchronous generators, synchronous condensers, and static var compensators (SVCs and STATCOMs) in anticipation of system disturbances. For example, fixed and mechanically-switched shunt compensation should be used to the extent practical so as to ensure reactive power dynamic reserves at generators and SVCs to minimize the impact of system disturbances.

G2. Distribution entities and customers connected directly to the transmission systems should plan and design their systems to operate at close to unity power factor to minimize the reactive power burden on the transmission systems.

G3. At continuous rated power output, new synchronous generators should have an overexcited power factor capability, measured at the generator terminals, of 0.9 or less and an underexcited power factor capability of 0.95 or less.

If a synchronous generator does not meet this requirement, the generation owner should make alternate arrangements for supplying an equivalent dynamic reactive power capability to meet the area's reactive power requirements.

G4. Reactive power compensation should be close to the area of high reactive power consumption or production.

G5. A balance between fixed compensation, mechanically-switched compensation, and continuously-controlled equipment should be planned.

G6. Voltage support and voltage collapse studies should conform to Regional guidelines.

G7. Power flow simulation of contingencies, including P-V and V-Q curve analyses, should be used and verified by dynamic simulation when steady-state analyses indicate possible insufficient voltage stability margins.

G8. Consideration should be given to generator shaft clutches or hydro water depression capability to allow generators to operate as synchronous condensers.

Brief Description Documentation and content of each Regional TTC and ATC methodology.

Section I. System Adequacy and Security
E. Transfer Capability
1. Total and Available Transfer Capabilities

Standards

S1. Each Region shall develop a methodology for calculating Total Transfer Capability (TTC) and Available Transfer Capability (ATC) that shall comply with the above NERC definitions for TTC and ATC, the NERC Planning Standards, and applicable Regional criteria.

Each Regional TTC and ATC methodology and the resulting TTC and ATC values shall be available to transmission users in the electricity market.

Measurement

M1. Each Region, in conjunction with its members, shall develop and document a Regional TTC and ATC methodology. Certain systems that are not required to post ATC values are exempt from this Standard.

This Regional methodology shall be available to NERC, the Regions, and the transmission users in the electricity market. (S1)

Each Region's TTC and ATC methodology shall (S1):

- **a) Include a narrative explaining how TTC and ATC values are determined.**
- **b) Account for how the reservations and schedules for firm (non-recallable) and non-firm (recallable) transfers, both within and outside the transmission provider's system, are included.**
- **c) Account for the ultimate points of power injection (sources) and power extraction (sinks) in TTC and ATC calculations.**
- **d) Describe how incomplete or so-called partial path transmission reservations are addressed. (Incomplete or partial path transmission reservations are those for which all transmission reservations necessary to complete the transmission path from ultimate source to ultimate sink are not identifiable due to differing reservation priorities, durations, or that the reservations have not all been made.)**
- **e) Require that TTC and ATC values and posting within the current week be determined at least once per day, that daily TTC and ATC values and postings for day 8 through the first month be determined at least once per week, and that monthly TTC and ATC values and postings for months 2 through 13 be determined at least once per month.**

f) Indicate the treatment and level of customer demands, including interruptible demands.

g) Specify how system conditions, limiting facilities, contingencies, transmission reservations, energy schedules, and other data needed by transmission providers for the calculation of TTC and ATC values are shared and used within the Region and with neighboring interconnected electric systems, including adjacent systems, subregions, and Regions. In addition, specify how this information is to be used to determine TTC and ATC values. If some data is not used, provide an explanation.

h) Describe how the assumptions for and the calculations of TTC and ATC values change over different time (such as hourly, daily, and monthly) horizons.

i) Describe the Region's practice on the netting of transmission reservations for purposes of TTC and ATC determination.

Each Regional TTC and ATC methodology shall address each of the items listed above and shall explain its use in determining TTC and ATC values.

The most recent version of the documentation of each Region's TTC and ATC methodology shall be available on a web site accessible by NERC, the Regions, and the transmission users in the electricity market.

Applicable to

Regions.

Items to be Measured

Development and documentation of each Region's TTC and ATC methodology and the completeness of the content of each Regional TTC and ATC methodology.

Timeframe

Available on a web site accessible by NERC, the Regions, and transmission users.

Levels of Non-Compliance

Level 1

The Region's documented TTC and ATC methodology does not address one or two of the nine requirements for such documentation as listed above under Measurement M1.

Level 2

N/A

Level 3

N/A

Level 4

The Region's documented TTC and ATC methodology does not address three or more of the nine requirements for such documentation as listed above under Measurement M1, or the Region does not have a documented TTC and ATC methodology.

Compliance Monitoring Responsibility

NERC.

Reviewer Comments on Compliance Rating

Brief Description Review of transmission provider TTC and ATC calculations and resulting values for compliance with the Regional TTC and ATC methodology.

Section I. System Adequacy and Security
E. Transfer Capability
1. Total and Available Transfer Capabilities

Standards

S1. Each Region shall develop a methodology for calculating Total Transfer Capability (TTC) and Available Transfer Capability (ATC) that shall comply with the above NERC definitions for TTC and ATC, the NERC Planning Standards, and applicable Regional criteria.

Each Regional TTC and ATC methodology and the resulting TTC and ATC values shall be available to transmission users in the electricity market.

Measurement

M3. Each Region, in conjunction with its members, shall develop and implement a procedure to review periodically (at least annually) and ensure that the TTC and ATC calculations and resulting values of member transmission providers comply with the Regional TTC and ATC methodology, the NERC Planning Standards, and applicable Regional criteria. Documentation of the results of the most current Regional reviews shall be provided to NERC on request (within 30 days). (S1)

Applicable to

Regions.

Items to be Measured

Transmission provider TTC and ATC calculations and resulting values for compliance with the Regional TTC and ATC methodology.

Timeframe

Procedure on request (within 30 days).
Documentation of results of Regional reviews on request (within 30 days).

Levels of Non-Compliance

Level 1
N/A.

Level 2
The Region did not perform a review of all transmission providers within its Region for consistency with the Regional TTC and ATC methodology, as documented per Measurement I.E.1. S1, M1, on an annual basis.

Level 3
N/A.

Level 4
The Region does not have a procedure for performing a TTC and ATC methodology consistency review of all transmission providers within its Region, or has not performed any such reviews on an annual basis.

Compliance Monitoring Responsibility

NERC.

Reviewer Comments on Compliance Rating

Brief Description Regional procedure for input on TTC and ATC methodologies and values.

Section
I. System Adequacy and Security
E. Transfer Capability
1. Total and Available Transfer Capabilities

Standards

S1. Each Region shall develop a methodology for calculating Total Transfer Capability (TTC) and Available Transfer Capability (ATC) that shall comply with the above NERC definitions for TTC and ATC, the NERC Planning Standards, and applicable Regional criteria.

Each Regional TTC and ATC methodology and the resulting TTC and ATC values shall be available to transmission users in the electricity market.

Measurement

M4. Each Region, in conjunction with its members, shall develop and document a procedure on how transmission users can input their concerns or questions regarding the TTC and ATC methodology and values of the transmission provider(s), and how these concerns or questions will be addressed. Documentation of the procedure shall be available on a web site accessible by the Regions, NERC, and the transmission users in the electricity market. (S1)

Each Region's procedure shall specify (S1):

- **a) The name, telephone number and email address of a contact person to whom concerns are to be addressed.**
- **b) The amount of time it will take for a response.**
- **c) The manner in which the response will be communicated (e.g., email, letter, telephone, etc.)**
- **d) What recourse a customer has if the response is deemed unsatisfactory.**

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Applicable to
Regions.

Items to be Measured
Regional procedure for receiving and addressing transmission user concerns on the TTC and ATC methodology and TTC and ATC values of member transmission providers.

Timeframe
Procedure available on a web site accessible by the Regions, NERC, and transmission users.

Levels of Non-Compliance

Level 1
N/A.

Level 2
The Region does not have a procedure available on an accessible web site, or the procedure does not provide the information necessary to complete the submittal of a comment, have it processed by the Region, and have an answer provided as indicated in the procedure.

Level 3
N/A.

Level 4
The Region has no procedure available.

Compliance Monitoring Responsibility
NERC.

Reviewer Comments on Compliance Rating

I. System Adequacy and Security
E. Transfer Capability
1. Total and Available Transfer Capabilities

G.1 The Regional responses to transmission user concerns or questions regarding the ATC and TTC methodology and values of the transmission provider(s) should be made publicly available, possibly on a web site, for consistency and to avoid duplicative customer questions.

Brief Description Documentation and content of each Regional Capacity Benefit Margin methodology.

Section
I. System Adequacy and Security
E. Transfer Capability
2. Transfer Capability Margins

Standards

S1. Each Region shall develop a methodology for calculating Capacity Benefit Margin (CBM) that shall comply with the above NERC definition for CBM and applicable Regional criteria.

Each Regional CBM methodology and the resulting CBM values shall be available to transmission users in the electricity market.

Measurement

M1. Each Region, in conjunction with its members, shall develop and document a Regional CBM methodology. This Regional methodology shall be available to NERC, the Regions, and the transmission users in the electricity market. (S1)

Each Region's CBM methodology shall (S1):

a) Specify that the method used by each Regional member to determine its generation reliability requirements as the basis for CBM shall be consistent with its generation planning criteria.
b) Specify the frequency of calculation of the generation reliability requirement and associated CBM values.
c) Require that generation unit outages considered in a transmission provider's CBM calculation be restricted to those units within the transmission provider's system.
d) Require that CBM be preserved only on the transmission provider's system where the load-serving entity's load is located (i.e., CBM is an import quantity only).
e) Describe the inclusion or exclusion rationale for generation resources of each LSE including those generation resources not directly connected to the transmission provider's system but serving LSE loads connected to the transmission provider's system.
f) Describe the inclusion or exclusion rationale for generation connected to the transmission provider's system but not obligated to serve native/network load connected to the transmission provider's system.
g) Describe the formal process and rationale for the Region to grant any variances to individual transmission providers from the Regional CBM methodology.

h) **Specify the relationship of CBM to the generation reliability requirement and the allocation of the CBM values to the appropriate transmission facilities. The sum of the CBM values allocated to all interfaces shall not exceed that portion of the generation reliability requirement that is to be provided by outside resources.**

i) **Describe the inclusion or exclusion rationale for the loads of each LSE, including interruptible demands and buy-through contracts (type of service contract that offers the customer the option to be interrupted or to accept a higher rate for service under certain conditions).**

j) **Describe the inclusion or exclusion rationale for generation reserve sharing arrangements in the CBM values.**

Each Regional CBM methodology shall address each of the items listed above and shall explain its use, if any, in determining CBM values. Other items that are Regional specific or that are considered in each respective Regional methodology shall also be explained along with their use in determining CBM values.

The most recent version of the documentation of each Region's CBM methodology shall be available on a web site accessible by NERC, the Regions, and the transmission users in the electricity market.

Applicable to

Regions.

Items to be Measured

Development and documentation of each Region's Capability Benefit Margin methodology and the completeness of the content of each Regional CBM methodology.

Timeframe

Available on a web site accessible by NERC, the Regions, and transmission users.

Levels of Non-Compliance

Level 1

The Region's documented CBM methodology does not address one or two of the ten requirements for such documentation as listed above under Measurement M1.

Level 2

N/A.

Level 3

N/A.

Level 4
The Region's documented CBM methodology does not address three or more of the ten requirements for such documentation as listed above under Measurement M1, or the Region does not have a documented CBM methodology.

Compliance Monitoring Responsibility

NERC.

Reviewer Comments on Compliance Rating

Brief Description Procedure for verifying Capacity Benefit Margin values.

Section
I. System Adequacy and Security
E. Transfer Capability
2. Transfer Capability Margins

Standard

S1. Each Region shall develop a methodology for calculating Capacity Benefit Margin (CBM) that shall comply with the above NERC definition for CBM and applicable Regional criteria.

Each Regional CBM methodology and the resulting CBM values shall be available to transmission users in the electricity market.

Measurement

M3. Each Region, in conjunction with its members, shall develop and implement a procedure to review the CBM calculations and values of member transmission providers to ensure that they comply with the Regional CBM methodology and are periodically updated (at least annually) and available to transmission users. Documentation of the results of the most current Regional reviews shall be provided to NERC on request (within 30 days). (S1)

This Regional procedure shall:

a) Indicate the frequency under which the verification review shall be implemented.
b) Require review of the process by which CBM values are updated, and their frequency of update, to ensure that the most current CBM values are available to transmission users.
c) Require review of the consistency of the transmission provider's CBM components with its published planning criteria. A CBM value is considered consistent with published planning criteria if the same components that comprise CBM are also addressed in the planning criteria. The methodology used to determine and apply CBM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumptions explained. It is recognized that ATC determinations are often time constrained and thus will not permit the use of the same mechanics employed in the more rigorous planning process.
d) Require CBM values to be periodically updated (at least annually) and available to the Regions, NERC, and transmission users in the electricity markets.

The documentation of the Regional CBM procedure shall be available to NERC on request (within 30 days). Documentation of the results of the most current implementation of the procedure shall be available to NERC on request (within 30 days).

Applicable to

Regions.

Items to be Measured

Regional procedure and its implementation for verifying member transmission provider CBM values.

Timeframe

Procedure on request (within 30 days).
Results of procedure implementation on request (within 30 days).

Levels of Non-Compliance

Level 1
N/A.

Level 2
The Region did not perform a review of all transmission providers within its Region for consistency with the Regional CBM methodology, as documented per Measurement I.E.2 S1, M1, on an annual basis.

Level 3
N/A.

Level 4
The Region does not have a procedure for performing a CBM methodology consistency review of all transmission providers within its Region, or has not performed any such review on an annual basis.

Compliance Monitoring Responsibility

NERC.

Brief Description Procedures for the use of Capacity Benefit Margin values.

Section
I. System Adequacy and Security
E. Transfer Capability
2. Transfer Capability Margins

Standard

S1. Each Region shall develop a methodology for calculating Capacity Benefit Margin (CBM) that shall comply with the above NERC definition for CBM and applicable Regional criteria.

Each Regional CBM methodology and the resulting CBM values shall be available to transmission users in the electricity market.

Measurement

M4. Each transmission provider shall document and make available its procedures on the use of CBM (scheduling of energy against a CBM preservation) to the Regions, NERC, and the transmission users in the electricity market.

These procedures shall (S1):

a) Require that CBM is to be used only after the following steps have been taken (as time permits): all non-firm sales have been terminated, direct-control load management has been implemented, and customer interruptible demands have been interrupted. CBM may be used to reestablish operating reserves.
b) Require that CBM shall only be used if the LSE calling for its use is experiencing a generation deficiency and its transmission provider is also experiencing transmission constraints relative to imports of energy on its transmission system.
c) Describe the conditions under which CBM may be available as non-firm transmission service. (S1)

The transmission providers shall make their CBM use procedures available on a web site accessible by the Regions, NERC, and the transmission users in the electricity market.

Applicable to

Transmission providers.

Items to be Measured

Documentation of CBM use procedures.

Timeframe

Available on a web site accessible by the Regions, NERC, and transmission users.

Levels of Non-Compliance

Level 1
The transmission provider's CBM use procedure is available and addresses only two of the three requirements for such documentation as listed above under Measurement M4.

Level 2
N/A.

Level 3
N/A.

Level 4
The transmission provider's CBM use procedure addresses one or none of the three requirements as listed above under Measurement M4, or is not available.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description Documentation of the use of Capacity Benefit Margin.

Section
I. System Adequacy and Security
E. Transfer Capability
2. Transfer Capability Margins

Standard

S1. Each Region shall develop a methodology for calculating Capacity Benefit Margin (CBM) that shall comply with the above NERC definition for CBM and applicable Regional criteria.

Each Regional CBM methodology and the resulting CBM values shall be available to transmission users in the electricity market.

Measurement

M5. Each transmission provider that uses CBM shall report to the Regions, NERC, and the transmission users the use of CBM by the load-serving entities' loads on its system, except for CBM sales as non-firm transmission service. This disclosure may be after the fact. (S1)

Within 15 days after the use of CBM for emergency purposes, a transmission provider shall make available the 1) circumstances, 2) duration, and 3) amount of CBM used. This information shall be available on a web site accessible by the Regions, NERC, and the transmission users in the electricity market.

The use of CBM also shall be consistent with the transmission provider's CBM use procedures.

The scheduling of energy against a CBM preservation as non-firm transmission service need not be disclosed to comply with this Standard.

Applicable to

Transmission providers.

Items to be Measured

After the fact disclosure that energy was scheduled against a CBM preservation (for purposes other than non-firm transmission sales).

Timeframe

Within 15 days of the use of CBM (excluding non-firm sales).

Levels of Non-Compliance

Level 1
N/A.

Level 2
Information pertaining to the use of CBM during an energy emergency was provided, but was not made available on a web site accessible by the Regions, NERC, and transmission users in the electricity market, or meets only two of the three requirements as listed above under Measurement M5.

Level 3
N/A.

Level 4
After the use of CBM (excluding non-firm sales), information pertaining to the use of CBM was provided but meets one or none of the three requirements as listed above under Measurement M5, or no information was provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description Documentation and content of each Regional Transmission Reliability Margin methodology.

Section
I. System Adequacy and Security
E. Transfer Capability
2. Transfer Capability Margins

Standard

S2. Each Region shall develop a methodology for calculating Transmission Reliability Margin (TRM) that shall comply with the above NERC definition for TRM and applicable Regional criteria.

Each Regional TRM methodology and the resulting TRM values shall be available to transmission users in the electricity market.

Measurement

M6. Each Region, in conjunction with its members, shall develop and document a Regional TRM methodology. This Regional methodology shall be available to NERC, the Regions, and the transmission users in the electricity market. (S2)

Each Region's TRM methodology shall (S2):

a) Specify the update frequency of TRM calculations.
b) Specify how TRM values are incorporated into ATC calculations.
c) Specify the uncertainties accounted for in TRM and the methods used to determine their impacts on the TRM values.

The following components of uncertainty, if applied, shall be accounted for solely in TRM and not CBM: aggregate load forecast error (not included in determining generation reliability requirements), load distribution error, variations in facility loadings due to balancing of generation within a control area, forecast uncertainty in transmission system topology, allowances for parallel path (loop flow) impacts, allowances for simultaneous path interactions, variations in generation dispatch, and short-term operator response (operating reserve actions not exceeding a 59-minute window).

Any additional components of uncertainty shall benefit the interconnected transmission systems, as a whole, before they shall be permitted to be included in TRM calculations.

d) Describe the conditions, if any, under which TRM may be available to the market as non-firm transmission service.
e) Describe the formal process for the Region to grant any variances to individual transmission providers from the Regional TRM methodology.

Each Regional TRM methodology shall address each of the items above and shall explain its use, if any, in determining TRM values. Other items that are Regional specific or that are considered in each respective Regional methodology shall also be explained along with their use in determining TRM values.

The most recent version of the documentation of each Region's TRM methodology shall be available on a web site accessible by NERC, the Regions, and the transmission users in the electricity market.

Applicable to
Regions.

Items to be Measured
Development and documentation of each Region's Transmission Reliability Margin methodology and the completeness of the content of each Regional TRM methodology.

Timeframe
Available on a web site accessible by NERC, the Regions, and transmission users.

Levels of Non-Compliance

Level 1
The Region's document TRM methodology does not address one of the five requirements for each documentation as listed above under Measurement M6.

Level 2
N/A.

Level 3
N/A.

Level 4
The Region's documented TRM methodology does not address two or more of the five requirements for such documentation as listed above under Measurement M6, or the Region does not have a documented TRM methodology.

Compliance Monitoring Responsibility
NERC.

Brief Description Procedure for verifying Transmission Reliability Margin values.

Section
I. System Adequacy and Security
E. Transfer Capability
2. Transfer Capability Margins

Standard

S2. Each Region shall develop a methodology for calculating Transmission Reliability Margin (TRM) that shall comply with the above NERC definition for TRM and applicable Regional criteria.

Each Regional TRM methodology and the resulting TRM values shall be available to transmission users in the electricity market.

Measurement

M8. Each Region, in conjunction with its members, shall develop and implement a procedure to review the TRM calculations and values of member transmission providers to ensure that they comply with the Regional TRM methodology and are periodically updated and available to transmission users. Documentation of the results of the most current Regional reviews shall be provided to NERC on request (within 30 days). (S2)

This Regional procedure shall:

a) Indicate the frequency under which the verification review shall be implemented.

b) Require review of the process by which TRM values are updated, and their frequency of update, to ensure that the most current TRM values are available to transmission users.

c) Require review of the consistency of the transmission provider's TRM components with its published planning criteria. A TRM value is considered consistent with published planning criteria if the same components that comprise TRM are also addressed in the planning criteria. The methodology used to determine and apply TRM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumption explained. It is recognized that ATC determinations are often time constrained and thus will not permit the use of the same mechanics employed in the more rigorous planning process.

d) Require TRM values to be periodically updated (at least prior to each season ¾ winter, spring, summer, and fall), as necessary, and made available to the Regions, NERC, and transmission users in the electricity market.

The documentation of the Regional TRM procedure shall be available to NERC on request (within 30 days). Documentation of the results of the most current implementation of the procedure shall be available to NERC on request (within 30 days).

Applicable to

Regions.

Items to be Measured

Regional procedure and its implementation for verifying member transmission provider TRM values.

Timeframe

Procedure on request (within 30 days).
Results of procedure implementation on request (within 30 days).

Levels of Non-Compliance

Level 1
N/A.

Level 2
The Region did not perform a review of all transmission providers within its Region for consistency with the Regional TRM methodology, as documented per Measurement I.E.2 S2, M8, on an annual basis.

Level 3
N/A.

Level 4
The Region does not have a procedure for performing a TRM methodology consistency review of all transmission providers in its Region, or has not performed any such reviews on an annual basis.

Compliance Monitoring Responsibility

NERC.

Brief Description Define and document disturbance monitoring equipment requirements.

Category Documentation and Implementation

Section I. System Adequacy and Security
F. Disturbance Monitoring

Standard

S1. Requirements shall be established on a Regional basis for the installation of disturbance monitoring equipment (e.g., sequence-of-event, fault recording, and dynamic disturbance recording equipment) that is necessary to ensure data is available to determine system performance and the causes of system disturbances.

Measure

M1. Each Region shall develop comprehensive requirements for the installation of disturbance monitoring equipment to ensure data is available to determine system performance and the causes of system disturbances.

The comprehensive Regional requirements shall include the following items:

Technical requirements:

1. Type of data recording capability (e.g., sequence-of-event, fault recording, dynamic disturbance recording).
2. Equipment characteristics including but not limited to:
   - recording duration requirements
   - time synchronization requirements
   - data format requirements
   - event triggering requirements
3. Monitoring, recording, and reporting capabilities of the equipment
   - voltage
   - current
   - frequency
   - MW and/or Mvar, as appropriate
4. Data retention capabilities
   (e.g., length of time data is to be available for retrieval)

Monitoring equipment location requirements:

5. Regional coverage requirements (e.g., by voltage, geographic area, electric area/subarea)
6. Installation requirements:
   - substations
   - transmission lines
   - generators

Testing and maintenance requirements:

7. Responsibility for maintenance and/or testing

Documentation requirements:

8. Requirements for periodic (at least every five years) updating, review, and approval of the Regional requirements

The Regional requirements shall be provided to other Regions and NERC on request (30 days).

Applicable to

Regions

Items to be Measured

Regional requirements for the installation of disturbance monitoring equipment.

Timeframe

On request by NERC (30 days).

Levels of Non-Compliance

Level 1 — The Region's disturbance monitoring requirements do not address one of the eight requirements for the installation of disturbance monitoring equipment as listed above under Measure M1.

Level 2 — The Region's disturbance monitoring requirements do not address two of the eight requirements for the installation of disturbance monitoring equipment as listed above under Measure M1.

Level 3 — The Region's disturbance monitoring requirements do not address three of the eight requirements for the installation of disturbance monitoring equipment as listed above under Measure M1.

Level 4 — The Region's disturbance monitoring requirements were not provided or do not address four or more of the eight requirements for the installation of disturbance monitoring equipment as listed above under Measure M1.

Compliance Monitoring Responsibility

NERC

Brief Description Disturbance monitoring equipment list.

Category Data

Section I. System Adequacy and Security
F. Disturbance Monitoring

Standard

S1. Requirements for the installation of disturbance monitoring equipment (e.g., sequence-of-event, fault recording, and dynamic disturbance recording equipment) that is necessary to ensure data is available to determine system performance and the causes of system disturbances shall be established on a Regional basis.

Measurement

M2. Regional members, generation owners, and transmission owners shall install disturbance monitoring equipment to meet the Regional requirements determined in I.F. S1, M1.

The following data on the disturbance monitoring installations shall be maintained:

1. **Type of equipment**
2. **Make and model of equipment**
3. **Installation location**
4. **Monitored facilities (lines, buses, etc.) and associated quantities (MW, Mvar, etc.)**
5. **Operational status**
6. **Date last tested**

Current data on the disturbance monitoring equipment installations shall be provided to the Regions and NERC on request (30 business days).

Applicable to

Regional members, transmission owners, generation owners.

Items to be Measured

Disturbance monitoring equipment installations and operational status.

Timeframe

On request (30 business days).

Levels of Non-Compliance

Level 1
Disturbance monitoring equipment is installed at all required locations in accordance with the Regional requirements defined in I.F. S1, M1, however, the data provided was incomplete and did not meet one of the six requirements listed above in Measurement M2.

Level 2
Disturbance monitoring equipment is installed at all required locations in accordance with the Regional requirements defined in I.F. S1, M1, however, the data provided was incomplete and did not meet two of the six requirements listed above in Measurement M2.

Level 3
Not applicable.

Level 4
Disturbance monitoring equipment is not installed at all required locations in accordance with the Regional requirements defined in I.F. S1, M1, or data for the disturbance monitoring equipment installations was not provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description Disturbance monitoring data reporting requirements.

Category Documentation

Section I. System Adequacy and Security
F. Disturbance Monitoring

Standard

S2. Requirements for providing disturbance monitoring data for the purpose of developing, maintaining, and updating transmission system models shall be established on a Regional basis.

Measurement

M3. Each Region shall establish requirements for entities to provide disturbance monitoring data to ensure that data is available to determine system performance and the causes of system disturbances.

Each Region's disturbance monitoring data reporting requirements shall include:

1. **Definition of "disturbance"**
2. **General requirements for data format**
3. **Data content requirements and guidelines**
4. **Timetable for response to data request**
5. **Requirements for the storage and retention of the disturbance data**
6. **The process for the periodic review and approval of the Region's disturbance monitoring data reporting requirements**

Documentation of Regional data reporting requirements shall be provided to other Regions and NERC on request (five business days).

Applicable to

Regions.

Items to be Measured

Regional disturbance monitoring data reporting requirements.

Timeframe

On request (five business days).

Levels of Non-Compliance

Level 1
The Regional requirements for providing disturbance monitoring data do not address one of the six areas as listed above in Measurement M3.

Level 2
The Regional requirements for providing disturbance monitoring data do not address two of the six areas as listed above in Measurement M3.

Level 3
Not applicable.

Level 4
The Regional requirements for providing disturbance monitoring data were not provided, or the Regional requirements for providing disturbance monitoring data do not address three or more of the six areas as listed above in Measurement M3.

Compliance Monitoring Responsibility

NERC.

Reviewer Comments on Compliance Rating

Brief Description Disturbance data.

Category Data

Section I. System Adequacy and Security
F. Disturbance Monitoring

Standard

S2. **Requirements for providing disturbance monitoring data for the purpose of developing, maintaining, and updating transmission system models shall be established on a Regional basis.**

Measurement

M4. **Regional members, generation owners, and transmission owners shall provide system disturbance data to the Regions in compliance with the respective Regional requirements identified in Measurement I.F. S2, M3.**

The current system disturbance data shall be provided to NERC on request (30 business days).

Applicable to

Regional members, generation owners, transmission owners.

Items to be Measured

System disturbance data.

Timeframe

As specified in the Regional requirements (Standard I.F. S2, M3).
Current data on request (30 business days).

Levels of Non-Compliance

Level 1
Disturbance data from the disturbance monitoring equipment was provided, however, the data was incomplete and did not meet all of the requirements of the respective Regional requirements.

Level 2
Not applicable.

Level 3
Not applicable.

Level 4
Disturbance data from the disturbance monitoring equipment was not provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description Fault and disturbance data.

Section I. System Adequacy and Security
F. Disturbance Monitoring

Standard

S1. **Requirements for the installation of disturbance monitoring equipment (e.g., sequence-of-event, fault recording, and dynamic disturbance recording equipment) that is necessary to ensure data is available to determine system performance and the causes of system disturbances shall be established on a Regional basis.**

S2. **Requirements for providing disturbance monitoring data for the purpose of developing, maintaining, and updating transmission system models shall be established on a Regional basis.**

Measurement

M5. **Regional members shall provide to their respective Regions system fault and disturbance data in compliance with Regional requirements. Each Region shall maintain and annually update a database of the recorded information.**

Applicable to

A. Regional members.
B. Regions.

Items to be Measured

A. System fault and disturbance data.
B. Maintain system fault and disturbance database.

Timeframe

A. Annually (as scheduled by the Region).
B. Annually (as scheduled by the Region).

Full (100%) Compliance Requirements

A. Regional members shall provide fault and disturbance data to the Regions according to the requirements identified in Standard I.F. S2, M4.
B. Regions shall maintain a disturbance monitoring database and update it annually according to the requirements in Standards I.F. S1, M1 and I.F. S2, M4. The current database shall be provided to NERC on request (within 30 days).

Levels of Non-Compliance

A. **Level 1**
Fault and disturbance data from the Regional members was provided on schedule, but was incomplete in one or more areas.

Level 2
Fault and disturbance data from the Regional members was not provided on schedule, but was complete when submitted.

Level 3
Fault and disturbance data from the Regional members was not provided on schedule, and was incomplete in one or more areas when submitted.

Level 4
Fault and disturbance data from the Regional members was not provided.

B. **Level 1**
The Regional disturbance monitoring database was provided on schedule, but was incomplete in one or more areas.

Level 2
The Regional disturbance monitoring database was not provided on schedule, but was complete when submitted.

Level 3
The Regional disturbance monitoring database was not provided on schedule, and was incomplete in one or more areas when submitted.

Level 4
The Regional disturbance monitoring database was not provided.

Compliance Monitoring Responsibility

A. Regions.
B. NERC.

Reviewer Comments on Compliance Rating

Brief Description Use of disturbance data to develop and maintain models.

Section I. System Adequacy and Security
F. Disturbance Monitoring

Standard

S2. **Requirements for providing disturbance monitoring data for the purpose of developing, maintaining, and updating transmission system models shall be established on a Regional basis.**

Measurement

M6. **Regional members shall use recorded data from disturbance monitoring equipment to develop, maintain, and enhance steady-state and dynamic system models and generator performance models.**

Applicable to

Regional members.

Items to be Measured

Use of database in Standard I.F. S1 and S2, M5.

Timeframe

On request (within 30 days).

Full (100%) Compliance Requirements

The information in the Region's database (Standard I.F. S1 and S2, M5) shall be used to improve steady-state and dynamic system models and generator performance models. Changes incorporated in the models should note how system fault and disturbance data may have been used to effect such changes. This documentation shall be provided to the Regions on request (within 30 days).

Levels of Non-Compliance

Level 1
Documentation of model changes resulting from the Regional database was provided on schedule, but was incomplete in one or more areas.

Level 2
Documentation of model changes resulting from the Regional database was not provided on schedule, but was complete when submitted.

Level 3
Documentation of model changes resulting from the Regional database was not provided on schedule, and was incomplete in one or more areas when submitted.

Level 4
Documentation of model changes resulting from the Regional database was not provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

I. System Adequacy and Security
F. Disturbance Monitoring

G1. Data from transmission system disturbance monitoring equipment should be in a consistent, time synchronized format.

G2. The Regional database should be used to identify locations on the transmission systems where additional disturbance monitoring equipment may be needed.

G3. The monitored data from disturbance monitoring equipment should be used to develop, maintain, validate, and enhance generator performance models and steady-state and dynamic system models.

G4. Each Region should establish and coordinate the requirements for the installation of disturbance monitoring equipment with neighboring Regions.

Brief Description Steady-state data for modeling and simulation of the interconnected transmission systems.

Category Data

Section II. System Modeling Data Requirements
A. System Data

Standard

S1. Electric system data required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained.

Measurement

M1. All the users of the interconnected transmission systems shall provide appropriate equipment characteristics, system data, and existing and future interchange transactions in compliance with the respective Interconnection-wide Regional data requirements and reporting procedures as defined in Standard II.A. S1, M2 for the modeling and simulation of the steady-state behavior of the NERC Interconnections: Eastern, Western, and ERCOT.

This data shall be provided to the Regions, NERC, and those entities responsible for the reliability of the interconnected transmission systems as specified within the applicable reporting procedures (Standard II.A. S1, M2). If no schedule exists, then data shall be provided on request (30 business days).

Applicable to

Users of the interconnected transmission systems.

Items to be Measured

Equipment characteristics, system data, and interchange transactions for steady-state simulation.

Timeframe

As specified within the applicable reporting procedures (Standard II.A. S1, M2). If no schedule exists, then on request (30 business days).

Levels of Non-Compliance

Level 1
Steady-state data was provided, but was incomplete in one of the seven areas identified in Standard II.A. S1, M2.

Level 2
Not applicable.

Level 3
Steady-state data was provided, but was incomplete in two or more of the seven areas identified in Standard II.A. S1, M2.

Level 4
Steady-state data was not provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description Maintenance and distribution of steady-state data requirements and reporting procedures.

Category Documentation

Section II. System Modeling Data Requirements
A. System Data

Standard

S1. Electric system data required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained.

Measurement

M2. The Regions, in coordination with the entities responsible for the reliability of the interconnected transmission systems, shall develop comprehensive steady-state data requirements and reporting procedures needed to model and analyze the steady-state conditions for each of the NERC Interconnections: Eastern, Western, and ERCOT. Within an Interconnection, the Regions shall jointly coordinate on the development of the data requirements and reporting procedures for that Interconnection.

The following list describes the steady-state data that shall be addressed in the Interconnection-wide requirements:

1. **Bus (substation and switching station): name, nominal voltage, electrical demand (load) supplied (consistent with the aggregated and dispersed substation demand data supplied per Standard II.D.), and location.**
2. **Generating Units (including synchronous condensers, pumped storage, etc.): location, minimum and maximum ratings (net real and reactive power), regulated bus and voltage set point, and equipment status.**
3. **AC Transmission Line or Circuit (overhead and underground): nominal voltage, impedance, line charging, normal and emergency ratings (consistent with methodologies defined and ratings supplied per Standard II.C.), equipment status, and metering locations.**
4. **DC Transmission Line (overhead and underground): Line parameters, normal and emergency ratings, control parameters, rectifier data, and inverter data.**
5. **Transformer (voltage and phase-shifting): nominal voltages of windings, impedance, tap ratios (voltage and/or phase angle or tap step size), regulated bus and voltage set point, normal and emergency ratings (consistent with methodologies defined and ratings supplied per Standard II.C.), and equipment status.**
6. **Reactive Compensation (shunt and series capacitors and reactors): nominal ratings, impedance, percent compensation, connection point, and controller device.**
7. **Interchange Transactions: Existing and future interchange transactions and/or assumptions.**

The data requirements and reporting procedures for each of the NERC Interconnections (Eastern, Western, and ERCOT) shall be documented, reviewed (at least every five years), and available to the Regions, NERC, and all users of the interconnected transmission systems on request (five business days).

Applicable to

Regions.

Items to be Measured

Documentation of steady-state data requirements and reporting procedures for each NERC Interconnection.

Timeframe

Data requirements and reporting procedures: on request (five business days).
Periodic review of data requirements and reporting procedures: at least every five years.

Levels of Non-Compliance

Level 1
Data requirements and reporting procedures for steady-state data were provided , but were incomplete in one of the seven areas defined in above Measurement M2.

Level 2
Data requirements and reporting procedures for steady-state data were provided, but were incomplete in two of the seven areas defined in above Measurement M2.

Level 3
Not applicable.

Level 4
Data requirements and reporting procedures for steady-state data were not provided, or the data requirements and reporting procedures provided were incomplete in three or more of the seven areas defined in above Measurement M2.

Compliance Monitoring Responsibility

NERC.

Reviewer Comments on Compliance Rating

Brief Description Dynamics data for modeling and simulation of the interconnected transmission systems.

Category Data

Section II. System Modeling Data Requirements
A. System Data

Standard

S1. Electric system data required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained.

Measurement

M3. All users of the interconnected transmission systems shall provide appropriate equipment characteristics and system data in compliance with the respective Interconnection-wide Regional data requirements and reporting procedures as defined in Standard II.A. S1, M4 for the modeling and simulation of the dynamic behavior of the NERC Interconnections: Eastern, Western, and ERCOT.

This data shall be provided to the Regions, NERC, and those entities responsible for the reliability of the interconnected transmission systems as specified within the applicable reporting procedures (Standard II.A. S1, M4). If no schedule exists, then data shall be provided on request (30 business days).

Applicable to

Users of the interconnected transmission systems.

Items to be Measured

Equipment characteristics and system data for dynamics simulation.

Timeframe

As specified within the applicable reporting procedures (Standard II.A. S1, M4). If no schedule exists, then on request (30 business days).

Levels of Non-Compliance

Level 1
Dynamics data was provided, but was incomplete in one of the four areas identified in Standard II.A. S1, M4.

Level 2
Not applicable.

Level 3
Dynamics data was provided, but was incomplete in two or more of the four areas identified in Standard II.A. S1, M4.

Level 4
Dynamics data was not provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description Maintenance and distribution of dynamics data requirements and reporting procedures.

Category Documentation

Section II. System Modeling Data Requirements
A. System Data

Standard

S1. Electric system data required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained.

Measurement

M4. The Regions, in coordination with the entities responsible for the reliability of the interconnected transmission systems, 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 Regions shall jointly coordinate on the development of the data requirements and reporting procedures for that Interconnection.

The following list describes the dynamics data that shall be addressed in the Interconnection-wide requirements:

1. **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.**

   However, 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.

   The Interconnection-wide requirements shall specify unit size thresholds for permitting: 1.) the use of non-detailed vs. detailed models, 2.) the netting of small generating units with bus load, and 3.) the combining of multiple generating units at one plant.

2. **Device specific dynamics data shall be reported for dynamic devices, including, among others, static var controls (SVC), high voltage direct current systems (HVDC), flexible AC transmission systems (FACTS), and static compensators (STATCOM).**

3. **Dynamics data representing electrical demand (load) characteristics as a function of frequency and voltage.**

4. **Dynamics data shall be consistent with the reported steady-state (power flow) data supplied per Standard II.A. S1, M1.**

The data requirements and reporting procedures for each of the NERC Interconnections (Eastern, Western, and ERCOT) shall be documented, reviewed (at least every five years), and available to the Regions, NERC, and all users of the interconnected systems on request (five business days).

Applicable to
Regions.

Items to be Measured
Documentation of dynamics data requirements and reporting procedures for each NERC Interconnection.

Timeframe
Data requirements and reporting procedures: on request (five business days).
Periodic review of data requirements and reporting procedures: at least every five years.

Levels of Non-Compliance
Level 1
Data requirements and reporting procedures for dynamics data were provided , but were incomplete in one of the four areas defined in above Measurement M4.

Level 2
Not applicable.

Level 3
Not applicable.

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 or more of the four areas defined in above Measurement M4.

Compliance Monitoring Responsibility
NERC.

Reviewer Comments on Compliance Rating

Brief Description Development of steady-state system models.

Category System models (steady-state)

Section II. System Modeling Data Requirements
A. System Data

Standard

S1. Electric system data required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained.

Measure

M5. Each of the NERC Interconnections shall develop and maintain a library of solved (converged) steady-state system models. Models shall be developed for the near- and longer-term planning horizons that are representative of system conditions for projected seasonal peak, minimum, and other appropriate system demand levels. Within the Eastern Interconnection, the Regions shall coordinate and jointly develop the steady-state system models for that Interconnection.

Steady-state system models for each of the NERC Interconnections (Eastern, Western, and ERCOT) shall be developed annually for selected study years as determined by the Interconnection. The most recent solved (converged) steady-state models shall be provided to the Regions and NERC on request (30 days).

Applicable to

Regional Reliability Councils

Items to be Measured

Development of Interconnection steady-state system models.

Timeframe

Development of steady-state system models: annually.
Most recent steady-state system models: 30 days

Levels of Non-Compliance

An assessment of non-compliance will only be considered if a posting date is not met. Violations will not be assessed for Data Sets posted by the scheduled dates.

Level 1 — One of a Region’s cases was either not submitted by the data submission deadlines, or was submitted by the data submission deadline but was not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline.

Level 2 — Two of a Region’s cases were either not submitted by the data submission deadlines, or were submitted by the data submission deadline but were not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).

Level 3 — Three of a Region’s cases were either not submitted by the data submission deadlines, or were submitted by the data submission deadline but were not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).

Level 4 — Four or more of a Region’s cases were either not submitted by the data submission deadlines, or were submitted by the data submission deadline but were not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).

Compliance Monitoring Responsibility

NERC

Brief Description Development of dynamics system models.

Category System models (dynamics)

Section II. System Modeling Data Requirements
A. System Data

Standard

S1. Electric system data required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained.

Measure

M6. Each of the Interconnections shall develop and maintain a library of initialized (with no faults or system disturbances) dynamics system models. Models shall be developed for at least two timeframes (present or near-term model and a future or longer-term model). Additional seasonal and demand level models shall be developed, as necessary, to analyze the dynamic response of each of the NERC Interconnections: Eastern, Western, and ERCOT. These dynamics system models shall be linked to the steady-state system models, as appropriate, of Standard II.A.M5. Within the Eastern Interconnection, the Regions shall coordinate and jointly develop the dynamics system models for that Interconnection.

Dynamics system models for each of the NERC Interconnections (Eastern, Western, and ERCOT) shall be developed annually for selected study years as determined by the Interconnection. The most recent initialized (approximately 25 seconds, no-fault) models shall be provided to the Regions and NERC on request (30 days).

Applicable to

Regional Reliability Councils

Items to be Measured

Development of Interconnection dynamics system models.

Timeframe

Development of dynamics system models: annually.
Most recent dynamics system models: on request (30 days).

Levels of Non-Compliance

An assessment of non-compliance will only be considered if a posting date is not met. Violations will not be assessed for Data Sets posted by the scheduled dates.

Level 1 — One of a Region's cases was either not submitted by the data submission deadlines, or was submitted by the data submission deadline but was not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline.

Level 2 — Two of a Region's cases were either not submitted by the data submission deadlines, or were submitted by the data submission deadline but were not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).

Level 3 — Three of a Region's cases were either not submitted by the data submission deadlines, or were submitted by the data submission deadline but were not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).

Level 4 — Four or more of a Region's cases were either not submitted by the data submission deadlines, or were submitted by the data submission deadline but were not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).

Compliance Monitoring Responsibility

NERC

II. System Modeling Data Requirements
A. System Data

G1. Any changes to interconnection tie line data should be agreed upon by all involved facility owners.

G2. The in-service date should be the year and season that a facility will be operable or placed in service.

G3. The out-of-service date should be the year and season that the facility will be retired or taken out of service.

G4. All data should be screened to detect inappropriate or inaccurate data.

G5. The reactive limits of generators should be periodically reviewed and field tested, as appropriate, to ensure that reported var limits are attainable. (See Generation Equipment Standard II.B.)

G6. Generating station service load (SSL) and auxiliary load representations should be provided to those entities responsible for the reliability of the interconnected transmission systems on request. The presence of SSL in a dynamic simulation will alter the bus angles derived from solution. This change in angle can be significant from the steady-state, dynamic, and voltage control perspectives, especially for large generating units.

G7. To accurately model system inertia, the netting of generation and customer demand should be avoided. For smaller units, the netting of generation and load is acceptable.

G8. Generating units equal to or greater than 50 MVA should generally be individually modeled. To maintain sufficient detail in the model, larger units should not be lumped together.

G9. Smaller generating units at a particular station may be lumped together and represented as one unit. The lumping of generating units at a station is acceptable where all units have the same electrical and control characteristics. Equivalent lumped units should generally not exceed 300 MVA.

G10. The dynamics data for each generating unit should be supplied on the machine's own MVA and kV base.

G11. Data for generator step-up transformers that are modeled as part of the generator data record should include effective tap ratios and per unit impedance (R and X values) on the generator's MVA and kV base.

G12. Generator models should conform to *IEEE Guide for Synchronous Generator Modeling Practices in Stability Analyses* (IEEE Std. 1110-1991), or successor, Table 1, model 2.1 (for wound rotor machines) or 2.2 (for round rotor machines).

G13. Models of excitation systems, voltage regulators, and power system stabilizers should conform to *IEEE Recommended Practice for Excitation System Models for Power System Stability Studies* (IEEE Std. 421.5-1992), or successor, if a model appropriate to the equipment is available. If no model having the required characteristics is available, a library model or a user-written model of comparable detail with a block diagram may be supplied. "Computer Models for Representation of Digital-Based Excitation Systems", IEEE Working Group Report, *IEEE Transactions on Energy Conversion, Vol. 11., No. 3, September 1996*, should be considered in developing models of digital-based excitation systems.

G14. Models of turbine-governor systems for steam units should conform to IEEE Committee Report, "Dynamic Models for Steam and Hydro Turbines", as published in *IEEE Transactions on Power Apparatus and Systems, Nov./Dec. 1973*, model 1. If this model lacks the characteristics required to represent the dynamic response of the turbine-governor system within the required frequency range and time interval, a library model or a user-written model of comparable detail with a block diagram may be supplied. "Dynamic Models for Fossil Fueled Steam Units in Power System Studies", IEEE Working Group Report, *IEEE Transactions on Power Systems, Vol.6, No. 2, May 1991*, should be considered in developing models of steam turbine governor systems.

G15. Models of turbine-governor systems for hydro units should conform to IEEE Committee Report, "Dynamic Models for Steam and Hydro Turbines", as published in *IEEE Transactions on Power Apparatus and Systems, Nov./Dec. 1973,* model 2. If this model lacks the characteristics required to represent the dynamic response of the turbine-governor system within the required frequency range and time interval, a library model or a user-written model of comparable detail with a block diagram may be supplied. "Hydraulic Turbine and Turbine Control Models for System Dynamic Studies", IEEE Working Group Report, *IEEE Transactions on Power Systems, Vol.7., No. 1, February 1992*, should be considered in developing models of hydro turbine governor systems..

G16. Models of turbine-governor systems for combustion turbine units should represent appropriate gains, limits, time constants and damping, and should include a parameter explicitly setting the ambient temperature load limit if this limits unit output for ambient temperatures expected during the season under study. "Dynamic Models for Combined Cycle Plants in Power System Studies", IEEE Working Group Report, *IEEE Transactions on Power Systems, Vol.9., No. 3, August 1994*, should be considered in developing models of combustion turbine governor systems.

Brief Description Regional procedures for generation equipment testing.

Section II. System Modeling Data Requirements
B. Generation Equipment

Standard

S1. Generation equipment shall be tested to verify that data submitted for steady-state and dynamics modeling in planning and operating studies is consistent with the actual physical characteristics of the equipment. The data to be verified and provided shall include generator gross and net dependable capability, gross and net reactive power capability, voltage regulator controls, speed/load governor controls, and excitation systems.

Measurement

M1. Each Region shall establish and maintain procedures for generation equipment data verification and testing for all types of generating units in its Region. These procedures shall address generator gross and net dependable capability, reactive power capability, voltage regulator controls, speed/load governor controls, and excitation systems (including power system stabilizers and other devices, if applicable). These procedures shall also address generating unit exemption criteria and shall require documentation of those generating units that are exempt from a portion or all of these procedures.

Applicable to

Regions.

Items to be Measured

Procedures for validating generation equipment data.

Timeframe

On request (five business days).

Full (100%) Compliance Requirement

Each Region shall establish, maintain, and document procedures for generation equipment data verification and testing for all non-exempt generating units in its Region. The equipment to be tested and the data to be reported shall include, as a minimum, those items specified under Measurements M1, M2, M3, M4, M5, and M6 of this Standard II.B. S1. The schedule for the testing of the generation equipment, as defined in Measurements M2, M3, M4, M5, and M6, and the schedule for the submittal of the verification or test data to the Regions shall be included in the Regional procedures. Each Region shall also develop the criteria under which generation equipment may be exempt from a portion or all of the required testing procedures. A list of the exempt units shall be maintained by each Region. Documentation of verification and testing procedures shall be available to all reporting parties on request (five business days).

Levels of Non-Compliance

Level 1

Documentation of Regional procedures for generation equipment testing was provided on schedule, but was incomplete in one or more areas.

Level 2
Documentation of Regional procedures for generation equipment testing was not provided on schedule, but was complete when submitted.

Level 3
Documentation of Regional procedures for generation equipment testing was not provided on schedule, and was incomplete in one or more areas when submitted.

Level 4
Documentation of Regional procedures for generation equipment testing was not provided.

Compliance Monitoring Responsibility

NERC.

Reviewer Comments on Compliance Rating

Brief Description
Verification of gross and net real power dependable capability of generators.

Section
II. System Modeling Data Requirements
B. Generation Equipment

Standard
S1. Generation equipment shall be tested to verify that data submitted for steady-state and dynamics modeling in planning and operating studies is consistent with the actual physical characteristics of the equipment. The data to be verified and provided shall include generator gross and net dependable capability, gross and net reactive power capability, voltage regulator controls, speed/load governor controls, and excitation systems.

Measurement
M2. Generation equipment owners shall annually test to verify the gross and net dependable capability of their units. They shall provide the Regions with the following information on request:

- **a. Summer and winter gross and net capabilities of each unit based on the power factor level expected for each unit at the time of summer and winter peak demand, respectively.**
- **b. Active or real power requirements of auxiliary loads.**
- **c. Date and conditions during tests (ambient and design temperatures, generator loading, voltages, hydrogen pressure, high-side voltage, and auxiliary loads).**

Applicable to
Generation equipment owners.

Items to be Measured
Verification of gross and net dependable capability of generators.

Timeframe
Annually.

Full (100%) Compliance Requirement
Generation equipment owners shall test annually all of their non-exempt generation equipment for summer and winter gross and net real power (MW) dependable capability according to the Regional procedures under Measurement M1 of this Standard II.B. S1. Operating data may be acceptable as test data providing it was obtained under test-like conditions.

Test conditions and test results shall be documented and all data requested by the Region shall be provided by the generation equipment owners in accordance with the Regional procedures in Measurement M1 of Standard II.B. S1. Exceptions to the schedules in the Regional procedures will need to be agreed to by the Region and the generation equipment owners.

Levels of Non-Compliance
Level 1
Verification of generator gross and net real power dependable capability was provided on schedule, but was incomplete in one or more areas.

Level 2
Verification of generator gross and net real power dependable capability was not provided on schedule, but was complete when submitted.

Level 3
Verification of generator gross and net real power dependable capability was not provided on schedule, and was incomplete in one or more areas when submitted.

Level 4
Verification of generator gross and net real power dependable capability was not provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description

Verification of gross and net reactive power capability of generators.

Section

II. System Modeling Data Requirements
B. Generation Equipment

Standard

S1. Generation equipment shall be tested to verify that data submitted for steady-state and dynamics modeling in planning and operating studies is consistent with the actual physical characteristics of the equipment. The data to be verified and provided shall include generator gross and net dependable capability, gross and net reactive power capability, voltage regulator controls, speed/load governor controls, and excitation systems.

Measurement

M3. Generation equipment owners shall test to verify the gross and net reactive power capability of their units at least every five years. They shall provide the Regions with the following information on request:

a. Maximum sustained reactive power capability (both lagging and leading) as a function of real power output and generator terminal voltage. If safety or system conditions do not allow testing to full capability, computations and engineering reports of estimated capability shall be provided.
b. Reason for reactive power limitation.
c. Reactive power requirements of auxiliary loads.
d. Date and conditions during tests (ambient and design temperatures, generator loading, voltages, hydrogen pressure, high-side voltage, and auxiliary loads).

Applicable to

Generation equipment owners.

Items to be Measured

Verification of gross and reactive power capability of generators.

Timeframe

At least every five years.

Full (100%) Compliance Requirement

Generation equipment owners shall test at least every five years all of their non-exempt generating units for reactive power capability according to the Regional procedures required under Measurement M1 of this Standard II.B. S1.

Test conditions and test results shall be documented and all data requested by the Region shall be provided by the generation equipment owners in accordance with the Regional procedures in Measurement M1 of Standard II.B. S1. Exceptions to the schedules in the Regional procedures will need to be agreed to by the Region and the generation equipment owners.

Levels of Non-Compliance

Level 1
Verification of generator gross and net reactive power capability was provided on schedule, but was incomplete in one or more areas.

Level 2
Verification of generator gross and net reactive power capability was not provided on schedule, but was completed when submitted.

Level 3
Verification of generator gross and net reactive power capability was not provided on schedule, and was incomplete in one or more areas when submitted.

Level 4
Verification of generator gross and net reactive power capability was not provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description

Test results of generator voltage regulator controls and limit functions.

Section

II. System Modeling Data Requirements
B. Generation Equipment

Standard

S1. Generation equipment shall be tested to verify that data submitted for steady-state and dynamics modeling in planning and operating studies is consistent with the actual physical characteristics of the equipment. The data to be verified and provided shall include generator gross and net dependable capability, gross and net reactive power capability, voltage regulator controls, speed/load governor controls, and excitation systems.

Measurement

M4. Generation equipment owners shall test voltage regulator controls and limit functions at least every five years. Upon request, they shall provide the Regions with the status of voltage regulator testing as well as information that describes how generator controls coordinate with the generator's short-term capabilities and protective relays. Test reports shall include minimum and maximum excitation limiters (volts/hertz), gain and time constants, the type of voltage regulator control function, date tested, and the voltage regulator control setting.

Applicable to

Generation equipment owners.

Items to be Measured

Test results of generator voltage regulator controls and limit functions.

Timeframe

At least every five years.

Full (100%) Compliance Requirement

Generation equipment owners shall test at least every five years all of their non-exempt voltage regulator controls and limit functions in accordance with Measurement M4 above and the Regional procedures required under Measurement M1 of this Standard II.B. S1.

All test data and status information requested by the Region shall be provided by the generation equipment owners in accordance with the Regional procedures in Measurement M1 of Standard II.B. S1. Exceptions to the schedules in the Regional procedures will need to be agreed to by the Region and the generation equipment owners.

Levels of Non-Compliance

Level 1

Test results of generator voltage regulator controls and limit functions were provided on schedule, but were incomplete in one or more areas.

Level 2

Test results of generator voltage regulator controls and limit functions were not provided on schedule, but were complete when submitted.

Level 3
Test results of generator voltage regulator controls and limit functions were not provided on schedule, and were incomplete in one or more areas when submitted.

Level 4
Test results of generator voltage regulator controls and limit functions were not provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description Test results of speed/load governor controls.

Section II. System Modeling Data Requirements
B. Generation Equipment

Standard

S1. Generation equipment shall be tested to verify that data submitted for steady-state and dynamics modeling in planning and operating studies is consistent with the actual physical characteristics of the equipment. The data to be verified and provided shall include generator gross and net dependable capability, gross and net reactive power capability, voltage regulator controls, speed/load governor controls, and excitation systems.

Measurement

M5. Generation equipment owners shall test speed/load governor controls at least every five years. Upon request, they shall provide the Regions with the status of governor tests as well as information that describes the characteristics (droop and deadband) of the speed/load governing system.

Applicable to

Generation equipment owners.

Items to be Measured

Test results of speed/load governor controls.

Timeframe

At least every five years.

Full (100%) Compliance Requirement

Generation equipment owners shall test at least every five years all of their non-exempt speed/load governor controls according to the Regional procedures required under Measurement M1 of this Standard II.B. S1. They shall also provide on request (within 30 days) information on the characteristics (droop and deadband) of the speed/load governing system.

All test data and status information requested by the Region shall be provided by the generation equipment owners in accordance with the Regional procedures in Measurement M1 of Standard II.B. S1. Exceptions to the schedules in the Regional procedures will need to be agreed to by the Region and the generation equipment owners.

Levels of Non-Compliance

Level 1

Test results of speed/load governor controls were provided on schedule, but were incomplete in one or more areas.

Level 2

Test results of speed/load governor controls were not provided on schedule, but were complete when submitted.

Level 3
Test results of speed/load governor controls were not provided on schedule, and were incomplete in one or more areas when submitted.

Level 4
Test results of speed/load governor controls were not provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description

Verification of excitation system dynamic modeling data.

Section

II. System Modeling Data Requirements
B. Generation Equipment

Standard

S1. Generation equipment shall be tested to verify that data submitted for steady-state and dynamics modeling in planning and operating studies is consistent with the actual physical characteristics of the equipment. The data to be verified and provided shall include generator gross and net dependable capability, gross and net reactive power capability, voltage regulator controls, speed/load governor controls, and excitation systems.

Measurement

M6. Generation equipment owners shall verify the dynamic model data for excitation systems (including power system stabilizers and other devices, if applicable) at least every five years. Design data for new or refurbished excitation systems shall be provided at least one year prior to the in-service date with updated data provided once the unit is in service. Open circuit test response chart recordings shall be provided showing generator field voltage and generator terminal voltage. (Brushless units shall include exciter field voltage and current.)

Applicable to

Generation equipment owners.

Items to be Measured

Verification of excitation system dynamic modeling data.

Timeframe

At least every five years.

Full (100%) Compliance Requirement

Generation equipment owners shall provide at least every five years data to verify the dynamic model for excitation systems of non-exempt generator units in accordance with Measurement M6 above and the Regional procedures required under Measurement M1 of this Standard II.B. S1. They shall also provide design data for new or refurbished excitation systems in accordance with Measurement M6 above.

All data verification and test results requested by the Region shall be provided by the generation equipment owners in accordance with the Regional procedures in Measurement M1 of Standard II.B. S1. Exceptions to the schedules in the Regional procedures will need to be agreed to by the Region and the generation equipment owners.

Levels of Non-Compliance

Level 1
Verification of excitation system dynamic modeling data was provided on schedule, but was incomplete in one or more areas.

Level 2
Verification of excitation system dynamic modeling data was not provided on schedule, but was complete when submitted.

Level 3
Verification of excitation system dynamic modeling data was not provided on schedule, and was incomplete in one or more areas when submitted.

Level 4
Verification of excitation system dynamic modeling data was not provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

II. System Modeling Data Requirements
B. Generation Equipment

G1. The following guidelines should be observed during testing of the reactive power capability of a generator:

a. The reactive power capability curve for each generating unit should be used to determine the expected reactive power capability.

b. Units should be tested while maintaining the scheduled voltage on the system bus. Coordination with other units may be necessary to maintain the scheduled voltage.

c. Hydrogen pressure in the generating unit should be at rated operating pressure.

d. Overexcited tests should be conducted for a minimum of two hours or until temperatures have stabilized.

e. When the maximum sustained reactive power output during the test is achieved, the following quantities should be recorded: generator gross MW and Mvar output, auxiliary load MW and Mvar, and generator and system voltage magnitudes.

G2. Most modern voltage regulators have limiting functions that act to bring the generating unit back within its capabilities when the unit experiences excessive field voltage, volts per hertz, or underexcited reactive current. These limiters are often intended to coordinate with other controls and protective relays. Testing should be done that demonstrates correct action of the controls and confirms the desired set points.

G3. Generation equipment owners should make a best effort to verify data necessary for system dynamics studies. An “open circuit step in voltage” is an easy to perform test that can be used to validate the generating unit and excitation system dynamics data. The open circuit test should be performed with the unit at rated speed and voltage but with its breakers open. Generator terminal voltage, field voltage, and field current (exciter field voltage and current for brushless excitation systems) should be recorded with sufficient resolution such that the change in voltages and current are clearly distinguishable.

G4. More detailed test procedures should be performed when there are significant differences between “open circuit step in voltage” tests and the step response predicted with the model data. Generator reactance and time constant data can be derived from standstill frequency response tests.

G5. The response of the speed/load governor controls should be evaluated for correct operation whenever there is a system frequency deviation that is greater than that established by the Regional procedures.

Brief Description Methodology(ies) for determining electrical facility ratings.

Category Documentation

Section II. System Modeling Data Requirements
C. Facility Ratings

Standard

S1. Electrical facilities used in the transmission and storage of electricity shall be rated in compliance with applicable Regional requirements.

Measure

M1. Facility owners shall document the methodology(s) used to determine their electrical facility and equipment rating. Further, the methodology(s) shall be compliant with applicable Regional requirements.

The documentation shall address and include:

1. The methodology(s) used to determine facility and equipment rating of the items listed for both normal and emergency conditions:
   a. Transmission circuits
   b. Transformers
   c. Series and shunt reactive elements
   d. Terminal equipment (e.g., switches, breakers, current transformers, etc.)
   e. VAR compensators (SVC)
   f. High voltage direct current (HVDC) converters
   g. Any other device listed as a limiting element
2. The rating of a facility shall not exceed the rating(s) of the most limiting element(s) in the circuit, including terminal connections and associated equipment.
3. In cases where protection systems and control settings constitute a loading limit on a facility, this limit shall become the rating for that facility.
4. Ratings of jointly-owned and jointly-operated facilities shall be coordinated among the joint owners and joint operators resulting in a single set of ratings.
5. The documentation shall identify the assumptions used to determine each of the facility and equipment ratings, including references to industry rating practices and standards (e.g., ANSI, IEEE, etc.). Seasonal ratings and variations in assumptions shall be included.

The documentation of the methodology(s) used to determine transmission facility and equipment ratings shall be provided to the Regions and NERC on request (30 days).

Applicable to

Facility owners

Items to be Measured

Methodology(s) used for determining facility and equipment ratings.

Timeframe

On request (30 days).

Levels of Non-Compliance

Level 1 — Facility and equipment rating methodology(s) do not address one of the requirements listed in the above Measurement M1.

Level 2 — N/A

Level 3 — Facility and equipment rating methodology(s) do not address two of the requirements listed in the above Measurement M1.

Level 4 — Facility and equipment rating methodology(s) do not address three or more of the requirements listed in the above Measurement M1, or no facility and equipment rating methodology was provided.

Compliance Monitoring Responsibility

Regional Reliability Councils. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Brief Description Electrical facility ratings for system modeling.

Category Data

Section II. System Modeling Data Requirements
C. Facility Ratings

Standard

S1. Electrical facilities used in the transmission and storage of electricity shall be rated in compliance with applicable Regional, subregional, power pool, and individual transmission provider/owner planning criteria.

Measurement

M2. Facility owners shall have on file, or be able to readily provide, a document or data base identifying the normal and emergency ratings of all of their transmission facilities (e.g., lines, transformers, reactive devices, terminal equipment, and storage devices) that are part of the bulk interconnected transmission systems. Seasonal variations in ratings shall be included as appropriate.

The ratings shall be consistent with the methodology(ies) for determining facility ratings (Standard II.C. S1, M1) and shall be updated as facility changes occur. The rating*s* shall be provided to the Regions and NERC on request (30 business days).

Applicable to

Facility owners.

Items to be Measured

Electrical facility ratings (normal and emergency, as appropriate).

Timeframe

On request (30 days).

Levels of Non-Compliance

Level 1
Facility ratings were incomplete or the methodology(ies) inconsistently applied in one facility type.

Level 2
Facility ratings were incomplete or the methodology(ies) inconsistently applied in two facility types.

Level 3
Facility ratings were incomplete or the methodology(ies) inconsistently applied in three or more facility types.

Level 4
Facility ratings were not provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

II. System Modeling Data Requirements
C. Facility Ratings

G1. System modeling should use facility ratings based on weather assumptions appropriate for the seasonal (demand) conditions being evaluated.

G2. Facility ratings should be based on or adhere to applicable national electrical codes and electric industry rating practices consistent with good engineering practice.

G3. The ratings of bypass equipment do not need to be included in the facility rating determination. However, if it is the most limiting element, it should be identified and made available to the system operator. If an equipment failure results in extended use of bypass equipment, then the facility rating should be adjusted in the model and the Region and impacted operating entities should be informed.

Brief Description Documentation of data reporting requirements for actual and forecast demands, net energy for load, and controllable demand-side management.

Category Documentation

Section
II. System Modeling Data Requirements
D. Actual and Forecast Demands

Standards

S1. Actual demands and net energy for load data shall be provided on an aggregated Regional, subregional, power pool, individual system, or load serving entity basis. Actual demand data on a dispersed substation basis shall be supplied when requested.

Forecast demands and net energy for load data shall be developed and maintained on an aggregated Regional, subregional, power pool, individual system, or load serving entity basis. Forecast demand data shall also be developed on a dispersed substation basis.

S2. Controllable demand-side management (interruptible demands and direct control load management) programs and data shall be identified and documented.

Measurement

M1. The entities responsible for the reliability of the interconnected transmission systems, in conjunction with the Regions, 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 demand-side management data to be reported for system modeling and reliability analyses.

The aggregated and dispersed data submittal requirements shall ensure that consistent data is supplied for Standards IB, IIA, and IID.

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

Applicable to

Entities responsible for the reliability of the interconnected transmission systems and the Regions.

Items to be Measured

Scope and details of demand, net energy for load, and controllable demand-side management data and reporting procedures.

Timeframe

On request (five business days).

Levels of Non-Compliance

Level 1

The Region and the entities responsible for the reliability of the interconnected transmission systems have identified the scope and details of demand, net energy for load, and controllable demand-side management data to be reported and the reporting procedures but have not specified that consistent data is to be supplied for Standards IB, IIA, and IID.

Level 2
Not applicable.

Level 3
Not applicable.

Level 4
The Region and the entities responsible for the reliability of the interconnected transmission systems have not identified the scope and details of demand, net energy for load, and controllable demand-side management data to be reported and the reporting procedures.

Compliance Monitoring Responsibility

Regions and NERC.

Reviewer Comments on Compliance Rating

Brief Description

Reporting procedures to ensure against double counting or the omission of customer demand data.

Section

II. System Modeling and Data Requirements
D. Actual and Forecast Demands

Standard

S1. Actual and forecast customer demands and net energy for load data required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained on an aggregated Regional, subregional, power pool, and individual system basis and on a dispersed substation basis.

Measurement

M2. The reporting procedures that are developed shall ensure that customer demands are not double counted or omitted in reporting actual or forecast demand data on either an aggregated or dispersed basis within an area or Region.

Applicable to

Entities responsible for the reliability of the interconnected transmission systems in conjunction with the Regions.

Items to be Measured

Reporting procedures that ensure against double counting or the omission of customer demand data.

Timeframe

On request (five business days).

Full (100%) Compliance Requirement

The data reporting procedures shall adequately address prevention of double counting, the omission of data in accordance with Measurement M2 above, and shall be available on request (five business days) to the Regions and NERC.

Levels of Non-Compliance

Level 1
Reporting procedures that address double counting and the omission of data were provided on schedule, but were incomplete in one or more areas.

Level 2
Reporting procedures that address double counting and the omission of data were not provided on schedule, but were complete when submitted.

Level 3
Reporting procedures that address double counting and the omission of data were not provided on schedule, and were incomplete in one or more areas when submitted.

Level 4
Reporting procedures that address double counting and the omission of data were not provided.

Compliance Monitoring Responsibility

Regions and NERC.

Reviewer Comments on Compliance Rating

Brief Description

Consistency of actual and forecast demands and controllable demand-side management data reported for reliability and to government agencies.

Section

II. System Modeling and Data Requirements
D. Actual and Forecast Demands

Standards

S1. Actual and forecast customer demands and net energy for load data required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained on an aggregated Regional, subregional, power pool, and individual system basis and on a dispersed substation basis.

S2. Controllable demand-side management (interruptible demands and direct control load management) programs and data shall be identified and documented.

Measurement

M3. Actual and forecast customer demand data and controllable demand-side management data reported to government agencies shall be consistent with data reported to those entities responsible for the reliability of the interconnected transmission systems, the Regions, and NERC.

Applicable to

Entities required to report actual and forecast demand data.

Items to be Measured

Procedures requiring consistency of data reported for reliability purposes and to government agencies.

Timeframe

Annually or as specified in the documentation (Standard II.D. S1-S2, M1).

Full (100%) Compliance Requirement

The procedures shall require consistency in reporting actual and forecast demands and controllable demand-side management data for reliability purposes and to government agencies**.**

Levels of Non-Compliance

Level 1
Consistent demand data was provided on schedule, but was incomplete in one or more areas.

Level 2
Consistent demand data was not provided on schedule, but was complete when submitted.

Level 3
Consistent demand data was not provided on schedule, and was incomplete in one or more areas when submitted.

Level 4
Consistent demand data was not provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description	Aggregated actual and forecast demands and net energy for load.
Category	Data
Section	II. System Modeling Data Requirements D. Actual and Forecast Demands

Standard

S1. Actual demands and net energy for load data shall be provided on an aggregated Regional, subregional, power pool, individual system, or load serving entity basis. Actual demand data on a dispersed substation basis shall be supplied when requested.

Forecast demands and net energy for load data shall be developed and maintained on an aggregated Regional, subregional, power pool, individual system, or load serving entity basis. Forecast demand data shall also be developed on a dispersed substation basis.

Measurement

M4. The following information shall be provided annually on an aggregated Regional, subregional, power pool, individual system, or load serving entity basis to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems as specified by the documentation in Standard II.D. S1-S2, M1.

1. **Integrated hourly demands in megawatts (MW) for the prior year.**
2. **Monthly and annual peak hour actual demands in MW and net energy for load in gigawatthours (GWh) for the prior year.**
3. **Monthly peak hour forecast demands in MW and net energy for load in GWh for the next two years.**
4. **Annual peak hour forecast demands (summer and winter) in MW and annual net energy for load in GWh for at least five years and up to ten years into the future, as requested.**

Applicable to

Entities required by the Region to report actual and forecast demand data.

Items to be Measured

Aggregated actual and forecast demand and net energy for load data.

Timeframe

Annually or as specified in the documentation (Standard II.D. S1-S2, M1).

Levels of Non-Compliance

Level 1

Entities required by the Region to report actual and forecast demands did not provide actual and forecast demands and net energy for load data in one of the four areas as required in the above Measurement M4.

Level 2
Entities required by the Region to report actual and forecast demands did not provide actual and forecast demands and net energy for load data in two of the four areas as required in the above Measurement M4**.**

Level 3
Entities required by the Region to report actual and forecast demands did not provide actual and forecast demands and net energy for load data in three of the four areas as required in the above Measurement M4**.**

Level 4
Entities required by the Region to report actual and forecast demands did not provide actual and forecast demands and net energy for load data in any of the the areas as required in the above Measurement M4**.**

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description Treatment of nonmember demand data and how uncertainties are addressed in the forecasts of demand and net energy for load.

Category Documentation

Section II. System Modeling Data Requirement
D. Actual and Forecast Demands

Standard

S1. Actual demands and net energy for load data shall be provided on an aggregated Regional, subregional, power pool, individual system, or load serving entity basis. Actual demand data on a dispersed substation basis shall be supplied when requested.

Forecast demands and net energy for load data shall be developed and maintained on an aggregated Regional, subregional, power pool, individual system, or load serving entity basis. Forecast demand data shall also be developed on a dispersed substation basis.

Measurement

M6. The actual and forecast demand data reported on either an aggregated or dispersed basis shall:

a) indicate whether the demand data of nonmember entities within an area or Region are included, and

b) address assumptions, methods, and the manner in which uncertainties are treated in the forecasts of aggregated peak demands and net energy for load.

Full compliance requires items (a) and (b) to be addressed as described in the reporting procedures developed for Measurement M1 of this Standard II.D. Current information on items a) and b) shall be reported to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems on request (within 30 days).

Applicable to

Entities required by the Region to report actual and forecast demand data.

Items to be Measured

a) Treatment of actual and forecast demand data of nonmember entities.
b) Information on assumptions, methods, and how uncertainties are addressed in the forecasts of demand and net energy for load data.

Timeframe

On request (within 30 days).

Levels of Non-Compliance

Level 1
Information on items a) or b) was not provided.

Level 2
Information on items a) and b) was not provided.

Level 3
Not applicable.

Level 4
Not applicable.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description Reporting of interruptible demands and direct control load management.

Category Data

Section II. System Modeling Data Requirements
D. Actual and Forecast Demands

Standard

S2. Controllable demand-side management (interruptible demands and direct control load management) programs and data shall be identified and documented.

Measurement

M10. Forecasts of interruptible demands and direct control load management data shall be provided annually for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems as specified by the documentation in Standard II.D. S1-S2, M1.

Applicable to

Entities required by the Regions to report actual and forecast demand data.

Items to be Measured

Interruptible demands and direct control load management data.

Timeframe

Annually or as specified in the documentation (Standard II.D. S1-S2, M1).

Levels of Non-Compliance

Level 1
Not applicable.

Level 2
Not applicable.

Level 3
Not applicable.

Level 4
The reporting entity did not provide the controlled demand-side management data as required in the above Measurement M10.

Compliance Monitoring Responsibility
Regions.

Reviewer Comments on Compliance Rating

Brief Description Interruptible demands and direct control load management data to be made known to system operators and security center coordinators.

Category Data

Section II. System Modeling Data Requirements
D. Actual and Forecast Demands

Standard

S2. Controllable demand-side management (interruptible demands and direct control load management) programs and data shall be identified and documented.

Measurement

M11. The amount of interruptible demands and direct control load management shall be made known to system operators and security center coordinators on request.

Full compliance requires the reporting of this data to system operators and security center coordinators within 30 days of a request.

Applicable to

Entities responsible for the reliability of the interconnected transmission systems.

Items to be Measured

Reporting of interruptible demands and direct control load management data to system operators and security center coordinators.

Timeframe

On request (within 30 days).

Levels of Non-Compliance

Level 1
Interruptible demands and direct control load management data were provided to system operators and security center coordinators, but were incomplete.

Level 2
Not applicable.

Level 3
Not applicable.

Level 4
Interruptible demands and direct control load management data were not provided to system operators and security center coordinators.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description Documentation of the method of accounting for the effects of controllable demand-side management in demand and energy forecasts.

Category Documentation

Section II. System Modeling Data Requirements
D. Actual and Forecast Demands

Standard

S2. Controllable demand-side management (interruptible demands and direct control load management) programs and data shall be identified and documented.

Measurement

M12. Forecasts shall clearly document how the demand and energy effects of demand-side management programs (such as conservation, time-of-use rates, interruptible demands, and direct control load management) are addressed.

Information detailing how demand-side management measures are addressed in the forecasts of peak demand and annual net energy for load shall be included in the data reporting procedures of Measurement M1 of this Standard II.D. Documentation on the treatment of demand-side management programs shall be available to NERC on request (within 30 days).

Applicable to

Entities required by the Region to report actual and forecast demand data.

Items to be Measured

How the effects of demand-side management programs are addressed in the forecasts of peak demand and annual net energy for load.

Timeframe

On request (within 30 days).

Levels of Non-Compliance

Level 1
Documentation on the treatment of demand-side management programs in the demand and energy forecasts was provided, but was incomplete.

Level 2
Not applicable.

Level 3
Not applicable.

Level 4
Documentation on the treatment of demand-side management programs in the demand and energy forecasts was not provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

II. System Modeling Data Requirements
D. Actual and Forecast Demands

G1. System modeling and reliability analyses may be required for more than a five-year period for several reasons including review or comparison of results from previous studies, regulatory requirements, long lead-time facilities (e.g., transmission lines), and government requirements (e.g., construction and/or environmental permits).

G2. Actual and forecast demand data and forecast controllable demand-side management data should be provided on either an aggregated or dispersed basis in an appropriate common format to ensure consistency in reporting and to facilitate use of the data by the entities responsible for the reliability of the interconnected transmission systems, the Regions, and NERC.

G3. Weather normalized data, when provided in addition to actual data, should be identified as such and reconciled as appropriate.

G4. The characteristics of demand-side management programs used in assessing future resource adequacy should generally include:

- consistent program ratings (demand and energy), including seasonal variations
- effect on annual load shape
- availability, effectiveness, and diversity
- contractual arrangements
- expected program duration
- effects (demand and energy) of multiple programs

Brief Description

Customer (dynamic) demand characteristics to be determined and reported for reliability analyses.

Section

II. System Modeling Data Requirements
E. Demand Characteristics (Dynamic)

Standard

S1. Representative frequency and voltage characteristics of customer demands (real and reactive power) required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained.

Measurement

M1. The entities responsible for the reliability of the interconnected transmission systems, in conjunction with the Regions, shall develop a plan for determining and promoting the accuracy of the representation of customer demands, identify the scope and specificity of the frequency and voltage characteristics of customer demands, and determine the procedures and schedule for data reporting.

Documentation of these customer demand characteristics (dynamic) plans and reporting procedures shall be provided to NERC and the Regions on request.

Applicable to

Entities responsible for the reliability of the interconnected transmission systems in conjunction with the Regions.

Items to be Measured

Plans for the evaluation and reporting of the voltage and frequency characteristics of customer demands.

Timeframe

On request (five business days).

Full (100%) Compliance Requirements

Entities responsible for the reliability of the interconnected transmission systems in conjunction with the Regions, as appropriate, shall develop and maintain a plan for determining and promoting the accuracy of the dynamic representation (e.g., frequency and voltage characteristics) of customer demands in accordance with Measurements M1 and M2 of this Standard II.E. S1. This plan shall also include the procedures and scheduling for the reporting of customer (dynamic) demand characteristics by load-serving entities. The documentation of this plan and procedures shall be available to the Regions and NERC on request (five business days).

Levels of Non-Compliance

Level 1
Documentation of a plan for determining and reporting the dynamic characteristics of customer demand was provided on schedule, but was incomplete in one or more areas.

Level 2
Documentation of a plan for determining and reporting the dynamic characteristics of customer demand was not provided, but was complete when submitted.

Level 3
Documentation of a plan for determining and reporting the dynamic characteristics of customer demand was not provided on schedule, and was incomplete in one or more areas when submitted.

Level 4
Documentation of a plan for determining and reporting the dynamic characteristics of customer demand was not provided.

Compliance Monitoring Responsibility

Regions and NERC.

Reviewer Comments on Compliance Rating

Brief Description

Requirements for determining customer (dynamic) demand characteristics to be included in procedural manuals.

Section

II. System Modeling Data Requirements
E. Demand Characteristics (Dynamic)

Standard

S1. Representative frequency and voltage characteristics of customer demands (real and reactive power) required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained.

Measurement

M2. The NERC System Dynamics Database Working Group or its successor group(s) shall maintain and publish customer demand characteristics requirements in its "procedural manual" pertaining to the Eastern Interconnection. Similar "procedural manuals" shall be maintained and published by the Western (WSCC), ERCOT, and Hydro-Québec[6] Interconnections. These procedural manuals shall include plans for determining and promoting the accuracy of the representation of customer demands.

Applicable to

Systems Dynamics Database Working Group (Eastern Interconnection), and the Western, ERCOT, and Hydro-Québec Interconnections.

Items to be Measured

Documentation of requirements for determining dynamic characteristics of customer demands.

Timeframe

On request (five business days).

Full (100%) Compliance Requirements

Procedural manuals for the Eastern, Western, ERCOT and Hydro-Québec Interconnections shall include the requirements for determining and promoting the accuracy of the dynamic representation of customer demands in accordance with Measurement M5 above and Measurements M4 and M5 of Standard II.A. These procedural manuals should be available to the Regions and NERC on request (five business days).

Levels of Non-Compliance

Level 1
Procedural manuals that include requirements for determining customer (dynamic) demand characteristics were provided on schedule, but were incomplete in one or more areas.

Level 2
Procedural manuals that include requirements for determining customer (dynamic) demand characteristics were not provided on schedule, but were complete when submitted.

[6] Hydro-Québec uses the Procedural Manual of the Eastern Interconnection.

Level 3
Procedural manuals that include requirements for determining customer (dynamic) demand characteristics were provided on schedule, and were incomplete in one or more areas when submitted.

Level 4
Procedural manuals that include requirements for determining customer (dynamic) demand characteristics were not provided.

Compliance Monitoring Responsibility
NERC.

Reviewer Comments on Compliance Rating

Brief Description

Load-serving entities to provide customer (dynamic) demand characteristics.

Section

II. System Modeling Data Requirements
E. Demand Characteristics (Dynamic)

Standard

S1. Representative frequency and voltage characteristics of customer demands (real and reactive power) required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained.

Measurement

M3. Load-serving entities shall provide customer demand characteristics to the Regions and those entities responsible for the reliability of the interconnected transmission systems in compliance with the respective procedural manuals for the modeling of portions or all of the four NERC Interconnections: Eastern, Western, ERCOT, and Hydro-Québec.[7]

Applicable to

Load-serving entities.

Items to be Measured

Customer (dynamic) demand characteristics.

Timeframe

As specified in the documentation (Standard II.E. S1, M1-M2).

Full (100%) Compliance Requirements

Load-serving entities shall provide customer demand characteristics in accordance with Measurement M3 above and the procedural manuals of Measurement M2 of this Standard II.E.

Levels of Non-Compliance

Level 1
Customer demand (dynamic) characteristics were provided on schedule, but were incomplete in one or more areas.

Level 2
Customer demand (dynamic) characteristics were not provided on schedule, but were complete when submitted.

Level 3
Customer demand (dynamic) characteristics were not provided on schedule, and were incomplete in one or more areas when submitted.

Level 4
Customer demand (dynamic) characteristics were not provided.

[7] Hydro-Québec uses the Procedural Manual of the Eastern Interconnection.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

II. System Modeling Data Requirements
E. Demand Characteristics (Dynamic)

G1. The representation of customer demands should generally include a combination of constant MVA, constant current, and constant impedance for real and reactive power components and frequency dependence, as appropriate.

G2. Special demand models for significant frequency and voltage dependent customer demands, such as fluorescent lighting or motors, should be provided on request.

G3. Demand characteristics for zones or areas within electric systems or at substation buses should reflect the composition of the demand at those locations.

G4. The voltage and frequency characteristics of customer demands that are used in system models should be representative of seasonal and time-of-day variations, as appropriate.

G5. The representation of customer demand characteristics should be periodically reviewed and field tested, as appropriate, to ensure the accuracy of the demand modeling.

G6. The sensitivity of simulation results to the demand models should be evaluated. High sensitivity demands (e.g., motors and certain substation demands) should generally be represented by more detailed models.

Brief Description Regional procedure on transmission protection misoperations.

Category Documentation

Section III. System Protection and Control
A. Transmission Protection Systems

Standard

S3. All transmission protection system misoperations shall be analyzed for cause and corrective action.

Measurement

M3. Each Region shall have a procedure for the monitoring, review, analysis, and correction of transmission protection system misoperations. The Regional procedure shall include the following elements:

1. **Requirements for monitoring and analysis of all transmission protective device misoperations.**
2. **Description of the data reporting requirements (periodicity and format) for those misoperations that adversely affect the reliability of the bulk electric systems as specified by the Region.**
3. **Process for review, follow up, and documentation of corrective action plans for misoperations.**
4. **Identification of the Regional group responsible for the procedure and the process for Regional approval of the procedure.**
5. **Regional definition of misoperations.**

Documentation of the Regional procedure shall be maintained and provided to NERC on request (within 30 days).

Applicable to

Regions.

Items to be Measured

Procedure for monitoring, review, analysis, and correction of all transmission protection system misoperations.

Timeframe

On request (within 30 days).

Levels of Non-Compliance

Level 1
The Regional procedure does not address all the requirements as defined above in Measurement M3.

Level 2
Not applicable.

Level 3
Not applicable.

Level 4
The Regional procedure was not provided.

Compliance Monitoring Responsibility

NERC.

Reviewer Comments on Compliance Rating

Brief Description Transmission Protection system maintenance and testing

Category Documentation and implementation

Section III. System Protection and Control
A. Transmission Protection Systems

Standard

S4. Transmission protection system maintenance and testing programs shall be developed and implemented.

Measure

M4. Transmission protection system owners shall have a system maintenance and testing program(s) in place. The program(s) shall include:

a. Transmission Protection system identification shall include but are not limited to:
   - relays
   - instrument transformers
   - communications systems, where appropriate
   - batteries

b. Documentation of maintenance and testing intervals and their basis
c. Summary of testing procedure
d. Schedule for system testing
e. Schedule for system maintenance
f. Date last tested/maintained

Documentation of the program and its implementation shall be provided to the appropriate Regions and NERC on request (within 30 days).

Applicable to

Transmission Protection system owner.

Items to be Measured

Documentation and implementation of transmission protection system maintenance and testing program.

Timeframe

On request (within 30 days).

Levels of Non-Compliance

Level 1 — Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.

Level 2 — Documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.

Level 3 — Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.

Level 4 — Documentation of the maintenance and testing program, or its implementation, was not provided.

Compliance Monitoring Responsibility

Regional Reliability Council. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Brief Description Analysis and reporting of transmission protection misoperations.

Category Documentation of implementation

Section III. System Protection and Control
A. Transmission Protection Systems

Standard

S3. All transmission protection system misoperations shall be analyzed for cause and corrective action.

Measurement

M5 Transmission protection system owners shall analyze all protection system misoperations and shall take corrective actions to avoid future misoperations.

Documentation of the misoperation analyses and corrective actions shall be provided to the affected Regions and NERC on request (within 30 days) according to the Regional procedures of Measurement III.A. S3, M3.

Applicable to

Transmission protection system owners.

Items to be Measured

Documentation of protection system misoperations, analyses, and corrective actions.

Timeframe

On request (within 30 days).

Levels of Non-Compliance

Level 1
Documentation of transmission protection system misoperations is complete according to Measurement III.A. S3, M3 but documentation of corrective actions taken for all identified misoperations is incomplete.

Level 2
Documentation of corrective actions taken for misoperations is complete but documentation of transmission protection system misoperations is incomplete according to Measurement III.A. S3, M3.

Level 3
Documentation of misoperations and corrective actions is incomplete.

Level 4
No documentation of misoperations or corrective actions was provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description Assessment of transmission control devices.

Section III. System Protection and Control
B. Transmission Control Devices

Standard

S1. Transmission control devices shall be planned and designed to meet the system performance requirements as defined in the I.A. Standards of the Transmission Systems and associated Table I. These devices shall be coordinated with other control devices within a Region and, where appropriate, with neighboring Regions.

Measurement

M1. When planning new or substantially modified transmission control devices, transmission owners shall evaluate the impact of such devices on the reliability of the interconnected transmission systems. The assessment shall include sufficient modeling of the details of the dynamic devices and encompass a variety of contingency system conditions. The assessment results shall be provided to the Regions and NERC on request.

Applicable to

Transmission owners.

Items to be Measured

Assessment of the reliability impact of transmission control devices.

Timeframe

On request (within 30 days).

Full (100%) Compliance Requirements

The performance of new or modified transmission control devices shall meet the requirements of Standard I.A. and its associated Table I. The analysis in support of this required performance may be included as part of the documentation for Standard I.A.

Evidence must be provided that the models used for the analysis adequately represent the response and operation of the transmission control devices.

A list of contingencies and system conditions tested must be provided along with a commentary on the sufficiency of these tests for the evaluation of the transmission control devices. The assessment results should be provided to the Regions and NERC on request (within 30 days).

Levels of Non-Compliance

Level 1
Assessments of the reliability impact of transmission control devices were provided on schedule, but were incomplete in one or more areas.

Level 2
Assessments of the reliability impact of transmission control devices were not provided on schedule, but were complete when submitted.

Level 3
Assessments of the reliability impact of transmission control devices were not provided on schedule, and were incomplete in one or more areas when submitted.

Level 4
Assessments of the reliability impact of transmission control devices were not provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description

Provision of models and data for control devices for use in system modeling.

Section

III. System Protection and Control
B. Transmission Control Devices

Standard

S1. **Transmission control devices shall be planned and designed to meet the system performance requirements as defined in the I.A. Standards of the Transmission Systems and associated Table I. These devices shall be coordinated with other control devices within a Region and, where appropriate, with neighboring Regions.**

Measurement

M2. **Transmission owners shall provide transmission control device models and data, suitable for use in system modeling, to the Regions and NERC on request. Preliminary data on these devices shall be provided prior to their in-service dates. Validated models and associated data shall be provided following installation and energization.**

Applicable to

Transmission owners.

Items to be Measured

Transmission control device models and data.

Timeframe

On request (within 30 days).

Full (100%) Compliance Requirements

Transmission owners shall provide transmission control device models and data suitable for use in system modeling. These models and data will be used in the assessments of the reliability of the transmission network under Standard I.A. Transmission owners shall provide preliminary models and data for transmission control devices to permit analysis of the potential impacts of these devices on system reliability prior to their installation. Validated models and data, based on commissioning test results, shall be provided after the in-service dates of the control devices so that the impacts of these devices on system security may be fully assessed and incorporated into operating security limits.

Validated transmission control device models and data should be provided to the Regions and NERC on request (within 30 days).

Levels of Non-Compliance

Level 1
Control device models and data for use in system modeling were provided on schedule, but were incomplete in one or more areas.

Level 2
Control device models and data for use in system modeling were not provided on schedule, but were complete when submitted.

Level 3
Control device models and data for use in system modeling were not provided on schedule, and were incomplete in one or more areas when submitted.

Level 4
Control device models and data for use in system modeling were not provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description Periodic review of settings and operating strategies of control devices.

Section III. System Protection and Control
B. Transmission Control Devices

Standard

S1. Transmission control devices shall be planned and designed to meet the system performance requirements as defined in the I.A. Standards of the Transmission Systems and associated Table I. These devices shall be coordinated with other control devices within a Region and, where appropriate, with neighboring Regions.

Measurement

M3. The transmission owners or operators shall document and periodically (at least every five years or as required by changes in system conditions) review the settings and operating strategies of the control devices. Documentation shall be provided to the Regions and NERC on request.

Applicable to

Transmission owners or operators.

Items to be Measured

Periodic review and validation of settings and operating strategies.

Timeframe

When conditions change or at least every five years.

Full (100%) Compliance Requirements

Transmission owners or operators shall review the settings and operating strategies of transmission control devices whenever changes to the system are made or at least every five years to ensure that these control devices continue to perform their intended function. Documentation of the current settings and operating strategies shall be provided to the Regions and NERC on request (within 30 days).

Levels of Non-Compliance

Level 1
A review of control device settings and operating strategies was provided on schedule, but was incomplete in one or more areas.

Level 2
A review of control device settings and operating strategies was not provided on schedule, but was complete when submitted.

Level 3
A review of control device settings and operating strategies was not provided on schedule, and was incomplete in one or more areas when submitted.

Level 4
A review of control device settings and operating strategies was not provided.

III. System Protection and Control
B. Transmission Control Devices

G1. Coordinated control strategies for the operation of transmission control devices may require switching surge studies, harmonic analyses, or other special studies.

G2. For HDVC links in parallel with ac lines, supplementary control should be considered so that the HDVC links provide synchronizing and damping power for interconnected generators. Use of HDVC links to stabilize system ac voltages should be considered.

Brief Description

Operation of all synchronous generators in the automatic voltage control mode.

Category

Documentation

Section

III. System Protection and Control
C. Generation Control and Protection

Standard

S1. **All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless approved otherwise by the transmission system operator.**

Measurement

M1. **Transmission system operators shall have procedures requiring synchronous generator owners/operators to provide the following information to them, the Region, and NERC on request (five business days):**

a. **Summary reports showing the number of hours each synchronous generator did not operate in the automatic voltage control mode during a specified time period, and**
b. **Detailed reports of the date, duration, and reason for each period when a synchronous generator was not operated in the automatic voltage control mode.**

The procedures shall require the generator owner/operator to retain the above information for 12 rolling months.

The procedures shall also specify criteria by which generators are to be exempt from the above requirements.

Applicable to

Transmission system operators.

Items to be Measured

Documentation of procedures for reporting when a synchronous generator is operated without automatic voltage control equipment in service.

Timeframe

On request (five business days).

Levels of Non-Compliance

Level 1
Transmission system operator has procedures for synchronous generator owners/operators to follow but they do not include all of the requirements of above Measurement M1.

Level 2
Not applicable.

Level 3
Not applicable.

Level 4

Transmission system operator has no procedures for synchronous generator owners/operators to follow to report generator operation in the non-automatic voltage control mode.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description
Operation of all synchronous generators in the automatic voltage control mode.

Category
Data

Section
III. System Protection and Control
C. Generation Control and Protection

Standard

S1. All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless approved otherwise by the transmission system operator.

Measurement

M2. Each synchronous generating unit shall be operated in the automatic voltage control mode unless otherwise approved by the transmission system operator.

Each synchronous generator owner/operator shall provide to the transmission system operator, the Region, and NERC, on request (30 business days), information on the operation of the synchronous generator's excitation system according to the transmission system operator's procedures for synchronous generators as defined in Measurement III.C. S1, M1.

Applicable to

Generator owner/operator.

Items to be Measured

Information on the operation of synchronous generators in the non-automatic voltage control mode as defined in Measurement III.C. S1, M1.

Timeframe

On request (30 business days).

Levels of Non-Compliance

Level 1
Reports indicate incidents of synchronous generator operation without automatic voltage control for a total of less than 8 unit-hours, without permission from the transmission system operator.

Level 2
Reports indicate incidents of synchronous generator operation without automatic voltage control for a total of less than 16 unit-hours, without permission from the transmission system operator.

Level 3
Reports were incomplete, or indicate incidents of synchronous generator operation without automatic voltage control for a total of less than 24 unit-hours, without permission from the transmission system operator.

Level 4
Reports on the requested information were not provided, or indicate incidents of synchronous generator operation without automatic voltage control for a total of 24 unit-hours or more, without permission from the transmission system operator.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description Generator operation for maintaining network voltage schedules.

Category Data

Section III. System Protection and Control
C. Generation Control and Protection

Standard

S2. Synchronous generators shall maintain a network voltage or reactive power output as required by the transmission system operator within the reactive capability of the units. Generator step-up and auxiliary transformers shall have their tap settings coordinated with electric system voltage requirements.

Measurement

M3. Each transmission system operator shall specify a voltage or reactive schedule to be maintained by each synchronous generator at a specified bus and shall provide this information to the generator owner/operator. Documentation of the information provided to the generator owner/operator shall be provided to the Region and NERC on request (five business days).

Each transmission system operator shall maintain a list of synchronous generators that are exempt from the requirement of maintaining a network voltage or reactive schedule. The list of exempt generators shall be made available to the Region and NERC on request (five business days).

Applicable to

Transmission system operator/owner.

Items to be Measured

Documentation of the voltage or reactive schedule provided to synchronous generator owners/operators.
List of exempt synchronous generators.

Timeframe

On request (five business days).

Levels of Non-Compliance

Level 1
Not applicable.

Level 2
An incomplete list of exempt synchronous generators was provided.

Level 3
Incomplete documentation of the requested voltage or reactive schedule was provided.

Level 4
No documentation of the voltage or reactive schedule was provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description Generator operation for maintaining network voltage schedules.

Category Data

Section III. System Protection and Control
C. Generation Control and Protection

Standard

S2. Synchronous generators shall maintain a network voltage or reactive power output as required by the transmission system operator within the reactive capability of the units. Generator step-up and auxiliary transformers shall have their tap settings coordinated with electric system voltage requirements.

Measurement

M4. Synchronous generator owners/operators shall maintain the voltage or reactive output as specified by the transmission system operator, unless otherwise approved by the transmission system operator.

When requested by the Region and NERC, the synchronous generator owner/operator shall provide (30 business days) 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 system operator.

Applicable to

Generator owner/operator.

Items to be Measured

Log of date, duration, and reason for each specified period when the synchronous generator did not maintain the established network voltage or reactive power schedule, with documentation of any approvals for such operation received from the transmission system operator.

Timeframe

On request (30 business days).

Levels of Non-Compliance

Level 1
Logs indicate incidents of synchronous generator operation off the voltage or reactive schedule for a total of less than 8 unit-hours, without permission from the transmission system operator.

Level 2
Logs indicate incidents of synchronous generator operation off the voltage or reactive schedule for a total of less than 16 unit-hours, without permission from the transmission system operator.

Level 3
Logs of synchronous generator operation off the voltage or reactive schedule were incomplete, or the logs indicate incidents of operating off the voltage or reactive schedule for a total of less than 24 unit-hours, without permission from the transmission system operator.

Level 4
Logs of synchronous generator operation off the voltage or reactive schedule were not provided, or the logs indicate incidents of operating off the voltage or reactive schedule for a total of 24 unit-hours or more, without permission from the transmission system operator.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description
Tap settings of generator step-up and auxiliary transformers.

Category
Documentation

Section
III. System Protection and Control
C. Generation Control and Protection

Standard
S2. Synchronous generators shall maintain a network voltage or reactive power output as required by the transmission system operator within the reactive capability of the units. Generator step-up and auxiliary transformers shall have their tap settings coordinated with electric system voltage requirements.

Measurement
M5. The transmission system operator shall have procedures requiring synchronous generator owners/operators to provide tap settings, available tap ranges, and impedance data for generator step-up and auxiliary transformers. When tap changes are necessary, the transmission system operator shall provide the generator owner/operator with a report that specifies the required tap changes and technical justification for these changes. The procedures for reporting the data shall also address generating unit exemption criteria (including any that may apply to nuclear units) and shall require documentation of those generating units that are exempt from a portion or all of these reporting requirements.

Documentation of these procedures shall be provided to the Region and NERC on request (five business days).

Applicable to
Transmission system operator.

Items to be Measured
Procedures for reporting synchronous generator step-up and auxiliary transformer tap settings and available tap ranges.

Timeframe
Procedures on request (five business days).

Levels of Non-Compliance
Level 1
Procedures exist but do not include all the requirements as defined in above Measurement M5.

Level 2
Not applicable.

Level 3
Not applicable.

Level 4
Procedures were not provided.

Compliance Monitoring Responsibility
Regions.

Reviewer Comments on Compliance Rating

Brief Description Tap settings of generator step-up and auxiliary transformers.

Category Data

Section III. System Protection and Control
C. Generation Control and Protection

Standard

S2. Synchronous generators shall maintain a network voltage or reactive power output as required by the transmission system operator within the reactive capability of the units. Generator step-up and auxiliary transformers shall have their tap settings coordinated with electric system voltage requirements.

Measurement

M6. A synchronous generator owner/operator shall provide the tap settings and the available tap ranges and impedance data for generator step-up and auxiliary transformers to the transmission system operator, the Region, and NERC on request (five business days).

A generator owner/operator shall change tap positions according to the procedures provided by the transmission system operator within a mutually agreed upon time frame as defined in Measurement III.C. S2, M5.

Applicable to

Generator owner/operator.

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Items to be Measured

Reporting of tap settings, available tap ranges, and impedances for generator step-up and auxiliary transformers.

Timeframe

On request (five business days).

Levels of Non-Compliance

Level 1
Report does not include all the information requested as defined in Measurement III.C. S2, M5.

Level 2
Not applicable.

Level 3
Not applicable.

Level 4
Report on tap settings, available tap ranges, and impedances for generator step-up and auxiliary transformers was not provided, or report indicates generator owner/operator did not change tap settings as requested by the transmission system operator during the mutually agreed upon time frame.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description Generators performance during temporary excursions in frequency, voltage, etc.

Category Documentation

Section III. System Protection and Control
C. Generation Control and Protection

Standard

S3. Temporary excursions in voltage, frequency, and real and reactive power output that a generator shall be able to sustain shall be defined and coordinated on a Regional basis.

Measurement

M7. The Regions shall establish requirements for generators to remain interconnected during temporary excursions in voltage, frequency, and real and reactive power output. These requirements shall include generator exemption criteria.

Documentation of these excursion requirements shall be available to the transmission system operator and NERC upon request (30 business days).

Applicable to

Regions.

Items to be Measured

Requirements for withstanding temporary excursions in voltage, frequency, and real and reactive power output of a generator.

Timeframe

On request (30 business days).

Levels of Non-Compliance

Level 1
Documentation of Regional requirements provided does not address all three generator parameters (voltage, frequency, or real and reactive power output).

Level 2
Not applicable.

Level 3
Not applicable.

Level 4
Documentation of Regional requirements was not provided.

Compliance Monitoring Responsibility

NERC.

Reviewer Comments on Compliance Rating

Brief Description Coordination of generator controls with the generator's short-term capabilities and protective relays.

Category Data

Section III. System Protection and Control
C. Generation Control and Protection

Standard

S4. Voltage regulator controls and limit functions (such as over and under excitation and volts/hertz limiters) shall coordinate with the generator's short duration capabilities and protective relays.

Measurement

M8. Generator owners/operators shall provide the Region, the transmission system operator, and NERC, as requested (30 business days), with information that ensures that the generator voltage regulator controls and limit functions (such as over and under excitation and volts/hertz limiters) coordinate with the generator's short-term capabilities and protective relays, unless exempted by the Region.

Applicable to

Generator owner/operator.

Items to be Measured

Information indicating coordination of generator voltage regulator controls and limit functions with the generator's short-term capabilities and protective relays.

Timeframe

On request (30 business days).

Levels of Non-Compliance

Level 1
Information on generator voltage regulator controls and limit functions and their coordination with the generator's short-term capabilities and protective relays was provided, but was incomplete in one or more areas.

Level 2
Not applicable.

Level 3
Not applicable.

Level 4
Information on generator controls and their coordination with the generator's short-term capabilities and protective relays was not provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description Speed/load governing system.

Category Data

Section III. System Protection and Control
C. Generation Control and Protection

Standard

S5. Prime mover control (governors) shall operate with appropriate speed/load characteristics to regulate frequency.

Measurement

M9. Generator owners/operators shall provide the Region, the transmission system operator, and NERC as requested (30 business days) with the characteristics of the generator's speed/load governing system. Boiler or nuclear reactor control shall be coordinated to maintain the capability of the generator to aid control of system frequency during an electric system disturbance. Non-functioning or blocked speed/load governor controls shall be reported to the Region, the transmission system operator, and NERC on request (30 business days).

Applicable to

Generator owner/operator.

Items to be Measured

Documentation of the characteristics of the generator's speed/load governing system and notification of blocked speed/load governor controls.

Timeframe

On request (30 business days).

Levels of Non-Compliance

Level 1
Information on the generator's speed/load governing system was provided but did not include all the requirements as defined above in Measurement M9.

Level 2
Not applicable.

Level 3
Not applicable.

Level 4
Information on the generator's speed/load governing system was not provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description Regional procedure on generator protection operations.

Category Documentation

Section III. System Protection and Control
C. Generation Control and Protection

Standard

S6. All generation protection system misoperations shall be analyzed for cause and corrective action.

Measurement

M10. Each Region shall have in place a procedure for the monitoring, review, analysis, and correction of generation protection system operations.

The procedure shall require that misoperations be analyzed for cause and that corrective actions be implemented. (Each Region shall define misoperations.) The procedure shall also require that a record of such analysis and corrective actions be maintained and be provided to the Region and NERC on request (five business days).

The Regional procedure shall include the following elements:

1. **Requirements for monitoring, analysis, and notification of all generation protective device misoperations.**
2. **List of the data reporting requirements (periodically and format).**
3. **Requirements for analysis and documentation of corrective action plans for misoperations.**
4. **Periodicity of review of the procedure by the Region.**
5. **Identification of the Regional group responsible for the procedure and the process for Regional approval of the procedure.**
6. **Regional definition of misoperation.**

Applicable to

Regions.

Items to be Measured

Procedure for monitoring, review, analysis, and correction of all generator protection operations.

Timeframe

On request (five business days).

Levels of Non-Compliance

Level 1
The Regional procedure does not address all the requirements as defined above in Measurement M10.

Level 2
Not applicable.

Level 3
Not applicable.

Level 4
The Regional procedure was not provided.

Compliance Monitoring Responsibility

NERC.

Reviewer Comments on Compliance Rating

Brief Description Analysis of misoperations of generator protection equipment.

Category Documentation and implementation

Section III. System Protection and Control
C. Generation Control and Protection

Standard

S6. All generation protection system misoperations shall be analyzed for cause and corrective action.

Measurement

M11. Generator owners/operators shall analyze protection system operations and report and maintain a record of all misoperations in accordance with Regional procedures in Measurement III.C. S6, M10. Corrective actions shall be taken to avoid future misoperations.

Documentation of the analysis and corrective actions shall be provided to the affected Regions and NERC on request (30 business days).

Applicable to

Generator owner/operator.

Items to be Measured

Documentation of protection misoperations, analyses, and corrective actions.

Timeframe

On request (30 business days).

Levels of Non-Compliance

Level 1
Documentation of generator protection system misoperations was provided but does not address all identified misoperations or does not provide a record of corrective actions taken for all identified misoperations.

Level 2
Documentation of generator protection system misoperations was provided but was lacking one of these three elements: (a) a complete record of misoperations for the time and place requested, (b) an analysis of all misoperations, and (c) a record of corrective actions taken.

Level 3
Documentation was provided but was lacking two of these three elements: (a) a complete record of misoperations for the time and place requested; (b) an analysis of all misoperations; (c) a record of corrective actions taken.

Level 4
No documentation of generator protection system misoperations was provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description Maintenance and testing of generator protection systems.

Category Documentation and implementation

Section III. System Protection and Control
C. Generation Control and Protection

Standard

S7. Generation protection system maintenance and testing programs shall be developed and implemented.

Measurement

M12. Generator owners/operators shall have a generator protection system maintenance and testing program in place. This program shall include protection system identification, frequency of protection system testing, and frequency of protection system maintenance.

Documentation of the program and its implementation shall be provided to the appropriate Regions and NERC on request (30 business days).

Applicable to

Generator owner/operator.

Items to be Measured

Documentation and implementation of generator protection system maintenance and testing program.

Timeframe

On request (30 business days).

Levels of Non-Compliance

Level 1
Documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.

Level 2
Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.

Level 3
Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.

Level 4
No documentation of the maintenance and testing program or its implementation was provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description Development and documentation of Regional underfrequency load shedding (UFLS) programs coordinated within and among Regions.

Category Process, data, and assessment

Section III. System Protection and Control
D. Underfrequency Load Shedding

Standards

S1. A Regional UFLS program shall be planned and implemented in coordination with other UFLS programs, if any, within the Region and, where appropriate, with neighboring Regions. The Regional UFLS program shall be coordinated with generation control and protection systems, undervoltage and other load shedding programs, Regional load restoration programs, and transmission protection and control systems.

Measure

M1. Each Region shall develop, coordinate, and document a Regional UFLS program, which shall include the following:

1. Requirements for coordination of UFLS programs within the subregions, Region, and, where appropriate, among Regions.
2. Design details shall include, but are not limited to:
   a. size of coordinated load shedding blocks (% of connected load)
   b. corresponding frequency set points
   c. intentional and total tripping time delays
   d. related generation protection
   e. tie tripping schemes
   f. islanding schemes
   g. automatic load restoration schemes
   h. any other schemes that are part of or impact the UFLS programs
3. A Regional UFLS program database. This database shall be updated as specified in the Regional program (but at least every five years) and shall include sufficient information to model the UFLS program in dynamic simulations of the interconnected transmission systems.
4. Technical assessment and documentation of the effectiveness of the design and implementation of the Regional UFLS program. This technical assessment shall be conducted periodically and shall (at least every five years or as required by changes in system conditions) include, but not be limited to:
   a. A review of the frequency set points and timing, and
   b. Dynamic simulation of possible disturbance that cause the Region or portions of the Region to experience the largest imbalance between demand (load) and generation.

Documentation of each Region's UFLS program and its database information shall be provided to NERC on request (within 30 days). Documentation of the technical assessment of the UFLS program shall also be provided to NERC on request (within 30 days).

Applicable to

Regional Reliability Councils

Items to be Measured

The documentation and coordination of Regional UFLS programs.

Timeframe

On request by NERC (within 30 days) for the program, database, and results of technical assessments.

Levels of Non-Compliance

Level 1 — Documentation demonstrating the coordination of the Regional UFLS program was incomplete in one of the requirement~~s~~ in Measure M1.

Level 2 — N/A

Level 3 — N/A

Level 4 — Documentation demonstrating the coordination of the Regional UFLS program was incomplete in two or more requirements or documentation demonstrating the coordination of the Regional UFLS program was not provided, or an assessment was not completed in the last five years.

Compliance Monitoring Responsibility

NERC

Brief Description Assuring consistency of entity UFLS programs with Regional UFLS requirements.

Category Assessment

Section III. System Protection and Control
D. Underfrequency Load Shedding

Standard

S1. A Regional UFLS program shall be planned and implemented in coordination with other UFLS programs, if any, within the Region and, where appropriate, with neighboring Regions. The Regional UFLS program shall be coordinated with generation control and protection systems, undervoltage and other load shedding programs, Regional load restoration programs, and transmission protection and control systems.

Measure

M2. Those entities owning or operating an UFLS program shall ensure that their programs are consistent with Regional UFLS program requirements as specified in Measure III.D.M1. Such entities shall provide and annually update their UFLS data as necessary for the Region to maintain and update an UFLS program as specified in Measure III.D.M1.

The documentation of an entity's UFLS program shall be provided to the Region on request (within 30 days).

Applicable to

Entities owning, operating, or required (by the Regions) to have an UFLS program.

Items to be Measured

Consistency of entity's UFLS program with Regional UFLS requirements.

Timeframe

On request (within 30 days).

Levels of Non-Compliance

Level 1 — Evaluations of entity UFLS programs for consistency with the Regional UFLS program were incomplete/inconsistent in one or more requirements of Measure III.D.M1 but is consistent with the required load shed.

Level 2 — The amount of load shedding is less than 95% of the regional requirements in any of the load steps.

Level 3 — The amount of load shedding is less than 90% of the regional requirements in any of the load steps.

Level 4 — The amount of load shedding is less than 85% of the regional requirements on any of the load steps, or evaluations of entity UFLS programs for consistency with the Regional UFLS program were not provided.

Compliance Monitoring Responsibility

Regional Reliability Councils. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Brief Description Implementation and documentation of UFLS equipment maintenance program.

Category Documentation and implementation

Section III. System Protection and Control
D. Underfrequency Load Shedding

Standard

S1. A Regional UFLS program shall be planned and implemented in coordination with other UFLS programs, if any, within the Region and, where appropriate, with neighboring Regions. The Regional UFLS program shall be coordinated with generation control and protection systems, undervoltage and other load shedding programs, Regional load restoration programs, and transmission protection and control systems.

Measure

M3. UFLS equipment owners shall have an UFLS equipment maintenance and testing program in place. This program shall include UFLS equipment identification, the schedule for UFLS equipment testing, and the schedule for UFLS equipment maintenance.

Applicable to

Entities owning, operating, or required (by Regions) to have UFLS equipment.

Items to be Measured

Documentation and implementation of UFLS equipment maintenance and testing program.

Timeframe

On request (within 30 days).

Levels of Non-Compliance

Level 1 — Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.

Level 2 — Complete documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.

Level 3 — Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.

Level 4 — Documentation of the maintenance and testing program, or its implementation was not provided.

Compliance Monitoring Responsibility

Regional Reliability Councils. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Brief Description Analysis and documentation of UFLS program performance.

Category Assessment

Section III. System Protection and Control
D. Underfrequency Load Shedding

Standard

S1. A Regional UFLS program shall be planned and implemented in coordination with other UFLS programs, if any, within the Region and, where appropriate, with neighboring Regions. The Regional UFLS program shall be coordinated with generation control and protection systems, undervoltage and other load shedding programs, Regional load restoration programs, and transmission protection and control systems.

Measurement

M4. Those entities owning or operating UFLS programs shall analyze and document their UFLS program performance in accordance with Standard III.D. S1-S2, M1, including the performance of UFLS equipment and program effectiveness following system events resulting in system frequency excursions below the initializing set points of the UFLS program. The analysis shall include, but not be limited to:

1) **A description of the event including initiating conditions**
2) **A review of the UFLS set points and tripping times**
3) **A simulation of the event**
4) **A summary of the findings**

Documentation of the analysis shall be provided to the Regions and NERC on request 90 days after the system event.

Applicable to

Entities owning, operating, or required (by the Regions) to have an UFLS program.

Items to be Measured

Analysis of UFLS program performance for underfrequency events below the UFLS set points.

Timeframe

On request 90 days after the system event.

Levels of Non-Compliance

Level 1
Analysis of UFLS program performance following an actual underfrequency event below the UFLS set point(s) was incomplete in one or more requirements of Measurement M4.

Level 2
Not applicable.

Level 3
Not applicable.

Level 4
Analysis of UFLS program performance following an actual underfrequency event below the UFLS set point(s) was not provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

III. System Protection and Control
D. Underfrequency Load Shedding

G1. The UFLS programs should occur in steps related to frequency or rate of frequency decay as determined from system simulation studies. These studies are critical to coordinate the amount of load shedding necessary to arrest frequency decay, minimize loss of load, and permit timely system restoration.

G2. The UFLS programs should be coordinated with generation protection and control, undervoltage and other load shedding programs, Regional load restoration programs, and transmission protection and control.

G3. The technical assessment of UFLS programs should include reviews of system design and dynamic simulations of disturbances that would cause the largest expected imbalances between customer demand and generation. Both peak and off-peak system demand levels should be considered. The assessments should predict voltage and power transients at a widespread number of locations as well as the rate of frequency decline, and should reflect the operation of underfrequency sensing devices. Potential system separation points and resulting system islands should be determined.

G4. Except for qualified automatic isolation plans, the opening of transmission interconnections by underfrequency relaying should be considered only after the coordinated load shedding program has failed to arrest system frequency decline and intolerable system conditions exist.

G5. A generation-deficient entity may establish an automatic islanding plan in lieu of automatic load shedding, if by doing so it removes the burden it has imposed on the transmission systems. This islanding plan may be used only if it complies with the Regional UFLS program and leaves the remaining interconnected bulk electric systems intact, in demand and generation balance, and with no unacceptable high voltages.

G6. In cases where area isolation with a large surplus of generation compared to demand can be anticipated, automatic generator tripping or other remedial measures should be considered to prevent excessive high frequency and resultant uncontrolled generator tripping and equipment damage.

G7. UFLS relay settings and the underfrequency protection of generating units as well as any other manual or automatic actions that can be expected to occur under conditions of frequency decline should be coordinated.

G8. The UFLS program should be separate, to the extent possible, from manual load shedding schemes such that the same loads are not shed by both schemes.

G9. Generator underfrequency protection should not operate until the UFLS programs have operated and failed to maintain the system frequency at an operable level. This sequence of operation is necessary both to limit the amount of load shedding required and to help the systems avoid a complete collapse. Where this sequence is not possible, UFLS programs should consider and compensate for any generator whose underfrequency protection is required to operate before a portion of the UFLS program.

G10. Plans to shed load automatically should be examined to determine if unacceptable overfrequency, overvoltage, or transmission overloads might result. Potential unacceptable conditions should be mitigated.

If overfrequency is likely, the amount of load shed should be reduced or automatic overfrequency load restoration should be provided.

If overvoltages are likely, the load shedding program should be modified (e.g., change the geographic distribution) or mitigation measures (e.g., coordinated tripping of shunt capacitors or insertion reactors) should be implemented to minimize that probability.

If transmission capabilities will likely be exceeded, the underfrequency relay settings (e.g., location, trip frequency, or time delay) should be altered or other actions taken to maintain transmission loadings within capabilities.

G11. Where the UFLS program fails to arrest frequency decline, generators may be isolated with local load to minimize loss of generation and enable timely system restoration.

Brief Description Undervoltage load shedding program documentation.

Category Documentation

Section III. System Protection and Control
E. Undervoltage Load Shedding

Standards

S1. Automatic undervoltage load shedding (UVLS) programs shall be planned and implemented in coordination with other UVLS programs in the Region and, where appropriate, with neighboring Regions.

S2. All UVLS programs shall be coordinated with generation control and protection systems, underfrequency load shedding programs, Regional load restoration programs, and transmission protection and control programs.

Measurement

M1. Those entities owning or operating UVLS programs shall document their UVLS programs including descriptions of the following design details: size of customer demand (load) blocks (% of connected load), corresponding voltage set points, relay and breaker operating times, intentional delays, related generation protection, islanding schemes, automatic load restoration schemes, or any other schemes that are part of or impact the UVLS programs.

Documentation of the UVLS programs shall be provided to the appropriate Regions and NERC on request (five business days).

Applicable to

UVLS owners and operators.

Items to be Measured

Documentation of UVLS program design details.

Timeframe

On request (five business days).

Levels of Non-Compliance

Level 1
Documentation of the UVLS program was provided, but was incomplete.

Level 2
Not applicable.

Level 3
Not applicable.

Level 4
Documentation of the UVLS program was not provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description

Undervoltage load shedding program database.

Category

Database

Section

III. System Protection and Control
E. Undervoltage Load Shedding

Standard

S1. Automatic undervoltage load shedding (UVLS) programs shall be planned and implemented in coordination with other UVLS programs in the Region and, where appropriate, with neighboring Regions.

Measurement

M2. Each Region shall maintain and annually update an UVLS program database. This database shall include sufficient information to model the UVLS program in dynamic simulations of the interconnected transmission systems, including the following items:

1) **Type of UVLS equipment,**
2) **Voltage set point(s),**
3) **Time delay from initiation to trip signal, and**
4) **Amount of demand interrupted at peak or other specified level.**

While the database shall be updated annually, the current database shall be provided to NERC on request (within 30 business days).

Applicable to

Regions.

Items to be Measured

UVLS program database.

Timeframe

Database to be updated annually.
Current database on request (30 business days).

Levels of Non-Compliance

Level 1
A UVLS program database was provided, but was incomplete.

Level 2
Not applicable.

Level 3
Not applicable.

Level 4
A UVLS program database was not provided.

Compliance Monitoring Responsibility

NERC.

Reviewer Comments on Compliance Rating

Brief Description Technical assessment of the design and effectiveness of UVLS programs.

Category Assessment

Section III. System Protection and Control
E. Undervoltage Load Shedding

Standard

S1. Automatic undervoltage load shedding (UVLS) programs shall be planned and implemented in coordination with other UVLS programs in the Region and, where appropriate, with neighboring Regions.

S2. All UVLS programs shall be coordinated with generation control and protection systems, underfrequency load shedding programs, Regional load restoration programs, and transmission protection and control programs.

Measure

M3. Those entities owning or operating UVLS programs shall periodically (at least every five years or as required by changes in system conditions) conduct and document a technical assessment of the effectiveness of their UVLS programs.

This technical assessment shall include, but is not limited to:

- Coordination of the UVLS programs with other protection and control systems in the Region and with other Regions, as appropriate.
- Simulations that demonstrate that the UVLS programs performance is consistent with the I.A Standards.
- A review of the voltage set points and timing.

Documentation of the current UVLS technical assessment shall be provided to the appropriate Regions and NERC on request (30 days).

Applicable to

UVLS owners and operators.

Items to be Measured

Technical assessment of the design and effectiveness of UVLS programs.

Timeframe

Technical assessments every five years or as required by system changes.
Current technical assessment on request (30 days).

Levels of Non-Compliance

Level 1 — N/A

Level 2 — N/A

Level 3 — N/A

Level 4 — A technical assessment of the UVLS programs did not address one of the requirements listed in M3 above or a technical assessment of the UVLS programs was not provided.

Compliance Monitoring Responsibility

Regional Reliability Councils. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Brief Description Under voltage load shedding system maintenance and testing.

Category Documentation and implementation

Section III. System Protection and Control
E. Under Voltage Load Shedding Systems

Standard

S1. Automatic undervoltage load shedding (UVLS) programs shall be planned and implemented in coordination with other UVLS programs in the Region and, where appropriate, with neighboring Regions.

Measure

M4. Under voltage load shedding system owners shall have a system maintenance and testing program(s) in place. The program(s) shall include:

a. Under voltage load shedding system identification shall include but is not limited to:
   - relays
   - instrument transformers
   - communications systems, where appropriate
   - batteries

b. Documentation of maintenance and testing intervals and their basis

c. Summary of testing procedure

d. Schedule for system testing

e. Schedule for system maintenance

f. Date last tested/maintained

Documentation of the program and its implementation shall be provided to the appropriate Regions and NERC on request (within 30 days).

Applicable to

Under voltage load shedding system owner.

Items to be Measured

Documentation and implementation of under voltage load shedding system maintenance and testing program.

Timeframe

On request (within 30 days).

Levels of Non-Compliance

Level 1 — Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.

Level 2 — Compliance documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.

Level 3 — Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.

Level 4 — Documentation of the maintenance and testing program, or its implementation, was not provided.

Compliance Monitoring Responsibility

Regional Reliability Councils. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Brief Description Analysis and documentation of UVLS program performance.

Category UVLS program performance

Section III. System Protection and Control
E. Undervoltage Load Shedding

Standard

S1. Automatic undervoltage load shedding (UVLS) programs shall be planned and implemented in coordination with other UVLS programs in the Region and, where appropriate, with neighboring Regions.

Measurement

M5. Those entities owning or operating an UVLS program shall analyze and document all UVLS operations, misoperations, and failures to operate. Documentation of the analysis shall include a review of the UVLS set points and tripping times and a summary of the findings. This documentation shall be provided to the appropriate Regions and NERC on request (30 business days).

Applicable to

UVLS owners and operators.

Items to be Measured

Analysis of UVLS program performance.

Timeframe

On request (30 business days).

Levels of Non-Compliance

Level 1
An analysis of UVLS operations, misoperations, and failures to operate was provided but was incomplete.

Level 2
Not applicable.

Level 3
Not applicable.

Level 4
An analysis of UVLS program performance was not provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description Establish and document Regional review procedures for special protection system (SPS) installations.

Category Documentation

Section III. System Protection and Control
F. Special Protection Systems

Standards

S1. An SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined under Categories A, B, or C of Table 1 of the I.A Standards on Transmission Systems.

S2. The inadvertent operation of an SPS shall meet the same performance requirement (Category A, B, or C of Table I of the I.A Standard on Transmission Systems) as that required of the contingency for which it was designed, and shall not exceed Category C.

S3. SPS installations shall be coordinated with other protection and control systems.

S4. All SPS misoperations shall be analyzed for cause and corrective action.

Measurement

M1. Each Region whose members use or are planning to use an SPS shall have a documented Regional review procedure to ensure the SPS complies with Regional criteria and NERC Planning Standards . The Regional review procedure shall include:

1) **Description of the process for submitting a proposed SPS for Regional review.**
2) **Requirements to provide data that describes design, operation, and modeling of an SPS.**
3) **Requirements to demonstrate that the SPS design will meet above SPS Standards S1 and S2.**
4) **Requirements to demonstrate the proposed SPS will coordinate with other protection and control systems and applicable Regional emergency procedures.**
5) **Regional definition of misoperation.**
6) **Requirements for analysis and documentation of corrective action plans for all SPS misoperations.**
7) **Identification of the Regional group responsible for the Region's review procedure and the process for Regional approval of the procedure.**
8) **Determination, as appropriate, of maintenance and testing requirements.**

Documentation of the Regional SPS review procedure shall be provided to affected Regions and NERC, on request (within 30 days).

Applicable to

Regions.

Items to be measured
Regional review procedure for assessing SPSs to ensure compliance with NERC Planning Standards and Regional criteria.

Timeframe
On request (within 30 days).

Levels of Non-Compliance

Level 1
Documentation of the Regional procedure is missing one of the items listed in III.F. M1.

Level 2
Documentation of the Regional procedure is missing two of the items listed in III.F. M1.

Level 3
Documentation of the Regional procedure is missing three of the items listed in III.F. M1.

Level 4
Documentation of the Regional procedure was not provided or is missing four or more of the items listed in III.F. M1.

Compliance Monitoring Responsibility
NERC.

Reviewer Comments on Compliance Rating

Brief Description Establish Regional database for SPS installations.

Category Data

Section III. System Protection and Control
F. Special Protection Systems

Standards

S1. An SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined under Categories A, B, or C of Table 1 of the I.A Standards on Transmission Systems.

S2. The inadvertent operation of an SPS shall meet the same performance requirement (Category A, B, or C of Table I of the I.A Standard on Transmission Systems) as that required of the contingency for which it was designed, and shall not exceed Category C.

S3. SPS installations shall be coordinated with other protection and control systems.

Measurement

M2. A Region that has a member with an SPS installed shall maintain an SPS database. The database shall include the following types of information:

1) Design Objectives – Contingencies and system conditions for which the SPS was designed,
2) Operation – The actions taken by the SPS in response to disturbance conditions, and
3) Modeling – Information on detection logic or relay settings that control operation of the SPS.

Documentation of the Regional database or the information therein shall be provided to affected Regions and NERC, on request (within 30 days).

Applicable to

Regions.

Items to be measured

Regional database of SPS installations.

Timeframe

On request (within 30 days).

Levels of Non-Compliance

Level 1

Regional database is missing one of the items listed in III.F. M2.

Level 2
Regional database is missing two of the items listed in III.F. M2.

Level 3
Not applicable.

Level 4
Regional database was not provided or is missing all of the elements listed in III.F. M2.

Compliance Monitoring Responsibility

NERC.

Reviewer Comments on Compliance Rating

Brief Description Regional assessment of SPS coordination and effectiveness.

Category Assessment

Section III. System Protection and Control
F. Special Protection Systems

Standards

S1. An SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined under Categories A, B, or C of Table 1 of the I.A Standards on Transmission Systems.

S2. The inadvertent operation of an SPS shall meet the same performance requirement (Category A, B, or C of Table I of the I.A Standard on Transmission Systems) as that required of the contingency for which it was designed, and shall not exceed Category C.

S3. SPS installations shall be coordinated with other protection and control systems.

Measurement

M3. A Region shall assess the operation, coordination, and effectiveness of all SPSs installed in the Region at least once every five years for compliance with NERC Planning Standards and Regional criteria. The Regions shall provide either a summary report or a detailed report of this assessment to affected Regions or NERC, on request (within 30 days). The documentation of the Regional SPS assessment shall include the following elements:

1) Identification of group conducting the assessment and the date the assessment was performed.
2) Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed.
3) Identification of SPSs that were found not to comply with NERC Planning Standards and Regional criteria.
4) Discussion of any coordination problems found between an SPS and other protection and control systems.
5) Provide corrective action plans for non-compliant SPSs.

Applicable to

Regions.

Items to be Measured

Result of Regional reviews for SPS compliance with NERC Planning Standards and Regional criteria.

Timeframe

On request (with 30 days).

Levels of Non-Compliance

Level 1
The summary (or detailed) Regional SPS assessment is missing one of the items listed in III.F. M3.

Level 2
The summary (or detailed) Regional SPS assessment is missing two of the items listed in III.F. M3.

Level 3
The summary (or detailed) Regional SPS assessment is missing three of the items listed in III.F. M3.

Level 4
The summary (or detailed) Regional SPS assessment is missing more than three of the items listed in III.F. M3 or was not provided.

Compliance Monitoring Responsibility

NERC.

Reviewer Comments on Compliance Rating

Brief Description Data for review of SPS installations.

Category Data

Section III. System Protection and Control
F. Special Protection Systems

Standard

S1. An SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined under Categories A, B, or C of Table 1 of the I.A Standards on Transmission Systems.

S2. The inadvertent operation of an SPS shall meet the same performance requirement (Category A, B, or C of Table I of the I.A Standard on Transmission Systems) as that required of the contingency for which it was designed, and shall not exceed Category C.

S3. SPS installations shall be coordinated with other protection and control systems.

Measurement

M4. SPS owners shall maintain a list of and provide data for existing and proposed SPSs as defined in Measurement III.F. S1-S3, M2. New or functionally modified SPSs shall be reviewed in accordance with the Regional procedures as defined in Measurement III.F. S1-S4, M1 prior to being placed in service.

Documentation of SPS data and the results of studies that show compliance of new or functionally modified SPSs with NERC Planning Standards and Regional criteria shall be provided to affected Regions and NERC, on request (within 30 days).

Applicable to

SPS owners.

Items to be Measured

SPS data and results of studies that show SPS compliance with NERC Planning Standards and Regional criteria.

Timeframe

On request (within 30 days).

Levels of Non-Compliance

Level 1

SPS data was provided, but was incomplete according to the Regional SPS database requirements for III.F. M2.

Level 2
Results of studies that show compliance of new or functionally modified SPSs with the NERC Planning Standards and Regional criteria were provided, but were incomplete according to the Regional procedures for III.F. M1.

Level 3
Not applicable.

Level 4
No SPS data was provided in accordance with Regional SPS database requirements for III.F. M2, or the results of studies that show compliance of new or functionally modified SPSs with the NERC Planning Standards and Regional criteria were not provided in accordance with Regional procedures for III.F. M1.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description Notification and analysis of SPS misoperations and corrective action plans.

Category Documentation

Section III. System Protection and Control
F. Special Protection Systems

Standard

S4. All SPS misoperations shall be analyzed for cause and corrective action.

Measurement

M5. SPS owners shall analyze SPS operations and maintain a record of all misoperations in accordance with Regional procedures in Measurement III.F. S1-S4, M1. Corrective actions shall be taken to avoid future misoperations.

Documentation of the misoperation analyses and the corrective action plans shall be provided to the affected Regions and NERC, on request (within 90 days).

Applicable to

SPS owners.

Items to be measured

Documentation of SPS misoperations and corrective action plans.

Timeframe

On request (within 90 days of the incident or on request (within 30 days) if requested more than 90 days after the incident).

Levels of Non-Compliance

Level 1
Documentation of SPS misoperations is complete but documentation of corrective actions taken for all identified SPS misoperations is incomplete.

Level 2
Documentation of corrective actions taken for SPS misoperations is complete but documentation of SPS misoperations is incomplete.

Level 3
Documentation of SPS misoperations and corrective actions is incomplete.

Level 4
No documentation of SPS misoperations or corrective actions was provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description Special Protection System maintenance and testing

Category Documentation and implementation

Section III. System Protection and Control
F. Special Protection Systems

Standard

S5. Special Protection System maintenance and testing programs shall be developed and implemented.

Measure

M6. Special Protection System owners shall have a system maintenance and testing program(s) in place. The program(s) shall include:

a. Special Protection System identification shall include but is not limited to:
   - relays
   - instrument transformers
   - communications systems, where appropriate
   - batteries

b. Documentation of maintenance and testing intervals and their basis

c. Summary of testing procedure

d. Schedule for system testing

e. Schedule for system maintenance

f. Date last tested/maintained

Documentation of the program and its implementation shall be provided to the appropriate Regions and NERC on request (within 30 days).

Applicable to

Special Protection System owners whose special protection systems support the reliability of the bulk power electric system.

Items to be Measured

Documentation and implementation of Special Protection System maintenance and testing program.

Timeframe

On request (within 30 days).

Levels of Non-Compliance

Level 1 — Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.

Level 2 — Complete documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.

Level 3 — Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.

Level 4 — Documentation of the maintenance and testing program, or its implementation, was not provided.

Compliance Monitoring Responsibility

Regional Reliability Councils. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

III. System Protection and Control
F. Special Protection Systems

G1. Complete redundancy should be considered in the design of an SPS with diagnostic and self-check features to detect and alarm when essential components fail or critical functions are not operational.

G2. No identifiable common mode events should result in the coincident failure of two or more SPS components.

G3. An SPS should be designed to operate only for conditions that require specific protective or control actions.

G4. As system conditions change, an SPS should be disarmed to the extent that its use is unnecessary.

G5. SPSs should be designed to minimize the likelihood of personnel error, such as incorrect operation and inadvertent disabling. Test devices or switches should be used to eliminate the necessity for removing or disconnecting wires during testing.

G6. The design of SPSs both in terms of circuitry and physical arrangement should facilitate periodic testing and maintenance. Test facilities and test procedures should be designed such that they do not compromise the independence of redundant SPS groups.

G7. SPSs that rely on circuit breakers to accomplish corrective actions should as a minimum use separate trip coils and separately fused dc control voltages.

Brief Description Establish, maintain, and document a Regional blackstart capability plan.

Category Documentation

Section IV. System Restoration
A. System Blackstart Capability

Standard

S1. A coordinated system blackstart capability plan shall be established, maintained, and verified through analysis indicating how system blackstart generating units will perform their intended functions as required in system restoration plans. Such blackstart capability plans shall include coordination within and among Regions as appropriate.

Measure

M1. Each Region shall establish and maintain a system blackstart capability plan, as part of an overall coordinated Regional system restoration plan, that shall include requirements for verification through analysis how system blackstart generating units shall perform their intended functions and shall be sufficient to meet system restoration plan expectations.

The blackstart capability plan shall include:

1. A requirement to have a database that contains all blackstart generators designated for use in a Restoration Plan within the respective areas and a requirement to update the database on an annual basis. The database shall include the name, location, MW capacity, type of unit, latest date of test, and starting method.
2. A requirement to demonstrate that blackstart units perform their intended functions as required in the Regional system restoration plan through simulation or testing. The blackstart plan must consider the availability of designated blackstart plan units and initial transmission switching requirements.
3. Blackstart unit testing requirements including, but not limited to:
   - Testing frequency (minimum of one third of the units each year).
   - Type of test required, including the requirement to start when isolated from the system
   - Minimum duration of tests
4. A requirement to review and update the Regional blackstart capability plan at least every five years.

Documentation of system blackstart capability plans shall be provided to NERC on request (30 days).

Applicable to

Regional Reliability Councils

Items to be Measured

A Regional plan for blackstart capability.

Timeframe

Current Regional blackstart capability plan: on request by NERC and other Regions (30 days).

Levels of Non-Compliance

Level 1 — N/A

Level 2 — The Region's blackstart generating unit capability plan was incomplete in one of the four requirements defined above in Measure M1.

Level 3 — N/A

Level 4 — The Region's blackstart generating unit capability plan was not provided, or incomplete in two or more of the four requirements defined above in Measure M1.

Compliance Monitoring Responsibility

NERC

Brief Description	Demonstrate through simulation or testing that a blackstart generating unit can perform its function.
Category	Simulation or testing of units
Section	IV. System Restoration A. System Blackstart Capability

Standard

S1. A coordinated system blackstart capability plan shall be established, maintained, and verified through analysis indicating how system blackstart generating units will perform their intended functions as required in system restoration plans. Such blackstart capability plans shall include coordination within and among Regions as appropriate.

Measurement

M2. Each transmission operator shall verify that the number, size, and location of system blackstart generating units are sufficient to meet Regional restoration plan expectations.

The transmission operator of each system shall demonstrate, through simulation or testing, that its blackstart generating unit(s) can perform their intended functions as required in the Regional restoration plan (Standard IV.A. S1). Such simulation or testing shall be performed at least every five years.

Documentation of the most current simulations or tests shall be provided to the Regions and NERC on request (30 business days).

Applicable to

Transmission operators.

Items to be Measured

Simulation or test results to demonstrate that blackstart generating unit(s) can perform their intended functions in system restoration.

Timeframe

Simulation or testing of blackstart capability units: every five years.
Documentation of the most current simulations or tests: on request (30 business days).

Levels of Non-Compliance

Level 1
Not applicable.

Level 2
Not applicable.

Level 3
Not applicable.

Level 4
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.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description	Diagram the number, size, and location of system blackstart generating units and the initial transmission switching requirements.
Category	Data
Section	IV. System Restoration A. System Blackstart Capability

Standard

S1. A coordinated system blackstart capability plan shall be established, maintained, and verified through analysis indicating how system blackstart generating units will perform their intended functions as required in system restoration plans. Such blackstart capability plans shall include coordination within and among Regions as appropriate.

Measurement

M3. Each transmission operator shall have on file diagrams showing the location of each blackstart generating unit that is part of the Regional blackstart capability plan (Standard IV.A. S1, M1). The diagrams shall be reviewed and updated annually or when system changes occur. Where applicable, primary and secondary cranking paths associated with each blackstart generating unit and the units to be restarted shall be identified on the diagrams. The current diagrams shall be provided to the Region and NERC on request (30 business days).

Several transmission operators or the entire Region may elect to jointly develop the diagrams to improve coordination.

Applicable to

Transmission operators.

Items to be Measured

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

Timeframe

Update of diagrams showing blackstart generating units: annually or when system changes occur.
Current diagrams: on request (30 business days).

Levels of Non-Compliance:

Level 1
Not applicable.

Level 2
Not applicable.

Level 3
Not applicable.

Level 4
The transmission operator's diagrams of the number, size, and location of system blackstart generating units and the initial transmission switching requirements were not provided, or the diagrams were not compliant with the Regional restoration plan.

Compliance Monitoring Responsibility
Regions.

Reviewer Comments on Compliance Rating

Brief Description Documentation of blackstart generating unit test results.

Category Documentation and implementation

Section IV. System Restoration
A. System Blackstart Capability

Standard

S2. Each blackstart generating unit shall be tested to verify that it can be started and operated without being connected to the system.

Measure

M4. The blackstart generating unit owner or operator shall test the startup and operation of each system blackstart generating unit identified in the blackstart capability plan as required in the regional Blackstart Plan (Standard IV.A. S1, M1). Testing records shall include the dates of the tests, the duration of the tests, and an indication of whether the tests met regional Blackstart Plan requirements. A unit cannot be considered a blackstart unit unless it has met the regional blackstart requirements. It is expected that if a unit fails a test, that unit will be fixed and retested within a timeframe established by the Region in accordance with the regional Blackstart Plan or that unit will no longer be considered blackstart.

Documentation of the test results of the startup and operation of each blackstart generating unit shall be provided to the Region and upon request to NERC.

Applicable to

Owners or operators of blackstart generating units.

Items to be Measured

Test results of the startup and operation of blackstart generating units.

Timeframe

Current test results: to the Region and upon request to NERC (30 days).

Levels of Non-Compliance

Level 1 — Startup and operation testing of each blackstart generating unit was performed but documentation was incomplete.

Level 2 — Not applicable.

Level 3 — Startup and operation testing of blackstart generating unit was only partially performed.

Level 4 — Startup and operation testing of each blackstart generating unit was not performed.

Compliance Monitoring Responsibility

Regional Reliability Councils. Each Region shall report compliance and violation to NERC via the NERC Compliance Reporting process.

Brief Description Documentation of Regional load restoration policies and programs.

Category Documentation and database

Section IV. System Protection
B. Automatic Restoration of Load

Standard

S1. Automatic load restoration programs shall be coordinated and in compliance with Regional load restoration programs. These automatic load restoration programs shall be designed to avoid recreating electric system underfrequencies or undervoltages, overloading transmission facilities, or delaying the restoration of system facilities and interconnection tie lines to neighboring systems.

Measurement

M1. A Region that has a member with an automatic load restoration system shall have a documented load restoration policy and program which include:

a. A description of how load restoration is coordinated with underfrequency and undervoltage load shedding programs within the Region and, where appropriate, among Regions.

b. Automatic load restoration design details including acceptable size of coordinated load restoration blocks (% of connected load), corresponding frequency or voltage set points, and operating sequence (including relay and breaker operating times and intentional delays).

c. Requirements for entities owning and operating automatic load restoration systems to provide on an annual basis current data for a Regional database to allow modeling the automatic load restoration programs in dynamic simulations of the interconnected transmission systems.

d. The maintenance and annual update of an automatic load restoration program database. This database shall include information to model the automatic load restoration programs in dynamic simulations of the interconnected transmission systems.

The Regional policies and programs shall conform with applicable NERC Standards and shall require programs to be designed to avoid recreating electric system underfrequencies or undervoltages, overloading transmission facilities, or delaying the restoration of system facilities and interconnection tie lines to neighboring systems.

Documentation of the Regional load restoration policy and program and a current Regional load restoration database shall be provided to other Regions and NERC on request (five business days).

Applicable to

Regions.

Items to be Measured

Documentation of Regional load restoration policy and program, and an updated Regional load restoration database.

Timeframe

Updated Regional load restoration database: annually.
Documentation of Regional policy and current database: on request (five business days).

Levels of Non-Compliance

Level 1
Documentation of the Regional load restoration policy and program was provided, but the Regional load restoration database was not updated.

Level 2
Not applicable.

Level 3
Documentation of the Regional load restoration policy and program was provided, but was incomplete in one or more elements as defined above in Measurement M1.

Level 4
Documentation of the Regional load restoration policy and program was not provided.

Compliance Monitoring Responsibility

NERC.

Reviewer Comments on Compliance Rating

Brief Description Documentation of automatic load restoration programs.

Category Documentation and data

Section IV. System Protection
B. Automatic Restoration of Load

Standard

S1. Automatic load restoration programs shall be coordinated and in compliance with Regional load restoration programs. These automatic load restoration programs shall be designed to avoid recreating electric system underfrequencies or undervoltages, overloading transmission facilities, or delaying the restoration of system facilities and interconnection tie lines to neighboring systems.

Measurement

M2. Regional members owning or operating an automatic load restoration system shall have a policy, and programs and documentation that demonstrate conformance with the Regional load restoration policy and program of Measurement IV.B. S1, M1.

Documentation of each Regional member's policy and program and its conformance to the Regional load restoration policy and program shall be provided to the Region and NERC on request (five business days).

Applicable to

Entities owning or operating automatic load restoration programs.

Items to be Measured

Documentation of Regional member's load restoration policy and programs and their conformance with the Regional load restoration policy and program as defined in IV.B. S1, M1, including coordination and data requirements.

Timeframe

On request (five business days).

Levels of Non-Compliance

Level 1
Documentation of the Regional member's automatic load restoration policy and programs was provided, but the required data was not current.

Level 2
Documentation of the Regional member's automatic load restoration policy and programs was provided, but coordination as required in the Regional policy and program (IV.B. S1, M1) was not provided or was incomplete.

Level 3
Documentation of the Regional member's automatic load restoration policy and programs was provided, but was incomplete in one of the areas required by the Regional load restoration policy and program (IV.B. S1, M1).

Level 4
Documentation of the Regional member's automatic load restoration policy and programs was not provided, or was provided but was missing two or more areas required by the Regional load restoration policy and program, or does not conform with the Regional load restoration policy and program (IV.B. S1, M1).

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description Assessment of the effectiveness of automatic load restoration programs.

Category Assessment

Section IV. System Protection
B. Automatic Restoration of Load

Standard

S1. **Automatic load restoration programs shall be coordinated and in compliance with Regional load restoration programs. These automatic load restoration programs shall be designed to avoid recreating electric system underfrequencies or undervoltages, overloading transmission facilities, or delaying the restoration of system facilities and interconnection tie lines to neighboring systems.**

Measurement

M3. **Those entities owning or operating an automatic load restoration program shall demonstrate through simulation that the design and implementation of their programs do not cause electric system underfrequencies or undervoltages, the overloading of transmission facilities, or delay in the restoration of facilities and interconnection tie lines to neighboring systems.**

Documentation of the results of the simulation of the automatic load restoration programs shall be available to the appropriate (affected) Regions and NERC on request (30 business days).

Applicable to

Entities owning or operating automatic load restoration programs.

Items to be Measured

Documentation of the simulations demonstrating that the design and implementation of the automatic load restoration programs do not cause the system impacts as described in above Measurement M3.

Timeframe

On request (30 business days).

Levels of Non-Compliance

Level 1
Not applicable.

Level 2
Not applicable.

Level 3
Not applicable.

Level 4
Documentation of the simulations of the design and implementation of the entity's automatic load restoration program was not provided, or the entity's automatic load restoration program was not operated in conformance with the Region's load restoration policy and program or the requirements of the above Measurement M3.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description Automatic load restoration equipment maintenance requirements.

Category Documentation

Section IV. System Protection
B. Automatic Restoration of Load

Standard

S1. Automatic load restoration programs shall be coordinated and in compliance with Regional load restoration programs. These automatic load restoration programs shall be designed to avoid recreating electric system underfrequencies or undervoltages, overloading transmission facilities, or delaying the restoration of system facilities and interconnection tie lines to neighboring systems.

Measurement

M4. Those entities owning or operating automatic load restoration programs shall document and implement a maintenance program that ensures accurate and reliable operation of the automatic load restoration relays.

Documentation of the implementation of the maintenance program shall be provided to the appropriate (affected) Regions and NERC on request (30 business days).

Applicable to

Entities owning or operating automatic load restoration programs.

Items to be Measured

Documentation of the maintenance program and its implementation.

Timeframe

On request (30 business days).

Levels of Non-Compliance

Level 1
Documentation of the implementation of the automatic load restoration maintenance program was complete, but the maintenance program documentation was incomplete.

Level 2
Not applicable.

Level 3
Documentation of the maintenance program and its implementation for the automatic load restoration system was not available, but maintenance is being performed.

Level 4
Documentation of the maintenance program and its implementation for the automatic load restoration system was not available, and maintenance was not being performed.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating