NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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

Assess Transmission Future Needs & Develop Transmission Plans

SAR Drafting Team Meeting

February 3–4, 2004
Tampa, Florida

AGENDA

I. Administrative

(a) NERC Antitrust Compliance Guidelines (Attachment A)
(b) Roster Update (Attachment B)
(c) Arrangements

II. SAR Process Overview — Maureen Long, NERC Staff

(a) SAR drafting team deliverable
(b) SAR process overview (NERC Reliability Standards Process Manual)
(c) Timeline
(d) Drafting team governance — Paul Rocha

III. General Discussion of Transmission Assessment and Planning Issues

(a) Is existing standard a good starting point for new standard? (Attachments C to E)
(b) Should probabilistic criteria be allowed? If so, can each planning authority independently set its own assessment and planning criteria?
(c) To what extent, if any, should transmission assessment/planning standard address assessment of voltage stability and planning of reactive resource additions?
(d) To what extent, if any, should standard address non-reliability aspects of transmission assessment and planning, such as:

  (i) Cost-effectiveness of transmission plans
  (ii) Minimization of landowner impact
  (iii) Market facilitation (minimization of congestion costs and RMR)

(e) What should be required to demonstrate compliance to standard?

IV. Changes to Initial SAR (Attachment F)**, Responses to Comments About Initial SAR, and Draft Summary of SAR Comments** (Attachment G)

V. Next Steps

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NERC ANTITRUST COMPLIANCE GUIDELINES

I. GENERAL

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

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

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

II. PROHIBITED ACTIVITIES

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

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.

- Discussions of a participant's marketing strategies.

- Discussions regarding how customers and geographical areas are to be divided among competitors.

- Discussions concerning the exclusion of competitors from markets.

- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

Approved by NERC Board of Trustees
June 14, 2002

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III. ACTIVITIES THAT ARE PERMITTED

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

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

- Organization Standards Process Manual
- Transitional Process for Revising Existing NERC Operating Policies and Planning Standards
- Organization and Procedures Manual for the NERC Standing Committees
- System Operator Certification Program

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

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

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

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

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

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

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

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

Attachment B

SAR Drafting Team Roster
Assess Transmission Future Needs & Develop Transmission Plans

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Introduction

The fundamental purpose of the interconnected transmission systems is to move electric power from areas of generation to areas of customer demand (load). These systems should be capable of performing this function under a wide variety of expected system conditions (e.g., forced and planned equipment outages, continuously varying customer demands) while continuing to operate reliably within equipment and electric system thermal, voltage, and stability limits.

Electric systems must be planned to withstand the more probable forced and planned outage system contingencies at projected customer demand and projected electricity transfer levels.

Extreme but less probable contingencies measure the robustness of the electric systems and should be evaluated for risks and consequences. The risks and consequences of these contingencies should be reviewed by the entities responsible for the reliability of the interconnected transmission systems. Actions to mitigate or eliminate the risks and consequences are at the discretion of those entities.

The ability of the interconnected transmission systems to withstand probable and extreme contingencies must be determined by simulated testing of the systems as prescribed in these I.A. Standards on Transmission Systems.

System simulations and associated assessments are needed periodically to ensure that reliable systems are developed with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future system needs.

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.

Measurement

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) and summarized below:

a. Line and equipment loadings shall be within applicable thermal rating limits.
b. Voltage levels shall be maintained within applicable limits.
c. All customer demands shall be supplied, and all projected firm (non-recallable reserved) transfers shall be maintained.
d. Stability of the network shall be maintained.

Assessment Requirements

Entities responsible for the reliability of interconnected transmission systems (e.g., transmission owners, independent system operators (ISOs), regional transmission organizations (RTOs), or other groups responsible for planning the bulk electric systems) shall annually assess the performance of their systems in meeting Standard S1.

Valid assessments shall include the attributes listed below, and as more fully described in the following paragraphs:

1. **Be supported by a current or past study that addresses the plan year being assessed.**
2. **Address any planned upgrades needed to meet the performance requirements of Category A.**
3. **Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.**

System performance assessments based on system simulation testing shall show that with all planned facilities in service (no contingencies), established normal (pre-contingency) operating procedures in place, and with all projected firm transfers modeled, line and

equipment loadings are within applicable thermal ratings, voltages are within applicable limits, and the systems are stable for selected demand levels over the range of forecast system demands.

Assessments shall include the effects of existing and planned reactive power resources to ensure that adequate reactive resources are available to meet the system performance as defined in Category A of Table I.

Assessments shall be conducted annually and shall cover critical system conditions and study years as deemed appropriate by the responsible entity. They shall be conducted for near- (years one through five) and longer-term (years six through ten) planning horizons. Simulation testing of the systems need not be conducted annually if changes to system conditions do not warrant such analyses. Simulation testing beyond the five-year horizon should be conducted as needed to address identified marginal conditions that may have longer lead-time solutions.

Corrective Plan Requirements

When system simulations indicate an inability of the systems to respond as prescribed in this Measurement (M1), responsible entities shall provide a written summary of their plans, including a schedule for implementation, to achieve the required system performance throughout the planning horizon as described above. Plan summaries shall discuss expected required in-service dates of facilities, and shall consider lead times necessary to implement plans. Identified system facilities for which sufficient lead times exist need not have detailed implementation plans, and shall be reviewed for continuing need in subsequent annual assessments.

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 summary (per Standard I.B. S1. M1) of its Regional reliability assessments to the NERC Planning Committee (or its successor).

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

Not applicable.

Level 2

A valid assessment for the longer-term planning horizon is not available.

Level 3
Not applicable.

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

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

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).

Measurement

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) and summarized below:

a. Line and equipment loadings shall be within applicable rating limits.
b. Voltage levels shall be maintained within applicable limits.
c. No loss of customer demand (except as noted in Table I, footnote b) shall occur, and no projected firm (non-recallable reserved) transfers shall be curtailed.
d. Stability of the network shall be maintained.
e. Cascading outages shall not occur.

Assessment Requirements

Entities responsible for the reliability of interconnected transmission systems (e.g., transmission owners, independent system operators (ISOs), regional transmission organizations (RTOs), or other groups responsible for planning the bulk electric systems) shall annually assess the performance of their systems in meeting Standard S2. Valid assessments shall include the attributes listed below, and as more fully described in the following paragraphs:

1. **Assessments shall be supported by a current or past study that addresses the plan year being assessed.**

2. **Assessments shall address any planned upgrades needed to meet the performance requirements of Category B.**

3. **Assessments shall be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.**

System performance assessments based on system simulation testing shall show that for system conditions where the initiating event results in the loss of a single generator, transmission circuit, or bulk system transformer, and with all projected firm transfers modeled, line and equipment loadings are within applicable thermal ratings, voltages are within applicable limits, and the systems are stable for selected demand levels over the range of forecast system demands. No planned loss of customer demand nor curtailment of projected firm transfers shall be necessary to meet these performance requirements, except as noted in footnote b of Table I. This system performance shall be achieved for the described contingencies of Category B of Table I.

Assessments shall consider all contingencies applicable to Category B, but shall simulate and evaluate only those that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining simulations would produce less severe system results.

Assessments shall include the effects of existing and planned facilities, including reactive power resources to ensure that adequate reactive resources are available to meet the system performance as defined in Category B of Table I. Assessments shall also include the effects of existing and planned protection systems and control devices, including any backup or redundant protection systems, to ensure that protection systems and control devices are sufficient to meet the system performance as defined in Category B of Table I.

The systems must be capable of meeting Category B requirements while accommodating 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.

Assessments shall be conducted annually and shall cover critical system conditions and study years as deemed appropriate by the responsible entity. They shall also be conducted for near- (years one through five) and longer-term (years six through ten) planning horizons. Simulation testing of the systems need not be conducted annually if changes to system conditions do not warrant such analyses. Simulation testing beyond the five-year horizon should be conducted as needed to address identified marginal conditions that may have longer lead-time solutions.

Corrective Plan Requirements

When system simulations indicate an inability of the systems to respond as prescribed in this Measurement (M2), responsible entities shall provide a written summary of their plans, including a schedule for implementation, to achieve the required system performance throughout the planning horizon as described above. Plan summaries shall discuss expected required in-service dates of facilities, and shall consider lead times necessary to implement plans. Identified system facilities for which sufficient lead times exist need not have detailed implementation plans, and shall be reviewed for continuing need in subsequent annual assessments.

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 summary (per Standard I.B. S1. M1) of its Regional reliability assessments to the NERC Planning Committee (or its successor).

Applicable to
Entities responsible for reliability of interconnected transmission systems.

Items to be Measured
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
Not applicable.

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

Level 3
Not applicable.

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

Compliance Monitoring Responsibility
Regions.

Reviewer Comments on Compliance Rating

I. System Adequacy and Security
A. Transmission Systems

G1. The planning, development, and maintenance of transmission facilities should be coordinated with neighboring systems to preserve the reliability benefits of interconnected operations.

G2. Studies affecting more than one system owner or user should be conducted on a joint interconnected system basis.

G3. The interconnected transmission systems should be designed and operated such that reasonable and foreseeable contingencies do not result in the loss or unintentional separation of a major portion of the network.

G4. The interconnected transmission systems should provide flexibility in switching arrangements, voltage control, and other protection system measures to ensure reliable system operation.

G5. The assessment of transmission system capability and the need for system enhancements should take into account maintenance outage plans of the transmission facility owners. These maintenance plans should be coordinated on an intra- and interregional basis.

G6. The interconnected transmission systems should be planned to avoid excessive dependence on any one transmission circuit, structure, right-of-way, or substation.

G7. Extreme contingency evaluations should be conducted to measure the robustness of the interconnected transmission systems and to maintain a state of preparedness to deal effectively with such events. Although it is not practical (and in some cases not possible) to construct a system to withstand all possible extreme contingencies without cascading, it is desirable to control or limit the scope of such cascading or system instability events and the significant economic and social impacts that can result.

G8. Extreme contingency assessments should be conducted on a coordinated intra- or interregional basis so that all potentially affected entities are aware of the possibility of cascading or system instability events.

Table I. Transmission Systems Standards — Normal and Contingency Conditions

Category	Contingencies		System Limits or Impacts				
	Initiating Event(s) and Contingency Element(s)	Elements Out of Service	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

Categories A and B - Approved by Planning Committee February 27, 2001, and NERC Board of Trustees June 12, 2001.
Category C - Approved by Planning Committee November 15, 2001, the Market Interface Committee January 10, 2002, and NERC Board of Trustees February 20, 2002.
Category D - Approved by Planning Committee September 27, 2001, and NERC Board of Trustees October 16. 2001.

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 3. Transformer 2. Transmission Circuit 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) for an event or 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.

Categories A and B - Approved by Planning Committee February 27, 2001, and NERC Board of Trustees June 12, 2001.
Category C - Approved by Planning Committee November 15, 2001, the Market Interface Committee January 10, 2002, and NERC Board of Trustees February 20, 2002.
Category D - Approved by Planning Committee September 27, 2001, and NERC Board of Trustees October 16. 2001.

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 conditions of the contingencies 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 conditions of the contingencies as defined in Category C of Table I (attached).

Measurement

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

a. **Line and equipment loadings shall be within applicable thermal rating limits.**
b. **Voltage levels shall be maintained within applicable limits.**
c. **Planned (controlled) interruption of customer demand or generation (as noted in Table I, footnote d) may occur, and contracted firm (non-recallable reserved) transfers may be curtailed.**
d. **Stability of the network shall be maintained.**
e. **Cascading outages shall not occur.**

Assessment Requirements

Entities responsible for the reliability of the interconnected transmission systems (e.g., transmission owners, independent system operators (ISOs), regional transmission organizations (RTOs), or other groups responsible for planning the bulk electric systems) shall annually assess the performance of their systems in meeting Standard S3.

Valid assessments shall include the attributes listed below, and as more fully described in the following paragraphs:

1. **Assessments shall be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.**

2. **Assessments of the near-term planning horizon shall be supported by a current or past study that addresses the plan year being assessed. For assessments of the longer-term planning horizon, a current or past study that addresses the plan year being assessed shall only be required if marginal conditions that may have longer lead-time solutions have been identified in the near-term assessment.**

3. **Assessments shall address any planned upgrades needed to meet the performance requirements of Category C.**

System performance assessments based on system simulation testing shall show that for system conditions where (See Table I Category C)

1. **The initiating event results in the loss of two or more elements, or**
2. **Two separate events occur resulting in two or more elements out of service with time for manual system adjustments between events,**

and with all projected firm transfers modeled, line and equipment loadings are within applicable thermal ratings, voltages are within applicable limits, and the systems are stable for selected demand levels over the range of forecast system demands. Planned outages of customer demand or generation (as noted in Table I, footnote d) may occur, and contracted firm (non-recallable reserved) transfers may be curtailed. This system performance shall be achieved for the described contingencies of Category C of Table I.

Assessments shall consider all contingencies applicable to Category C, but shall simulate and evaluate only those that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining simulations would produce less severe system results.

Assessments shall include the effects of existing and planned facilities, including reactive power resources to ensure that adequate reactive resources are available to meet the system performance as defined in Category C of Table I. Assessments shall also include the effects of existing and planned protection systems and control devices, including any backup or redundant protection systems, to ensure that protection systems and control devices are sufficient to meet the system performance as defined in Category C of Table I.

The systems must be capable of meeting Category C requirements while accommodating 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.

Assessments shall be conducted annually and shall cover critical system conditions and study years as deemed appropriate by the responsible entity. They shall also be conducted for near (years one through five) and longer-term (years six through ten) planning horizons. Simulation testing of the systems need not be conducted annually if changes to system conditions do not warrant such analyses. Simulation testing beyond the five-year horizon should be conducted as needed to address identified marginal conditions that may have longer lead-time solutions.

Corrective Plan Requirements
When system simulations indicate an inability of the systems to respond as prescribed in this Measurement (M3), responsible entities shall provide a written summary of their plans, including a schedule for implementation, to achieve the required system performance throughout the planning horizon as described above. Plan summaries shall discuss expected required in-service dates of facilities, and shall consider lead times necessary to implement plans. Identified system facilities for which sufficient lead times exist need not have detailed implementation plans, and shall be reviewed for continuing need in subsequent annual assessments.

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 summary (per Standard I.B. S1. M1) of its Regional reliability assessments to the NERC Planning Committee (or its successor).

Applicable to
Entities responsible for the reliability of interconnected transmission systems.

Items to be Measured
Assessments of system performance for events resulting in the 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 for the longer-term planning horizon is not available.

Level 2
Not applicable.

Level 3
A valid assessment for the near-term planning horizon is not available.

Level 4
Not applicable.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Table I. Transmission Systems Standards — Normal and Contingency Conditions

Category	Contingencies		System Limits or Impacts				
	Initiating Event(s) and Contingency Element(s)	Elements Out of Service	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

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Categories A and B - Approved by Planning Committee February 27, 2001, and NERC Board of Trustees June 12, 2001.
Category C - Approved by Planning Committee November 15, 2001, the Market Interface Committee January 10, 2002, and NERC Board of Trustees February 20, 2002.
Category D - Approved by Planning Committee September 27, 2001, and NERC Board of Trustees October 16. 2001.

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 3. Transformer 2. Transmission Circuit 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) for an event or 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.

Categories A and B - Approved by Planning Committee February 27, 2001, and NERC Board of Trustees June 12, 2001.
Category C - Approved by Planning Committee November 15, 2001, the Market Interface Committee January 10, 2002, and NERC Board of Trustees February 20, 2002.
Category D - Approved by Planning Committee September 27, 2001, and NERC Board of Trustees October 16. 2001.

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).

Measurement

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 the interconnected transmission systems (e.g., transmission owners, independent system operators (ISOs), regional transmission organizations (RTOs), or other groups responsible for planning the bulk electric systems) shall annually assess the performance of their systems in meeting Standard S4.

Valid assessments shall include the attributes listed below, and as more fully described in the following paragraphs:

1. **Assessments shall be conducted for near-term (years one through five) planning horizons.**

2. **Assessments shall be supported by a current or past study that addresses the plan year being assessed.**

System performance assessments based on system simulation testing shall evaluate system conditions of Table I Category D, with all projected firm transfers modeled.

Assessments shall consider all contingencies applicable to Category D, but shall simulate and evaluate only those that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining simulations would produce less severe system results.

Assessments shall include the effects of existing and planned facilities, including reactive power resources, and shall include the effects of existing and planned protection systems and control devices, including any backup or redundant protection systems.

Assessments shall consider 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 when evaluating the effects of Category D events.

Assessments shall be conducted annually and shall cover critical system conditions and study years as deemed appropriate by the responsible entity. They shall be conducted for near-term (years one through five) planning horizons. Simulation testing of the systems need not be conducted annually if changes to system conditions do not warrant such analyses.

Corrective Plan Requirements
None required.

Reporting Requirements
The documentation of results of these reliability assessments and mitigation measures shall annually be provided to the entities' respective NERC Region(s), as required by the Region. Each Region, in turn, shall annually provide a summary (per Standard I.B. S1. M1) of its Regional reliability assessments to the NERC Planning Committee (or its successor).

Applicable to
Entities responsible for the reliability of interconnected transmission systems.

Items to be Measured
Assessments of system performance for extreme events (more severe than in M3) resulting in loss of two or more bulk system elements.

Timeframe
Annually.

Levels of Non-Compliance
Level 1
A valid assessment for the near-term planning horizon is not available.

Level 2
Not applicable.

Level 3
Not applicable.

Level 4
Not applicable.

Compliance Monitoring Responsibility
Regions.

Comments on Compliance Rating

I. System Adequacy and Security
A. Transmission Systems

G1. The planning, development, and maintenance of transmission facilities should be coordinated with neighboring systems to preserve the reliability benefits of interconnected operations.

G2. Studies affecting more than one system owner or user should be conducted on a joint interconnected system basis.

G3. The interconnected transmission systems should be designed and operated such that reasonable and foreseeable contingencies do not result in the loss or unintentional separation of a major portion of the network.

G4. The interconnected transmission systems should provide flexibility in switching arrangements, voltage control, and other protection system measures to ensure reliable system operation.

G5. The assessment of transmission system capability and the need for system enhancements should take into account the maintenance outage plans of the transmission facility owners. These maintenance plans should be coordinated on an intra- and interregional basis.

G6. The interconnected transmission systems should be planned to avoid excessive dependence on any one transmission circuit, structure, right-of-way, or substation.

G7. Reliability assessments should examine post-contingency steady-state conditions as well as stability, overload, cascading, and voltage collapse conditions. Pre-contingency system conditions chosen for analysis should include contracted firm (non-recallable reserved) transmission services.

G8. Annual updates to the transmission assessments should be performed, as appropriate, to reflect anticipated significant changes in system conditions.

G9. Extreme contingency evaluations should be conducted to measure the robustness of the interconnected transmission systems and to maintain a state of preparedness to deal effectively with such events. Although it is not practical (and in some cases not possible) to construct a system to withstand all possible extreme contingencies without cascading, it is desirable to control or limit the scope of such cascading or system instability events and the significant economic and social impacts that can result.

G10. It may be appropriate to conduct the extreme contingency assessments on a coordinated intra- or interregional basis so that all potentially affected entities are aware of the possibility of cascading or system instability events.

Table I. Transmission Systems Standards — Normal and Contingency Conditions

Category	Contingencies		System Limits or Impacts				
	Initiating Event(s) and Contingency Element(s)	Elements Out of Service	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

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Category D - Approved by Planning Committee September 27, 2001, and NERC Board of Trustees October 16. 2001.

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 3. Transformer 2. Transmission Circuit 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) for an event or 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.

Categories A and B - Approved by Planning Committee February 27, 2001, and NERC Board of Trustees June 12, 2001.
Category C - Approved by Planning Committee November 15, 2001, the Market Interface Committee January 10, 2002, and NERC Board of Trustees February 20, 2002.
Category D - Approved by Planning Committee September 27, 2001, and NERC Board of Trustees October 16. 2001.

Introduction

NERC, through its Planning Committee (or successor group(s)), reviews and assesses the overall reliability (adequacy and security) of the interconnected bulk electric systems, both existing and as planned, to ensure that each Region (subregion) complies with the NERC Planning Standards and its own Regional planning criteria.

NERC also conducts special reliability assessments on a Regional, interregional, and Interconnection basis as conditions warrant or as requested by the NERC Planning Committee or Board of Trustees. Such special reliability assessments may include, among others, 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, and 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.

To carry out these reviews and assessments of the overall reliability of the interconnected bulk electric systems, NERC (and its Planning Committee or successor group(s)) must have sufficient data and input from the Regions to prepare and publish NERC's annual seasonal (summer and winter) and longer-range assessments of the reliability of the interconnected bulk electric systems. Additional data may also be required for the special reliability assessments.

NERC's adequacy and security assessments must ensure the requirements stated in each Region's planning criteria and the NERC Planning Standards are met.

The Regions must also assess their Regional bulk electric system reliability within the context of the interconnected networks. Therefore, the Region and it members must coordinate their assessment efforts not only within their Region, but also with neighboring systems and Regions.

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.

Measurement

M1. Each Region shall annually conduct reliability assessments of its respective existing and planned Regional bulk electric system (generation and transmission facilities) for: 1) seasonal (winter and summer of the current year) conditions or other current-year system conditions as deemed appropriate by the Region, and 2) near-term (years one through five) and longer-term (years six through ten) planning horizons. For the near term, detailed assessments shall be conducted. For the longer term, assessment shall focus on the analysis of trends in resources and transmission adequacy, other industry trends and developments, and reliability concerns.

Similarly, the Regions shall also annually conduct interregional reliability assessments to ensure that the Regional bulk electric systems are planned and developed on a coordinated or joint basis to preserve the adequacy and security of the interconnected bulk electric systems.

Regional and interregional reliability assessments shall demonstrate that the performance of these systems are 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, among others, 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, and 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

Regions.

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.

Timeframe
Annually or as requested.

Levels of Non-Compliance
Level 1
Regional, interregional, and/or special reliability assessments were provided as requested, but were incomplete.

Level 2
Not applicable.

Level 3
Not applicable.

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

Compliance Monitoring Responsibility
NERC.

Reviewer Comments on Compliance Rating

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

Introduction

Sufficient reactive resources must be located throughout the electric systems, with a balance between static and dynamic characteristics. Both static and dynamic reactive power resources are needed to supply the reactive power requirements of customer demands and the reactive power losses in the transmission and distribution systems, and provide adequate system voltage support and control. They are also necessary to avoid voltage instability and widespread system collapse in the event of certain contingencies. Transmission systems cannot perform their intended functions without an adequate reactive power supply.

Dynamic reactive power support and voltage control are essential during power system disturbances. Synchronous generators, synchronous condensers, and static var compensators (SVCs and STATCOMs) can provide dynamic support. Transmission line charging and series and shunt capacitors are also sources of reactive support, but are static sources.

Reactive power sources must be distributed throughout the electric systems among the generation, transmission, and distribution facilities, as well as at some customer locations. Because customer reactive demands and facility loadings are constantly changing, coordination of distribution and transmission reactive power is required. Unlike active or real power (MWs), reactive power (Mvars) cannot be transmitted over long distances and must be supplied locally.

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.

Standard Authorization Request (SAR) Form

Title of Proposed Standard:	Assess Transmission Future Needs and Develop Transmission Plans
Request Date:	March 6, 2002
Authorized for Posting:	March 20, 2002
SAR ID# :	TRNS_NDS_&_PLNS_01_01

SAR Requestor Information		**SAR Type** (Put an 'x' in front of one of these selections)	
Name:	Jim Byrd	X	New Standard
Primary Contact:	Jim Byrd		Revision to existing Standard
Telephone: Fax:	214-743-6870 972-263-6710		Withdrawal of existing Standard
e-mail:	jbyrd@txu.com		Emergency Action

Purpose/Industry Need (Provide one or two sentences)

To establish a standard for assessing and planning the transmission systems in North America.
The transmission system must be assessed and planned to ensure that it performs its intended functions in providing reliable delivery of power for the future needs of customers.

Brief Description (A few sentences or a paragraph)

Requirements shall be established for assessing transmission system performance under a variety of system conditions including system normal conditions, abnormal conditions, and extreme system conditions. Requirements shall be established for a plan, including a definition of the planning horizon, to address these conditions to ensure that the interconnected transmission systems perform their intended functions and to prevent severe adverse effects such as uncontrolled or cascading interruption of network operation. The plan may utilize operating, construction, market solutions or other components to address these conditions.

Reliability Functions

The Standard will Apply to the Following Functions *(Put an 'X' in front of each one that applies)*		
X	Reliability Authority	Ensures the reliability of the bulk transmission system within its Security Authority Area. This is the highest reliability authority.
	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time
	Interchange Authority	Authorizes valid and balanced Interchange Schedules
X	Planning Authority	Plans the bulk electric system
	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
X	Transmission Owner	Owns transmission facilities
	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
	Distribution Provider	Provides and operates the "wires" between the transmission system and the customer
	Generator	Owns and operates generation unit(s) or runs a market for generation products that performs the functions of supplying energy and Interconnected Operations Services
	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required.
	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

Reliability and Market Interface Principles

Applicable Reliability Principles *(Put an 'x in front of all that apply)*	
X	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions.
	2. The frequency of interconnected bulk electric systems shall be controlled within defined limits through the balancing of electric supply and demand
X	3. Information necessary for planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably
	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented
	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems
X	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions
X	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis

Does the proposed Standard comply with all of the following Market Interface Principles? *(Enter 'yes' or 'no')*	YES
1. Interconnected The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy	
2. An Organization Standard shall not give any market participant an unfair competitive advantage	
3. An Organization Standard shall neither mandate nor prohibit any specific market structure	
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard	
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards	

Attachment G

SAR – Assess Transmission Future Needs and Develop Transmission Plans

Brief Summary of Comments Received

Development of this SAR is not needed or is premature.

There must be coordination with development of a “commercial” standard and all commercial implications should be identified before drafting this SAR.
No work should be done on this SAR until FERC specifies the organization responsible for wholesale electric standards development.
Present standards are adequate. Do not need a new set of standards. At the very least, the present standards should be used as starting points for the new standards. Development should rely heavily on the existing NERC reliability criteria.
This SAR is not a “Core Reliability” organization standard. Regional processes already exist for assessing and planning the power system.
Entire standard should be eliminated. The SAR should be developed as only a “practice” to be used in the certification process for Planning Authorities and Reliability Authorities.
Not enough information provided in the SAR to determine if it is needed or not.
Every RTO will have or already has a planning protocol on how long term transmission plans are developed.

Scope of this SAR should be limited.

Scope should be reduced to eliminate any aspect that goes beyond establishing specific reliability criteria.
Standard should not go beyond assessment and planning of the bulk transmission system.
Standard should not apply to intrastate systems.
Scope for transmission planning should not include market solutions as permanent solutions. Market solutions should only be used as interim solutions.
Market solutions are outside NERC’s scope with respect to development of reliability policies.
Standard should focus only upon required performance objective, rather than prescribing the means to achieve the objective.
Broad performance-based criteria standards should be developed. Do not need standards on “how” to assess or plan systems. Current standards focus too much on the “how”.
Definition of “what” core reliability standards are needed is encouraged. However, “how” they are achieved and implemented should not be included at this time until there is clarity on SMD and RTO formation and NERC/NAESB interface is defined.
SAR should only address creation of Planning Standards. Plan Development is a compliance issue.
SAR should only define the reliability requirements, not specific solutions.
Eliminate the function related to “assessing” transmission performance. Only “plan” future transmission expansion.
Standard should only apply to long-term planning function. Should be a parallel standard for operational planning.
Standard must not become a mandate for all to use the same load flow model.

Scope of this SAR should be expanded or include the following.

Scope should be expanded to include generation as well.
NERC should guard against establishing a one-dimensional standard that fails to take into account all dimensions that guide the planning process.
SAR should include a requirement to plan the system so that it can be operated within operating limits.
Scope should include planning associated with IPPs.
NERC should ensure that the standards defined include a definition of how the planning model is created.

Standard should be specific and measurable and define what “normal”, “extreme”, and “abnormal” system conditions are.
Minimum set of criteria for assessing acceptability of plans is needed.
May be a need for multiple and expansion plans because of timing of generator projects that are dictated by commercial rather than system adequacy considerations.
Must define what minimum need is. Some regulatory backstop is needed if expansion plans are deemed insufficient to meet needs.
SAR should identify who has obligation to implement transmission plans.
Must use a reasonable planning horizon (< or = 5 years).
Provision for interim use of RAP and SPS is needed.
Regional differences should be recognized.
Requirement to provide assessment at all demand levels should be added.
Responsibility for assessing and defining adequate operating reserves and reactive support should be added.
Planning criteria should be expanded to include maintainability of the system.
When studies indicate that system may not meet performance requirements, plans should be developed to address the situation and studies should demonstrate that implemented plans meet requirements.
Core standard for reliability should be specific and measurable.

Miscellaneous Comments.

Technical specifications should ensure that they do not prohibit worthwhile commercial negotiations or commercial activity.
Must have coordination with operating procedures and protocols of RTOs.
Must be close coordination with NAESB and RTOs to meet both reliability objectives and commercial needs.
Measuring for compliance is extremely difficult. It is also difficult to determine if events will result in “cascading” outages.
SAR will not accomplish its intent without credible models from which to do analysis.
SAR seems large – divide it up?
Scope of SAR is poorly written. It does not convey transmission planning responsibilities.
Separate SAR should be established for implementation of SPS. Develop plans to address operational issues for interconnected grids where SPS is needed to mitigate against system deficiencies.
SAR does not set standard, but tries to assign responsibility for setting standard.

There were numerous comments concerning which reliability functions to which the SAR should apply. As written, the SAR applies to the following Reliability Functions:

Reliability Authority
Planning Authority
Transmission Owner

It was suggested that these Reliability Functions be added:

Generator
Transmission Operator
Distribution Provider
Transmission Service Provider
Purchasing-Selling Entity
Load-Serving Entity

It was also suggested that these Reliability Functions be excluded:

Transmission Owner
Reliability Authority