Standard Development Roadmap

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Description of Current Draft:

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Future Development Plan:

Anticipated Actions	Anticipated Date
1. Seek endorsement of NERC technical committees.	November 9–11, 2004
2. First ballot of Version 0 standards.	December 1–10, 2004
3. Recirculation ballot of Version 0 standards.	December 27, 2004 – January 7, 2005
4. 30-day posting before board adoption.	January 8, 2005 – February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **System Performance Assessments Under Normal (No Contingency) Conditions (Category A)**

2. **Number:** TPL-001-0 (051.1)

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned 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~~ 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 defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner ~~valid~~ assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses ~~all~~ each of the ~~elements in the~~ following ~~list~~categories, ~~as accepted by the Regional Reliability Organization,~~ showing system performance following Category A of Table 1 (no contingencies). ~~that addresses the plan year being assessed.~~ The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. D~~For identified system facilities for which sufficient lead times exist, review in subsequent annual assessments for continuing need — d~~etailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment ~~provide evidence to its Compliance Monitor that it provided Assessments~~ and corrective plans ~~for the system responses per~~as specified in Reliability Standard TPL-001-0_R3_1 and TPL-001-0_R3-2.

M2. The Planning Authority and Transmission Planner shall ~~provide~~ have evidence ~~to its Compliance Monitor that~~ it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility
Compliance Monitor: Regional Reliability Organization.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe
Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

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

2.3. **Level 3:** Not applicable.

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

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading~~[e]~~ Outages
A No Contingencies	All Facilities in Service	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	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 8. Transformer 7. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 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 Reliability Organization.	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 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 Reliability 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~~c) 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.

d) 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.

e) 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, and not because of an intentional design delay.

f) 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.

Standard Development Roadmap

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

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Description of Current Draft:

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Future Development Plan:

Anticipated Actions	Anticipated Date
1. Seek endorsement of NERC technical committees.	November 9–11, 2004
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4. 30-day posting before board adoption.	January 8, 2005 – February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. Title: **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. Number: TPL-002-0 (051.2)

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

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Proposed Effective Date: April 1~~February 8~~, 2005

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned 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. To be valid, ~~T~~the Planning Authority and Transmission Planner ~~valid~~ assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories,~~all of the elements in the following list~~, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets ~~Table 1 for~~ Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. 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.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1, the Planning ~~Authorities~~ Authority and Transmission Planner~~s responsible for planning the Bulk Electric System~~ shall each:

R2.1. Provide a written summary of ~~their~~ its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. D~~For identified system facilities for which sufficient lead times exist, review in subsequent annual assessments for continuing need — d~~etailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment ~~provide evidence to its Compliance Monitor that it provided Assessments~~ and corrective plans as specified in~~for the System responses per~~ Reliability Standard TPL-002-0_R1 and TPL-002-0_R2.

M2. The Planning Authority and Transmission Planner shall have ~~provide~~ evidence ~~to its Compliance Monitor that~~ it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-0_R3.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: Regional Reliability Organizations.
   Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

   1.2. Compliance Monitoring Period and Reset Timeframe

   Annually.

   1.3. Data Retention

   None specified.

   1.4. Additional Compliance Information

   None.

2. **Levels of Non-Compliance**

   2.1. Level 1: Not applicable.

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

   2.3. Level 3: Not applicable.

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

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	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.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 8. Transformer 7. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section - - - - - - - - - - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - - - - - - - - - - 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 Reliability Organization.	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 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 Reliability 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) 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.

d) 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.

e) 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, and not because of an intentional design delay.

f) 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.

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4. 30-day posting before board adoption.	January 8, 2005 – February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-0 (051.3)

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned 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 may be necessary to meet this standard. To be valid, t~~T~~he Planning Authority and Transmission Planner ~~valid~~ assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses ~~all~~ each of the ~~elements~~ following categories, ~~in the following list as accepted by the Regional Reliability Organization,~~ showing system performance following Category ~~A~~ C of Table 1 (~~no~~ multiple contingencies) ~~that addresses the plan year being assessed~~. The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. 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.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0_R1, the Planning Authority and Transmission Planner ~~responsible for planning the Bulk Electric System~~ shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. ~~For identified System facilities for which sufficient lead times exist, review in subsequent annual Assessments for continuing need — d~~Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment ~~provide evidence to its Compliance Monitor that it provided Assessments~~ and corrective plans as specified in ~~for the System responses per~~ Reliability Standard TPL-003-0_R1 and TPL-003-0_R2.

M2. The Planning Authority and Transmission Planner shall ~~provide~~ have evidence ~~to its Compliance Monitor that~~ it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

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

2.3. Level 3: Not applicable.

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

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	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.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 8. Transformer 7. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 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 Reliability Organization.	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 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 Reliability 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~~c) 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.

d) 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.

e 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, and not because of an intentional design delay.

f) 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.

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4. 30-day posting before board adoption.	January 8, 2005–February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. **Number**: TPL-004-0 (051.4)

3. **Purpose**: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability**:

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. ~~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.~~ To be valid, t~~T~~he Planning Authority's and Transmission Planner's ~~valid~~ assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses ~~all~~ each of the following categories ~~elements in the following list, as accepted by the Regional Reliability Organization~~, showing system performance following Category D contingencies of Table I. ~~that addresses the plan year being assessed.~~ The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. 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.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment ~~provide Assessments to its Compliance Monitor~~ for its system responses as specified in~~per~~ Reliability Standard TPL-004-0_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-0_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

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

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

~~E.~~B. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [e] Outages
A No Contingencies	All Facilities in Service	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.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 8. Transformer 7. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 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 Reliability Organization.	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 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 Reliability 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~~c) 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.

d) 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.

e) 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, and not because of an intentional design delay.

f) 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.

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Future Development Plan:

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1. Seek endorsement of NERC technical committees.	November 9-11, 2004
2. First ballot of Version 0 standards.	December 1-10, 2004
3. Recirculation ballot of Version 0 standards.	December 27, 2004–January 7, 2005
4. 30-day posting before board adoption.	January 8, 2005–February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Regional and Interregional Self-Assessment Reliability Reports**

2. **Number:** TPL-005-0 (052.1)

3. **Purpose:** To ensure that each Regional Reliability Organization complies with planning criteria, for assessing the overall reliability (Adequacy and Security) of the interconnected Bulk Electric Systems, both existing and as planned.

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization shall annually conduct reliability assessments of its respective existing and planned Regional Bulk Electric System (generation and transmission facilities) for:

R1.1. Current year:

R1.1.1. Winter.

R1.1.2. Summer.

R1.1.3. Other system conditions as deemed appropriate by the Regional Reliability Organization.

R1.2. Near-term planning horizons (years one through five). D~~d~~etailed assessments shall be conducted.

R1.3. 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.

R1.4. Inter-Regional reliability assessments to ~~ensure that the Regional Bulk Electric Systems are planned and developed on a coordinated or joint basis. The Regional Reliability Organization's Regional and Interregional Reliability Assessments shall~~ demonstrate that the performance of these systems is in compliance with NERC Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0, TPL-004-0 and respective Regional transmission and generation criteria. These assessments shall also identify key reliability issues and the risks and uncertainties affecting Adequacy and Security.

R2. The Regional Reliability Organization shall provide its Regional and Inter-Regional seasonal, near-term, and longer-term reliability assessments ~~shall~~ to NERC on an annual basis.

R3. The Regional Reliability Organization shall perform special reliability assessments as requested by NERC or the NERC Board of Trustees under their specific directions and criteria. Such assessments may include, but are not limited to:

R3.1. Security assessments.

R3.2. Operational assessments.

R3.3. Evaluations of emergency response preparedness.

R3.4. Adequacy of fuel supply and hydro conditions.

R3.5. Reliability impacts of new or proposed environmental rules and regulations.

R3.6. 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.

C. Measures

M1. The Regional Reliability Organization shall provide evidence to its Compliance Monitor that annual Regional and Inter-Regional assessments of reliability for seasonal, near-term, and longer-term planning horizons, and special assessments, were developed and provided as requested by other Regional Reliability Organizations or NERC.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: ~~Unaffiliated Third Party~~NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Regional, Inter-Regional, and/or special reliability assessments were provided as requested, but were incomplete.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Regional, Inter-Regional, and/or special reliability assessments were not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title: Data From the Regional Reliability Organization Needed to Assess Reliability**

2. **Number:** TPL-006-0 (052.2)

3. **Purpose:** To ensure that each Regional Reliability Organization complies with planning criteria, for assessing the overall reliability (Adequacy and Security) of the interconnected Bulk Electric Systems, both existing and as planned.

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization 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 Reliability 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:

R1.1. Electric Demand and Net Energy for Load (actual and projected ~~Demands~~ demands and Net Energy for Load, forecast methodologies, forecast assumptions and uncertainties, and treatment of Demand-Side Management.)

R1.2. Resource Adequacy and supporting ~~Information~~ information (Regional assessment reports, existing and planned resource data, resource availability and characteristics, and fuel types and requirements.)

R1.3. Demand-Side resources and their characteristics (program ratings, effects on annual system ~~Loads~~ loads and ~~Load~~ load shapes, contractual arrangements, and program durations.)

R1.4. Supply-~~Side~~ side resources and their characteristics (existing and planned generator units, Ratings, performance characteristics, fuel types and availability, and real and reactive capabilities.)

R1.5. Transmission system and supporting information (thermal, voltage, and Stability Limits, contingency analyses, system restoration, system modeling and data requirements, and protection systems.)

R1.6. System operations and supporting information (extreme weather impacts, Interchange Transactions, and Congestion impacts on the reliability of the interconnected Bulk Electric Systems.)

R1.7. Environmental and regulatory issues and impacts (air and water quality issues, and impacts of existing, new, and proposed regulations and legislation.)

Measures

M2. The Regional Reliability Organization shall provide evidence to its Compliance Monitor that it provided Regional system data, reports, and system performance information per Reliability Standard TPL-006-0_R1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: ~~Unaffiliated Third Party~~NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Requested Regional system data, reports, or system performance information were incomplete.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

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

D. Regional Differences

1. None identified.

Version History

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Standard Development Roadmap

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A. Introduction

1. **Title:** **Facility Connection Requirements**

2. **Number:** FAC-001-0 (053.1)

3. **Purpose:** To avoid adverse impacts on reliability, ~~Generator Owners and~~ Transmission Owners ~~and electricity end-users~~ must ~~meet~~ establish facility connection and performance requirements.

4. **Applicability:**

   4.1. Transmission Owner

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. The Transmission Owner shall document, maintain, and publish facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Reliability Organization, subregional, Power Pool, and individual Transmission Owner planning criteria and facility connection requirements. The Transmission Owner's facility connection requirements shall address connection requirements for:

R1.1. Generation facilities,

R1.2. Transmission facilities, and

R1.3. End-user facilities

~~to ensure compliance with NERC Reliability Standards and applicable Regional Reliability Organization, Sub Regional, Power Pool, and individual Transmission Owner Planning Criteria and facility connection requirements.~~

R2. The Transmission Owner's facility connection requirements shall address, but are not limited to, the following items:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems.

R2.1.2. Procedures for notification of new or modified facilities to others (those responsible for the reliability of the interconnected transmission systems) as soon as feasible.

R2.1.3. Voltage level and MW and MVAR capacity or demand at point of connection.

R2.1.4. Breaker duty and surge protection.

R2.1.5. System protection and coordination.

R2.1.6. Metering and telecommunications.

R2.1.7. Grounding and safety issues.

R2.1.8. Insulation and insulation coordination.

R2.1.9. Voltage, Reactive Power, and power factor control.

R2.1.10. Power quality impacts.

R2.1.11. Equipment Ratings.

R2.1.12. Synchronizing of facilities.

R2.1.13. Maintenance coordination.

R2.1.14. Operational issues (abnormal frequency and voltages).

R2.1.15. Inspection requirements for existing or new facilities.

R2.1.16. Communications and procedures during normal and emergency operating conditions.

R3. The Transmission Owner shall maintain and update its facility connection requirements as required. The Transmission Owner shall make documentation of these requirements available to the users of the transmission system~~s~~, the Regional Reliability Organization, and NERC on request (five business days).

C. Measures

M1. The Transmission Owner shall make available (to its Compliance Monitor) for inspection evidence that it met all the requirements stated in Reliability Standard FAC-001-0_R1. ~~for Generation facilities, Transmission facilities, and end-user facilities.~~

M2. The Transmission Owner shall make available (to its Compliance Monitor) for inspection evidence that ~~they~~ it met all ~~16~~ requirements stated in Reliability Standard FAC-001-0_R2. ~~for Generation facilities, Transmission facilities, and end-user facilities.~~

M3. The Transmission Owner shall make available (to its Compliance Monitor) for inspection evidence that it met all the requirements stated in Reliability Standard FAC-001-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (five business days).

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Facility connection requirements were provided for generation, transmission, and end-user facilities, per Reliability Standard FAC-001-0_R1, but the document(s) do not address all of the requirements of Reliability Standard FAC-001-0_R2.

2.2. Level 2: Facility connection requirements were not provided for all three categories (generation, transmission, or end-user) of facilities, per Reliability Standard FAC-001-0_R1, but the document(s) provided address all of the requirements of Reliability Standard FAC-001-0_R2.

2.3. Level 3: Facility connection requirements were not provided for all three categories (generation, transmission, or end-user) of facilities, per Reliability Standard FAC-001-0_R1, and the document(s) provided do not address all of the requirements of Reliability Standard FAC-001-0_R2.

2.4. Level 4: No document on facility connection requirements was provided per Reliability Standard FAC-001-0_R3.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title: Coordination of Plans For New Generation, Transmission, and End-User Facilities**

2. **Number:** FAC-002-0 (053.2)

3. **Purpose:** To avoid adverse impacts on reliability, Generator Owners and Transmission Owners and electricity end-users must meet facility connection and performance requirements.

4. **Applicability:**

   4.1. Generator Owner

   4.2. Transmission Owner

   4.3. Distribution Provider

   4.4. Load-Serving Entity

   4.5. Transmission Planner

   4.6. Planning Authority

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. The Generator Owner, Transmission Owner, Distribution Provider, ~~or~~ and Load-Serving Entity seeking to integrate generation facilities, transmission facilities, and electricity end-user facilities shall each coordinate and cooperate on ~~their~~ its ~~respective~~ assessments with its Transmission Planner and Planning Authority. ~~to evaluate the Reliability impact of the new facilities and their connections on the Interconnected Transmission Systems.~~ The assessment shall include:

R1.1. Evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems.

R1.2. Ensurance of compliance with NERC Reliability Standards and applicable Regional, subregional, Power Pool, and individual system planning criteria and facility connection requirements.

R1.3. Evidence that the parties involved in the assessment have coordinated and 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.

R1.4. Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance in accordance with Reliability Standard TPL-001-0.

R1.5. Documentation that the assessment included study assumptions, system performance, alternatives considered, and jointly coordinated recommendations.

R2. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each retain its documentation (of its evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems) for three years and shall provide the documentation to the Regional Reliability ~~Council~~ Organization(s) Regional Reliability Organization(s) and NERC on request (within 30 calendar days).

C. Measures

M1. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider's documentation of its assessment of the reliability impacts of new facilities shall address all items in Reliability Standard FAC-002-0_R1.

M2. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each have evidence of its assessment of the reliability impacts of new facilities and their connections on the interconnected transmission systems is retained and provided to other entities in accordance with Reliability Standard FAC-002-0_R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: RRO.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days).

1.3. Data Retention

Evidence of the assessment of the reliability impacts of new facilities and their connections on the interconnected transmission systems: Three years.

1.4. Additional Compliance Information

None

2. Levels of Non-Compliance

2.1. Level 1: Assessments of the impacts of new facilities were provided, but were incomplete in one or more requirements of Reliability Standard FAC-002_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

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

E. Regional Differences

1. None identified.

Version History

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6. Effective date.	April 1, 2005

Introduction

1. **Title:** **Documentation of Total Transfer Capability and Available Transfer Capability Calculation Methodologies**

2. **Number:** MOD-001-0 (054.1)

3. **Purpose:** To promote the consistent and uniform application of Transfer Capability calculations among transmission system users, the Regional Reliability Organization shall develop methodologies for calculating Total Transfer Capability (TTC) and Available Transfer Capability (ATC) that comply with NERC definitions for TTC and ATC, NERC Reliability Standards, and applicable Regional criteria. ~~Methodologies and resulting values shall be made available to all participants of the electricity market. (To ensure that methodologies and resulting values are available to all participants in the electricity market.)~~

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization, 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.) The Regional Reliability Organization's TTC and ATC methodology shall include each of the following nine items, and shall explain its use in determining TTC and ATC values:

R1.1. A narrative explaining how TTC and ATC values are determined.

R1.2. An accounting for how the reservations and schedules for firm (non-recallable) and non-firm (recallable) transfers, both within and outside the Transmission Service Provider's ~~System~~system, are included.

R1.3. An accounting for the ultimate points of power injection (sources) and power extraction (sinks) in TTC and ATC calculations.

R1.4. A description of 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~~ because the reservations have not all been made.)

R1.5. A requirement that TTC and ATC values shall be determined and posted as follows:

R5.1.1. Daily values for current week at least once per day~~,~~.

R5.1.2. Daily values for day 8 through the first month at least once per week~~,~~.

R5.1.3. Monthly values for months 2 through 13 at least once per month.

R1.6. Indication of ~~that~~ the treatment and level of customer demands, including interruptible demands.

R1.7. A ~~S~~specification of how system conditions, limiting facilities, contingencies, transmission reservations, energy schedules, and other data needed by Transmission Service Providers for the calculation of TTC and ATC values are shared and used within the Regional Reliability Organization and with neighboring interconnected electric systems, including adjacent systems, subregions, and Regional Reliability

Organizations. 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.

R1.8. A description of how the assumptions for and the calculations of TTC and ATC values change over different time (such as hourly, daily, and monthly) horizons.

R1.9. A description of the Regional Reliability Organization's practice on the netting of transmission reservations for purposes of TTC and ATC determination.

R2. The Regional Reliability Organization shall make the most recent version of the documentation of its TTC and ATC methodology available on a web site accessible by NERC, the Regional Reliability Organizations, and ~~the~~ transmission users ~~in the electricity market~~.

C. Measures

M1. The Regional Reliability Organization shall provide evidence that its most recent TTC and ATC methodology documentation meets Reliability Standard MOD-001-0_R1.

M2. The Regional Reliability Organization shall provide evidence that its TTC and ATC methodology is available on a web site accessible by NERC, the Regional Reliability Organizations, and ~~the~~ transmission users. ~~in the electricity market.~~

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: ~~Unaffiliated Third Party~~NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

Available on a website accessible by NERC, the Regional Reliability Organizations, and transmission users.

1.3. Data Retention

None identified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: The Regional Reliability Organization's documented TTC and ATC methodology does not address one or two of the nine items required for documentation under Reliability Standard MOD-001-0_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: The Regional Reliability Organization's documented TTC and ATC methodology does not address three or more of the nine items required for documentation under Reliability Standard MOD-001-0_R1 or the Regional Reliability Organization does not have a documented TTC and ATC methodology available on a web site in accordance with Reliability Standard MOD-001-0_R2.

E. Regional Differences

1. None identified.

Version History

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6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Review of Transmission Service Provider Total Transfer Capability and Available Transfer Capability Calculations and Results**

2. **Number:** MOD-002-0 (054.2)

3. **Purpose:** To promote the consistent and uniform application of transfer capability calculations among ~~transmission system users~~Transmission Service Providers, the Regional Reliability Organizations ~~(RROs)~~ ~~shall~~need to ~~develop~~ review adherence to Regional methodologies for calculating Total Transfer Capability (TTC) and Available Transfer Capability (ATC).

4. ~~Methodologies and resulting values shall be made available to all participants of the electricity market. (To ensure that methodologies and resulting values are available to all participants in the electricity market.)~~**Applicability:**

   4.1. Regional Reliability Organizations

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and implement a procedure to periodically review (at least annually) and ensure that the TTC and ATC calculations and resulting values of member Transmission Service Providers comply with the Regional TTC and ATC methodology and applicable Regional criteria.

R2. Each Regional Reliability Organization shall document the results of its periodic reviews of TTC and ATC.

R3. The Regional Reliability Organization shall provide the results of its most current reviews of TTC and ATC to NERC on request (within 30 calendar days).

C. Measures

M1. The Regional Reliability Organization's written procedure for the performance of periodic reviews of Regional TTC and ATC calculations shall comply with Reliability Standard MOD-002-0_R1.

M2. The Regional Reliability Organization shall have evidence that it provided documentation of the results of its periodic reviews of TTC and ATC to NERC within 30 calendar days.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: ~~Unaffiliated Third Party~~NERC.

   1.2. Compliance Monitoring Period and Reset Timeframe

   Procedure on Request (within 30 calendar days).

   Documentation provided by NERC on request (within 30 calendar days).

   1.3. Data Retention

   None specified.

   1.4. Additional Compliance Information

None.

2. **Levels of Non-Compliance**

   2.1. **Level 1:** Not applicable.

   2.2. **Level 2:** The Regional Reliability Organization did not perform an annual review of all Transmission Service Providers within its Region for consistency with its TTC and ATC methodology. ~~on an annual basis.~~

   2.3. **Level 3:** Not applicable.

   2.4. **Level 4:** The Regional Reliability Organization does not have a procedure for performing a TTC and ATC methodology consistency review of all Transmission Service Providers within its Regional Reliability Organization, or has not performed ~~any~~ such annual reviews. ~~on an annual basis.~~

E. Regional Differences

1. None identified.

Version History

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A. Introduction

1. **Title:** **Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values**

2. **Number:** MOD-003-0 (054.3)

3. **Purpose:** To promote the consistent and uniform application of Transfer Capability ~~calculations C~~calculations ~~(TTC)~~ among Transmission Service Providers~~System Users~~, the Regional Reliability Organizations need to review adherence to Regional ~~shall develop~~ methodologies for calculating Total Transfer Capability (TTC) and Available Transfer Capability (ATC). ~~that comply with NERC definitions for Total Transfer Capability and Available Transfer Capability, the NERC Reliability Standards, and applicable Regional criteria. Methodologies and resulting values shall be made available to all participants of the electricity market. (To ensure that methodologies and resulting values are available to all participants in the electricity market.)~~

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization, 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 Service Provider(s), and how these concerns or questions will be addressed. The Regional Reliability Organization's procedure shall specify the following:

R1.1. The name, telephone number and email address of a contact person to whom concerns are to be addressed.

R1.2. The amount of time it will take for a response.

R1.3. The manner in which the response will be communicated (e.g., email, letter, telephone, etc~~.~~).

R1.4. What recourse a customer has if the response is deemed unsatisfactory.

R2. The Regional Reliability Organization shall post on a web site that is accessible by the Regional Reliability Organizations, NERC, and ~~the~~ transmission users ~~in the electricity market~~, its procedure ~~which addresses~~for receiving and addressing concerns about the TTC and ATC methodology and TTC and ATC values of member Transmission Service Providers.

C. Measures

M1. The Regional Reliability Organization shall have evidence that its procedure for receiving input for ATC and TTC methodologies and values meets Reliability Standard MOD-003-0_R1.

M2. The Regional Reliability Organization shall have evidence that its procedure for receiving input for ATC and TTC methodologies and values is available on a web site accessible by the Regional Reliability Organizations, NERC, and transmission users.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: ~~Unaffiliated Third Party~~NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

Procedure available on a web site accessible by the Regional Reliability Organizations, NERC, and transmission users.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: The Regional Reliability Organization does not have a procedure available on an accessible web site, or the procedure does not incorporate all required elements of Reliability Standard MOD-003-0_R1.

2.3. Level 3: Not applicable.

2.4. Level 4: The Regional Reliability Organization has no procedure available.

E. Regional Differences

1. None identified.

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A. Introduction

1. **Title:** **Documentation of Regional Reliability Organization Capacity Benefit Margin Methodologies**

2. **Number:** MOD-004-0 (055.1)

3. **Purpose:** To promote the consistent and uniform application of transmission Transfer Capability margins calculations, Capacity Benefit Margin (CBM) must be calculated in a consistent manner.

4. ~~To promote the consistent and uniform application of Transfer Capability Margin calculations among Transmission System Users,~~ **Applicability:**

   4.1. Regional Reliability Organization

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and document a Regional CBM methodology. The Regional Reliability Organization's CBM methodology shall include each of the following ten items, and shall explain its use in determining CBM value. Other items that are Regional Reliability Organization specific or that are considered in each respective Regional Reliability Organization methodology shall also be explained along with their use in determining CBM values.

R1.1. Specify that the method used by each Regional Reliability Organization member to determine its generation reliability requirements as the basis for CBM shall be consistent with its generation planning criteria.

R1.2. Specify the frequency of calculation of the generation reliability requirement and associated CBM values.

R1.3. Require that generation unit outages considered in a Transmission Service Provider's CBM calculation be restricted to those units within the Transmission Service Provider's system.

R1.4. Require that CBM be preserved only on the Transmission Service Provider's System where the Load-Serving Entity's Load is located (i.e., CBM is an import quantity only).

R1.5. Describe the inclusion or exclusion rationale for generation resources of each Load-Serving Entity including those generation resources not directly connected to the Transmission Service Provider's system but serving Load-Serving Entity ~~Loads~~ loads connected to the Transmission Service Provider's system.

R1.6. Describe the inclusion or exclusion rationale for generation connected to the Transmission Service Provider's system but not obligated to serve Native/Network Load connected to the Transmission Service Provider's system.

R1.7. Describe the formal process and rationale for the Regional Reliability Organization to grant any variances to individual Transmission Service Providers from the Regional Reliability Organization's CBM methodology.

R1.8. 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.

R1.9. Describe the inclusion or exclusion rationale for the ~~Loads~~ loads of each Load-Serving Entity, including interruptible ~~Demands~~ 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).

R1.10. Describe the inclusion or exclusion rationale for generation reserve sharing arrangements in the CBM values.

R2. The Regional Reliability Organization shall make the most recent version of the documentation of its CBM methodology available on a web-site accessible by NERC, the Regional Reliability Organizations, and ~~the~~ transmission users. ~~in the electricity market.~~

C. Measures

M1. The Regional Reliability Organization's most recent CBM methodology documentation shall meet Reliability Standard MOD-004-0_R1.

M2. The Regional Reliability Organization's CBM methodology shall be available on a web-site accessible by NERC, the Regional Reliability Organizations, and ~~the~~ transmission users. ~~in the electricity market.~~

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: ~~Unaffiliated Third Party~~NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

The most recent version of CBM methodology documentation ~~A~~available on a website accessible by NERC, the Regional Reliability Organizations, and transmission users.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: The Regional Reliability Organization's documented CBM methodology does not address one or two of the ten items required for documentation under Reliability Standard MOD-004-0_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: The Regional Reliability Organization's documented CBM methodology does not address three or more of the ten items required for documentation under Reliability Standard MOD-004-0_R1, or the Regional Reliability Organization does not have a documented CBM methodology available on a web-site in accordance with Reliability Standard MOD-004-0_R2.

E. Regional Differences

1. None identified.

Version History

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A. Introduction

1. **Title:** **Procedure for Verifying Capacity Benefit Margin Values**

2. **Number:** MOD-005-0 (055.2)

~~3.~~**Purpose:** To ~~promote the consistent and uniform application of Transfer Capability Margin calculations among Transmission System Users, by developing methodologies for calculating Capacity Benefit Margin (CBM). This methodology shall comply with NERC definitions for Capacity Benefit Margin, the NERC Reliability Standards, and applicable Regional criteria. Regional Capacity Benefit Margin methodologies and the resulting Capacity Benefit Margin values shall be available to all participants of the electricity market, in order to facilitate intra- and inter-Regional Transactions.~~

3. promote the consistent and uniform application of Transfer Capability calculations among transmission system users, the Regional Reliability Organizations need to review adherence to Regional methodologies for calculating Capacity Benefit Margin (CBM).

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and implement a procedure to review (at least annually) the CBM calculations and the resulting values of member Transmission Service Providers to ensure that they comply with the Regional Reliability Organization's CBM methodology. The procedure shall include the following four requirements:

R1.1. Indicate the frequency under which the verification review shall be implemented.

R1.2. 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.

R1.3. Require review of the consistency of the Transmission Service Provider's CBM components with its published planning criteria. A CBM value is considered consistent with published planning criteria if the components that comprise CBM are 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 Available Transfer Capability determinations are often time constrained and thus will not permit the use of the same mechanics employed in the more rigorous Planning process.~~

R1.4. Require CBM values to be periodically updated (at least annually) and available to the Regional Reliability Organizations, NERC, and transmission users~~ in the electricity markets~~.

R2. Each Regional Reliability Organization shall document its CBM procedure and shall make its~~document the results of its periodic~~ CBM review ~~reviews~~procedure ~~and shall make the results~~ available to NERC on request (within 30 calendar days).

R3. The Regional Reliability Organization shall provide documentation of the results of the most current implementation of its CBM review procedure to NERC on request (within 30 calendar days).

C. Measures

M1. The Regional Reliability Organization's written procedure for the performance of periodic reviews of Regional CBM calculations shall comply with Reliability Standard MOD-005_R1.

M2. The Regional Reliability Organization shall have documentation of the results of its periodic reviews of CBM calculations, in accordance with Reliability Standard MOD-005-0_R2 and MOD-005-0_R3.

M3. The Regional Reliability Organization shall have evidence that it provided documentation of its CBM review procedure and the results of the most current implementation of the procedure to NERC as requested (within 30 calendar days).

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: ~~Unaffiliated Third Party~~NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

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

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: The Regional Reliability Organization did not perform an annual review of all Transmission Service Providers within its Region~~al Reliability Organization~~ for consistency with the ~~Regional Reliability Organization's~~Regional CBM methodology. ~~on an annual basis.~~

2.3. Level 3: Not applicable.

2.4. Level 4: The Regional Reliability Organization does not have a procedure for performing a CBM methodology consistency review of all Transmission Service Providers within its Region~~al Reliability Organization~~, or has not performed any ~~such~~ annual reviews~~ on an annual basis~~.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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

Development Steps Completed:

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Description of Current Draft:

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Future Development Plan:

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1. Seek endorsement of NERC technical committees.	November 9–11, 2004
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3. Recirculation ballot of Version 0 standards.	December 27, 2004–January 7, 2005
4. 30-day posting before board adoption.	January 8, 2005–February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Procedures for the Use of Capacity Benefit Margin Values**

2. **Number:** MOD-006-0 (055.3)

~~3.~~**Purpose:** To ~~promote the consistent and uniform application of Transfer Capability Margin calculations among Transmission System Users, by developing methodologies for calculating Capacity Benefit Margin (CBM). This methodology shall comply with NERC definitions for Capacity Benefit Margin, the NERC Reliability Standards, and applicable Regional criteria. Regional Capacity Benefit Margin methodologies and the resulting Capacity Benefit Margin values shall be available to all participants of the electricity market, in order to facilitate intra- and inter-Regional Transactions.~~

3. promote the consistent and uniform use of transmission Transfer Capability margins calculations among transmission system users,

4. **Applicability:**

   4.1. Transmission Service Provider

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. Each Transmission Service Provider shall document ~~a~~ its procedure on the use of Capacity Benefit Margin (CBM) (scheduling of energy against a CBM preservation). The procedure~~,~~ ~~which~~ shall include the following three components:

R1.1. 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.

R1.2. Require that CBM shall only be used if the Load-Serving Entity calling for its use is experiencing a generation deficiency and its Transmission Service Provider is also experiencing Transmission Constraints relative to imports of energy on its transmission system.

R1.3. Describe the conditions under which CBM may be available as Non-Firm Transmission Service.

R2. Each Transmission Service Provider shall make ~~their~~ its CBM use procedure available on a web site accessible by the Regional Reliability Organizations, NERC, and ~~the~~ transmission users ~~in the electricity market~~..

C. Measures

M1. The Transmission Service Provider's procedure for the use of CBM (scheduling of energy against a CBM preservation) shall meet Reliability Standard MOD-006-0_R1.

M2. The Transmission Service Provider's procedure for the use of CBM (scheduling of energy against a CBM preservation) shall be available on a web site accessible by the Regional Reliability Organizations, NERC, and ~~the~~ transmission users ~~in the electricity market~~.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. **Compliance Monitoring Responsibility**

   Compliance Monitor: Regional Reliability Organizations

   1.2. **Compliance Monitoring Period and Reset Timeframe**

   Each Regional Reliability Organization shall report compliance and violations to NERC via the NERC ~~Compliance~~ compliance ~~Reporting~~ reporting process.

   1.3. **Data Retention**

   None specified.

   1.4. **Additional Compliance Information**

   None.

2. **Levels of Non-Compliance**

   2.1. **Level 1:** The Transmission Service Provider's procedure for use of CBM ~~use procedure~~ is available and addresses only two of the three requirements for such documentation as listed above under Reliability Standard MOD-006-0_R1.

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

   2.3. **Level 3:** Not applicable.

   2.4. **Level 4:** The Transmission Service Provider's procedure for use of CBM ~~use procedure~~ addresses one or none of the three requirements as listed above under Reliability Standard MOD-006-0_R1, or is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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4. 30-day posting before board adoption.	January 8, 2005–February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Documentation of the Use of Capacity Benefit Margin**

2. **Number:** MOD-007-0 (055.4)

3. **Purpose:** To promote the consistent and uniform application of Transfer Capability margin calculations among transmission system users by developing methodologies for calculating Capacity Benefit Margin (CBM). This methodology shall comply with NERC definitions for CBM, the NERC Reliability Standards, and applicable Regional criteria. ~~Regional methodologies and the resulting values shall be available to all participants of the electricity market, in order to facilitate intra- and inter-Regional transactions.~~

4. **Applicability:**

   4.1. Transmission Service Provider

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. Each Transmission Service Provider that uses CBM shall report (to the Regional Reliability Organization, 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. (~~The~~ This use of CBM shall be consistent with the Transmission Service Provider's procedure for use of CBM.)

R2. The Transmission Service Provider shall post the following three items within 15 calendar days after the use of CBM for an Energy ~~e~~Emergency. ~~purposes~~ This posting shall be on a web site accessible by the Regional Reliability Organizations, NERC, and ~~the~~ transmission users ~~in the electricity market~~.

R2.1. Circumstances.

R2.2. Duration.

R2.3. Amount of CBM used.

C. Measures

M1. The Transmission Service Provider shall have evidence that it posted an after-the-fact disclosure that energy was scheduled against a CBM preservation (for purposes other than Non-Firm Transmission Sales) on a website accessible by the Regional Reliability Organizations, NERC, and ~~the~~ transmission users ~~in the electricity market~~.

M2. If the Transmission Service Provider had energy scheduled against a CBM preservation (for purposes other than Non-Firm Transmission Sales) the Transmission Service Provider shall have evidence it posted an after-the-fact disclosure that includes the elements required by Reliability Standard MOD-007_R2.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: Regional Reliability Organizations.

   1.2. Compliance Monitoring Period and Reset Timeframe

   Within 15 calendar days of the use of CBM (excluding Non-Firm Transmission Sales)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. 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 Regional Reliability Organizations, NERC, and transmission users ~~in the electricity market~~, or meets only two of the three requirements as listed in Reliability Standard MOD-007-0_R2.

2.3. Level 3: Not applicable.

2.4. Level 4: After the use of CBM (excluding Non-Firm Transmission Sales), information pertaining to the use of CBM was provided but meets one or none of the three requirements as listed above under Reliability Standard MOD-007-0_R2, or no information was provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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4. 30-day posting before board adoption.	January 8, 2005–February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Documentation and Content of Each Regional Transmission Reliability Margin Methodology**

2. **Number:** MOD-008-0 (056.1)

3. **Purpose:** ~~To promote the consistent application of Transfer Capability margin calculations among Transmission System Providers and Transmission Owners, by developing methodologies for calculating Transmission Reliability Margin. This methodology shall comply with NERC definitions for Transmission Reliability Margin, the NERC Reliability Standards, and applicable Regional criteria. Regional Transmission Reliability Margin methodologies and the resulting Transmission Reliability Margin values shall be available to all participants of the electricity market, in order to facilitate intra- and inter-regional Transmission Service.~~To promote the consistent application of transmission Transfer Capability margin calculations among Transmission ~~System~~Service Providers and Transmission Owners, each Regional Reliability Organization shall develop a methodology for calculating Transmission Reliability Margin (TRM). This methodology shall comply with the NERC definition for TRM, the NERC Reliability Standards, and applicable Regional criteria.

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and document a Regional TRM methodology. The Region's TRM methodology shall specify or describe each of the following five items, and shall explain its use, if any, in determining TRM values. Other items that are Region~~al~~-specific or that are considered in each respective Regional methodology shall also be explained along with their use in determining TRM values.

R1.1. Specify the update frequency of TRM calculations.

R1.2. Specify how TRM values are incorporated into Available Transfer Capability calculations.

R1.3. Specify the uncertainties accounted for in TRM and the methods used to determine their impacts on the TRM values. Any component of uncertainty, other than those identified in MOD-008-0_R1.3.1 through MOD-008-0_R1.3.7, shall benefit the interconnected transmission systems as a whole before they shall be permitted to be included in TRM calculations. The components of uncertainty identified in MOD-008-0_R1.3.1 through MOD-008-0_R1.3.7, if applied, shall be accounted for solely in TRM and not ~~Capacity Benefit Margin~~CBM.

R1.3.1. Aggregate Load forecast error (not included in determining generation reliability requirements~~),~~).

R1.3.2. Load distribution error~~,~~.

R1.3.3. Variations in facility Loadings due to balancing of generation within a ~~Control~~ Balancing Authority Area~~,~~.

R1.3.4. Forecast uncertainty in transmission system topology~~,~~.

R1.3.5. Allowances for parallel path (loop flow) impacts~~,~~.

R1.3.6. Allowances for simultaneous path interactions~~,~~.

R1.3.7. Variations in generation dispatch~~, ~~.~~and~~

R1.3.8. Short-term System 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 Transmission Reliability Margin calculations.~~

R1.4. Describe the conditions, if any, under which TRM may be available to the market as Non-Firm Transmission Service.

R1.5. Describe the formal process for the Regional Reliability Organization to grant any variances to individual Transmission Service Providers from the Regional TRM methodology.

R2. The Regional Reliability Organization shall make its most recent version of the documentation of its TRM methodology available on a web site accessible by NERC, the Regional Reliability Organizations, and ~~the~~ transmission users~~ in the electricity market~~.

C. Measures

M1. The Regional Reliability Organization’s most recent version of the documentation of its TRM methodology is available on a website accessible by NERC, the Regional Reliability Organizations, and ~~the~~ transmission users.

M2. The Regional Reliability Organization’s most recent version of the documentation of its TRM contains all items in Reliability Standard MOD-008-0_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: ~~Unaffiliated Third Party.~~NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

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

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: The Regional Reliability Organization’s documented TRM methodology does not address one of the five items required for documentation under Reliability Standard MOD-008-0_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: The Regional Reliability Organization's documented TRM methodology does not address two or more of the five items required for documentation under Reliability Standard MOD-008-0_R1.

Or

The Regional Reliability Organization does not have a documented TRM methodology.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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4. 30-day posting before board adoption.	January 8, 2005–February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Procedure for Verifying Transmission Reliability Margin Values**

2. **Number:** MOD-009-0 (056.2)

3. **Purpose:** To ~~promote the consistent application of Transfer Capability margin calculations among Transmission System Providers and Transmission Owners, by developing methodologies for calculating Transmission Reliability Margin. This methodology shall comply with NERC definitions for Transmission Reliability Margin, the NERC Reliability Standards, and applicable Regional criteria. Regional Transmission Reliability Margin methodologies and the resulting Transmission Reliability Margin values shall be available to all participants of the electricity market, in order to facilitate intra- and inter-regional Transmission Service.~~promote the consistent application of transmission Transfer Capability margin calculations among Transmission System Providers and Transmission Owners.

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and implement a procedure to review Transmission Reliability Margin (TRM) calculations and resulting values of member Transmission ~~System~~ Service Providers to ensure they comply with the Regional TRM methodology, and are periodically updated and available to transmission users. This procedure shall include the following four required elements:

R1.1. Indicate the frequency under which the verification review shall be implemented.

R1.2. 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.

R1.3. Require review of the consistency of the Transmission Service 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 Available Transfer Capability determinations are often time constrained and thus will not permit the use of the same mechanics employed in the more rigorous Planning process.~~

R1.4. Require TRM values to be periodically updated (at least prior to each season — winter, spring, summer, and fall), as necessary, and made available to the Regional Reliability Organizations, NERC, and transmission users. ~~in the electricity market.~~

R2. The Regional Reliability Organization shall make documentation of its Regional TRM review procedure available to NERC on request (within 30 calendar days).

R3. The Regional Reliability Organization shall make documentation of the results of the most current implementation of its TRM review procedure available to NERC on request (within 30 calendar days).

C. Measures

M1. The Regional Reliability Organization shall have evidence that it provided to NERC upon request (within 30 calendar days) a copy of ~~the~~ its written procedure developed for the performance of periodic reviews of Regional TRM calculations.

M2. The Regional Reliability Organization shall have evidence it provided to NERC on request (within 30 calendar days) documentation of the results of the most current implementation of ~~the~~ its TRM review procedure.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: ~~Unaffiliated Third Party~~NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

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

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: The Regional Reliability Organization did not perform an annual review of all Transmission Service Providers within its Region~~al Reliability Organization~~ for consistency with its Regional TRM methodology~~ on an annual basis~~.

2.3. Level 3: Not applicable.

2.4. Level 4: The Regional Reliability Organization does not have a procedure for performing a TRM methodology consistency review of all Transmission Service Providers within its Region, or has not performed any such annual reviews. ~~on an annual basis.~~

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Define and Document Disturbance Monitoring Equipment Requirements.**

2. **Number:** PRC-002-0 (057.1)

3. **Purpose:** To ensure that Disturbance monitoring equipment is installed in a uniform manner to facilitate development of models and analyses of events.

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. The Regional Reliability Organization 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~~ System Disturbances. The comprehensive requirements shall include all of the following:

R1.1. Type of data recording capability (e.g., sequence-of-event, Fault recording, dynamic Disturbance recording).

R1.2. Equipment characteristics including but not limited to:

R1.2.1. Recording duration requirements.

R1.2.2. Time synchronization requirements.

R1.2.3. Data format requirements.

R1.2.4. Event triggering requirements

R1.3. Monitoring, recording, and reporting capabilities of the equipment.

R1.3.1. Voltage.

R1.3.2. Current.

R1.3.3. Frequency.

R1.3.4. MW and/or MVAR, as appropriate.

R1.4. Data retention capabilities (e.g., length of time data is to be available for retrieval).

R1.5. Regional coverage requirements (e.g., by voltage, geographic area, electric area or subarea).

R1.6. Installation requirements:

R1.6.1. Substations.

R1.6.2. Transmission lines.

R1.6.3. Generators.

R1.7. Responsibility for maintenance and testing.

R1.8. ~~Documentation Requirements:~~ Requirements for periodic (at least every five years) updating, review, and approval of the Regional requirements.

R2. The Regional Reliability Organization shall provide its requirements for the installation of Disturbance monitoring equipment to other Regional Reliability Organizations and NERC on request (30 calendar days).

C. Measures

M1. The Regional Reliability Organization's requirements for the installation of Disturbance monitoring equipment shall address all elements listed in Reliability Standard PRC-002-0_R1.

M2. The Regional Reliability Organization shall have evidence it provided its requirements for the installation of Disturbance monitoring equipment to other Regional Reliability Organizations and NERC on request (30 calendar days).

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: ~~Unaffiliated Third Party~~NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

On request by NERC (30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: The Regional Reliability Organization's Disturbance monitoring requirements do not address one of the eight requirements contained in Reliability Standard PRC-002-0_R1.

2.2. Level 2: The Regional Reliability Organization's Disturbance monitoring requirements do not address two of the eight requirements contained in Reliability Standard PRC-002-0_R1.

2.3. Level 3: The Regional Reliability Organization's Disturbance monitoring requirements do not address three of the eight requirements contained in Reliability Standard PRC-002-0_R1.

2.4. Level 4: The Regional Reliability Organization's Disturbance monitoring requirements were not provided or do not address four or more of the eight requirements contained in Reliability Standard PRC-002-0_R1.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Steady-State Data for Modeling and Simulation of the Interconnected Transmission System**

2. **Number:** MOD-010-0 (058.1)

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

4. **Applicability:**

   4.1. Transmission Owners specified in the data requirements and reporting procedures of MOD-011-0_R1

   4.2. Transmission Planners specified in the data requirements and reporting procedures of MOD-011-0_R1

   4.3. Generator Owners specified in the data requirements and reporting procedures of MOD-011-0_R1

   4.4. Resource Planners specified in the data requirements and reporting procedures of MOD-011-0_R1

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. The Transmission Owners, Transmission Planners Generator Owners, and Resource Planners ~~Responsible Entity (as specified within the applicable reporting procedures in Reliability Standard MOD-011-0_R1)~~ (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide appropriate equipment characteristics, system data, and existing and future Interchange ~~Transactions~~ Schedules in compliance with ~~its~~ its respective Interconnection~~-Wide~~ Regional steady-state modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-011-0_R1.

~~R1.for the modeling and simulation of the steady-state behavior of the NERC Interconnections: Eastern, Western, and ERCOT.~~

R2. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners ~~Responsible Entity (as specified within the applicable reporting procedures in Reliability Standard MOD-011-0_R1)~~ (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide this steady-state modeling and simulation data to the Regional Reliability Organizations, NERC, and those entities ~~Responsible for the Reliability of the Interconnected Transmission Systems, as~~ specified within ~~the applicable reporting procedures (~~Reliability Standard MOD-011-0_R1~~)~~. If no schedule exists, then these entities ~~the Responsible Entity~~ shall provide the data on request (30 calendar days).

C. Measures

M1. The Transmission Owner, Transmission Planner, Generator Owner, and Resource Planner~~Responsible Entity (as specified within the applicable reporting procedures in Standard MOD-011-0_R1)~~, (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall have evidence that it provided equipment characteristics, system data, and Interchange ~~Transactions~~ Schedules for steady-state modeling and simulation to the Regional Reliability Organizations and NERC as specified in ~~(~~Standard MOD-010-0_R1 and MOD-010-0_R2~~)~~.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

As specified within the applicable reporting procedures (Reliability Standard MOD-011-0_R2-M1). If no schedule exists, then on request (30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Steady-state data was provided, but was incomplete in one of the seven areas identified in Reliability Standard MOD-011-0_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Steady-state data was provided, but was incomplete in two or more of the seven areas identified in Reliability Standard MOD-011-0_R1.

2.4. Level 4: Steady-state data was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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3. Recirculation ballot of Version 0 standards.	December 27, 2004–January 7, 2005
4. 30-day posting before board adoption.	January 8, 2005–February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures.**

2. **Number:** MOD-011-0

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

4. **Applicability:**

   4.1. Regional Reliability Organization

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

B. Requirements

R1. The Regional Reliability Organizations within an Interconnection, in conjunction with the Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners, 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 Regional Reliability Organizations shall jointly coordinate the development of the data requirements and reporting procedures for that Interconnection. The Interconnection-wide requirements shall include the following steady-state data requirements:

R1.1. Bus (substation): name, nominal voltage, electrical demand supplied (consistent with the aggregated and dispersed substation demand data supplied per Reliability Standards MOD-016-0, MOD-017-0, and MOD-020-0), and location.

R1.2. 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.

R1.3. 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 Reliability Standard FAC-004-0 and FAC-005-0) equipment status, and metering locations.

R1.4. DC Transmission Line (overhead and underground): line parameters, Normal and Emergency Ratings, control parameters, rectifier data, and inverter data.

R1.5. 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 Reliability Standard FAC-004-0 and FAC-005-0.), and equipment status.

R1.6. Reactive Compensation (shunt and series capacitors and reactors): nominal Ratings, impedance, percent compensation, connection point, and controller device.

R1.7. Interchange Schedules: Existing and future Interchange Schedules and/or assumptions.

R2. The Regional Reliability Organizations within an Interconnection shall document their Interconnection's steady-state data requirements and reporting procedures, shall review those data requirements and reporting procedures (at least every five years), and shall make the data requirements and reporting procedures available on request (within five business days) to

Regional Reliability Organizations, NERC, and all users of the interconnected transmission systems.

C. Measures

M1. The Regional Reliability Organization shall have documentation of its Interconnection's steady-state data requirements and reporting procedures and shall provide the documentation as specified in Reliability Standard MOD-011-0_R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

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

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Data requirements and reporting procedures for steady-state data were provided, but were incomplete in one of the seven areas defined in Reliability Standard MOD-011-0_R1.

2.2. Level 2: Data requirements and reporting procedures for steady-state data were provided, but were incomplete in two of the seven areas defined in Reliability Standard MOD-011-0_R1.

2.3. Level 3: Not applicable.

2.4. 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 Reliability Standard MOD-011-0_R1.

E. Regional Differences

1. None identified.

Version History

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Standard Development Roadmap

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3. Recirculation ballot of Version 0 standards.	December 27, 2004–January 7, 2005
4. 30-day posting before board adoption.	January 8, 2005–February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Dynamics Data for Modeling and Simulation of the Interconnected Transmission System.**

2. **Number:** MOD-012-0 (058.3)

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

4. **Applicability:**

   4.1. Transmission Owners specified in the data requirements and reporting procedures of MOD-013-0_R4

   4.2. Transmission Planners specified in the data requirements and reporting procedures of MOD-013-0_R4

   4.3. Generator Owners specified in the data requirements and reporting procedures of MOD-013-0_R4

   4.4. Resource Planners specified in the data requirements and reporting procedures of MOD-013-0_R4

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners~~Responsible Entity (as specified in the reporting procedures of Reliability Standard MOD-013-0_R4)~~ (specified in the data requirements and reporting procedures of MOD-013-0_R4) shall provide appropriate equipment characteristics and system data in compliance with the respective Interconnection-~~Wide~~ wide Regional dynamics system modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-013-0_R4. ~~, for the modeling and simulation of the dynamic behavior of the NERC Interconnections: Eastern, Western, and ERCOT.~~

R2. The~~is~~ Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners~~Responsible Entity~~ (specified in the data requirements and reporting procedures of MOD-013-0_R4) shall provide dynamics system modeling and simulation data to its Regional Reliability Organization(s), NERC, and those ~~E~~entities ~~Responsible for the Reliability of the Interconnected Transmission Systems as~~ specified within the applicable reporting procedures identified in~~(~~ Reliability Standard MOD-013-0_R1~~4)~~. If no schedule exists, then these entities ~~Responsible Entity~~ shall provide data on request (30 calendar days).

C. Measures

M1. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R4) ~~Responsible Entity~~ shall each have evidence that it provided equipment characteristics and system data for dynamics system modeling and simulation in accordance with Reliability Standard MOD-012-0_R1 and Reliability Standard MOD-012-0_R2.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

As specified within the applicable reporting procedures (Reliability Standard MOD-013-0). If no schedule exists, then on request (30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Dynamics data was provided, but was incomplete in one of the four areas identified in Reliability Standard MOD-013-0_R41.

2.2. Level 2: Not Applicable.

2.3. Level 3: Dynamics data was provided, but was incomplete in two or more of the four areas identified in Reliability Standard MOD-013-0_R41.

2.4. Level 4: Dynamics data was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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4. 30-day posting before board adoption.	January 8, 2005–February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures**

2. **Number:** MOD-013-0

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

4. **Applicability:**

   4.1. Regional Reliability Organization

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

B. Requirements

R1. The Regional Reliability Organization, in coordination with ~~the~~ its Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners~~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 Regional Reliability Organizations shall jointly coordinate on the development of the data requirements and reporting procedures for that Interconnection. Each set of Interconnection-~~Wide~~ wide dynamics data requirements shall include the following dynamics data requirements:~~address the following~~:

R1.1. 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.

R1.1.1. ~~However, e~~Estimated or typical manufacturer's dynamics data, based on units of similar design and characteristics, may be submitted when unit-specific dynamics data cannot be obtained. In no case shall other than unit-specific data be reported for generator units installed after 1990.

R1.1.2. The Interconnection-~~Wide~~ wide requirements shall specify unit size thresholds for permitting:

– The use of non-detailed vs. detailed models,

– The netting of small generating units with bus load, and

– The combining of multiple generating units at one plant.

R1.2. Device specific dynamics data shall be reported for dynamic devices, including, among others, static VAR controllers, high voltage direct current systems, flexible AC transmission systems, and static compensators.

R1.3. Dynamics data representing electrical ~~D~~demand ~~(Load)~~ characteristics as a function of frequency and voltage.

R1.4. Dynamics data shall be consistent with the reported steady-state (power flow) data supplied per Reliability Standard MOD-010-0_R1.

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

C. Measures

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

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: ~~Unaffiliated Third Party~~NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

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

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

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

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

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

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

E. Regional Differences

1. None.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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4. 30-day posting before board adoption.	January 8, 2005– February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Development of Steady-State System Models**

2. **Number:** MOD-014-0 (058.5)

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

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. The Regional Reliability Organization(s) within each Interconnection shall coordinate and jointly develop and maintain a library of solved (converged) Interconnection-~~Specific~~ apecific steady-state system models. The Interconnection-~~Specific~~ apecific models shall include near- and longer-term planning horizons that are representative of system conditions for projected seasonal ~~Peak~~peak, minimum, and other appropriate system ~~Demand~~ demand levels.

R2. The Regional Reliability Organization(s) within each Interconnection shall coordinate and jointly develop steady-state system models annually for selected study years, as determined by the Regional Reliability Organizations within its Interconnection. The Regional Reliability Organization shall provide the most recent solved (converged) Interconnection-specific steady-state models to NERC in accordance with each Interconnection's schedule for submission.

C. Measures

M1. Each Regional Reliability Organization shall have ~~evidence it contributed to the development of its~~ Interconnection-specific steady-state system models as specified in MOD-014-0_R1 and MOD-014-0_R2.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: ~~Unaffiliated Third Party~~NERC.

   1.2. Compliance Monitoring Period and Reset Timeframe

   Development of steady-state system models: annually, as determined by each Interconnection's schedule.

   Most recent steady-state system models: 30 calendar days.

   1.3. Data Retention

   None specified.

   1.4. Additional Compliance Information

   None.

2. Levels of Non-Compliance

2.1. Level 1: One of a Regional Reliability Organization's cases ~~was~~ either was not submitted by ~~the~~ each Interconnection's 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.

2.2. Level 2: Two of a Regional Reliability Organization's cases were either not submitted by ~~the~~ each Interconnection's 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).

2.3. Level 3: Three of a Regional Reliability Organization's cases were either not submitted by each Interconnection's~~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).

2.4. Level 4: Four or more of a Regional Reliability Organization's cases were either not submitted by each Interconnection's ~~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).

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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4. 30-day posting before board adoption.	January 8, 2005–February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Development of Dynamics System Models**

2. **Number:** MOD-015-0 (058.6)

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

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. The Regional Reliability Organization(s) within each Interconnection shall coordinate and jointly develop and maintain a library of initialized (with no Faults or system Disturbances) Interconnection-~~Specific~~ specific dynamics system models linked to the steady-state system models, as appropriate, of Reliability Standard MOD-014-0_R1.

R1.1. The Regional Reliability Organization(s) shall develop Interconnection-~~Specific~~ specific dynamics system models for at least two timeframes (present or near-term model and a future or longer-term model), and additional seasonal and ~~Demand~~ demand level models, as necessary, to analyze the dynamic response of that Interconnection.

R2. The Regional Reliability Organization(s) within each Interconnection shall develop Interconnection dynamics system models for their Interconnection annually for selected study years as determined by the Regional Reliability Organization(s) within each Interconnection and shall provide the most recent initialized (approximately 25 seconds, no-fault) models to ~~NERC on request (30 calendar days).~~NERC in accordance with each Interconnection's schedule for submission.

C. Measures

M1. The Regional Reliability Organization shall have ~~evidence that it contributed to the development of its~~ Interconnection-~~Specific~~ specific dynamics system models in accordance with Reliability Standard MOD-015-0_R1, MOD-015-0_R2 and MOD-015-0_R3.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: ~~Unaffiliated Third Party~~NERC.

   1.2. Compliance Monitoring Period and Reset Timeframe

   Development of dynamics system models: annually in accordance with each Interconnection's schedule.

   Most recent dynamics system models: 30 calendar days.

   1.3. Data Retention

   None specified.

   1.4. Additional Compliance Information

   None.

2. Levels of Non-Compliance

2.1. Level 1: One of a Regional Reliability Organization's cases was either not submitted by each Interconnection's~~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.

2.2. Level 2: Two of a Regional Reliability Organization's cases were either not submitted by each Interconnection's~~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).

2.3. Level 3: Three of a Regional Reliability Organization's cases were either not submitted by each Interconnection's~~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).

2.4. Level 4: Four or more of a Regional Reliability Organization's cases were either not submitted by each Interconnection's~~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).

E. Regional Differences

1. None.

Version History

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6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Methodologies for Determining Electrical Facility Ratings**

2. **Number:** FAC-004-0 (060.1)

3. **Purpose:** To ensure that electrical facilities used in the transmission and storage of electricity are ~~R~~r~~r~~ated in compliance with applicable Regional Reliability Organization requirements.

4. **Applicability:**

   4.1. Transmission Owner

   4.2. Generator Owner

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. The Transmission Owner and Generator Owner shall each document the methodology(ies) used to determine its electrical ~~Facility~~ facility and equipment Rating. Further, the methodology(ies) shall comply with applicable Regional Reliability Organization requirements. The documentation shall address and include

R1.1. The methodology(ies) used to determine Facility and equipment Rating of the items listed for both normal and emergency conditions:

R1.1.1. Transmission circuits.

R1.1.2. Transformers.

R1.1.3. Series and shunt reactive elements.

R1.1.4. Terminal equipment (e.g., switches, breakers, current transformers, etc~~.~~).

R1.1.5. VAR compensators.

R1.1.6. High voltage direct current converters.

R1.1.7. Any other device listed as a Limiting Element.

R1.2. 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.

R1.3. In cases where protection systems and control settings constitute a loading limit on a facility, this limit shall become the Rating for that facility.

R1.4. 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.

R1.5. The documentation shall identify the assumptions used to determine each of the ~~Facility~~ 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.

R2. The Transmission Owner and Generator Owner shall provide documentation of the methodology(ies) used to determine its transmission ~~Facility~~ facility and equipment Ratings to the Regional Reliability Organization(s) and NERC on request (30 calendar days).

C. Measures

M1. The Transmission Owner or Generator Owner shall provide documentation that the methodology(ies) used for determining Facility and equipment Ratings meets the requirements of Standard FAC-004-0_R1 as specified in Standard FAC-004-0_R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Facility and equipment Rating methodology(ies) do not address one of the five elements ~~(1-5)~~ listed in Reliability Standard FAC-004-0_R1.

2.2. Level 2: N/A.

2.3. Level 3: Facility and equipment Rating methodology(ies) do not address two of the five elements ~~(1-5)~~ listed in Reliability Standard FAC-004-0_R1.

2.4. Level 4: Facility and equipment Rating methodology(ies) do not address three or more of the five elements ~~(1-5)~~ listed in Reliability Standard FAC-004-0_R1, or no Facility and equipment Rating methodology was provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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Description of Current Draft:

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Future Development Plan:

Anticipated Actions	**Anticipated Date**
1. Seek endorsement of NERC technical committees.	November 9–11, 2004
2. First ballot of Version 0 standards.	December 1–10, 2004
3. Recirculation ballot of Version 0 standards.	December 27, 2004–January 7, 2005
4. 30-day posting before board adoption.	January 8, 2005–February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Electrical Facility Ratings for System Modeling**

2. **Number:** FAC-005-0 (060.2)

3. **Purpose:** To ensure that electrical facilities used in the transmission and storage of electricity are Rated in compliance with applicable Regional Reliability Organization requirements.

4. **Applicability:**

   4.1. Transmission Owner

   4.2. Generator Owner

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. The ~~Transmission~~ transmission Owner, and Generator Owner shall each have on file or be able to readily provide, a document or database identifying the Normal and Emergency Ratings of all of ~~their~~ its transmission facilities (e.g., lines, transformers, terminal equipment, and storage devices) that are part of the interconnected transmission systems. Seasonal variations in Ratings shall be included as appropriate.

R1.1. The Ratings shall be consistent with the entity's methodology(ies) for determining Facility Ratings and shall be updated as facility changes occur.

R2. The Transmission Owner and Generator Owner shall provide the Normal and Emergency Facility Ratings of all its transmission facilities to the Regional Reliability Organization(s) and NERC on request (30 calendar days).

C. Measures

M1. The Transmission Owner and Generator Owner shall provide documentation of its ~~Facility~~ facility Ratings as specified in Reliability Standard FAC-005-0_R1 and Standard FAC-005-0_R2.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Timeframe

   On request (30 calendar days.)

   1.3. Data Retention

   None specified.

   1.4. Additional Compliance Information

   None.

2. **Levels of Non-Compliance**

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

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

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

2.4. Level 4: Facility Ratings were not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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4. 30-day posting before board adoption.	January 8, 2005– February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

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

2. **Number:** MOD-016-0 (061.1)

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

4. **Applicability:**

   4.1. Planning Authority

   4.2. Regional Reliability Organization

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

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

R1.1. The aggregated and dispersed data submittal requirements shall ensure that consistent data is supplied for Reliability Standards ~~052, 058, and 061~~TPL-005-0, TPL-006-0, MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-0, MOD-014-0, MOD-015-0, MOD-016, MOD-017-0, MOD-018-0, MOD-019-0, MOD-020-0, and MOD-021-0.

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

C. Measures

M1. The Planning Authority and Regional Reliability Organization shall each provide evidence to its Compliance Monitor that it provided data and reporting procedures per Reliability Standard MOD-016-0_R1 and MOD-016-0_R2.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

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

   1.2. Compliance Monitoring Period and Reset Timeframe

   On request (five business days.)

   1.3. Data Retention

   None specified.

   1.4. Additional Compliance Information

   None.

2. **Levels of Non-Compliance**

2.1. Level 1: Identified the scope and details of ~~Demand~~demand, Net Energy for Load, and controllable DSM data to be reported and the reporting procedures but did not specify that consistent data is to be supplied for Reliability Standards TPL-005-0, TPL-006-0, MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-0, MOD-014-0, MOD-015-0, MOD-016, MOD-017-0, MOD-018-0, MOD-019-0, MOD-020-0, and MOD-021-0~~052, 058, and 061~~.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Did not identify the scope and details of ~~Demand~~demand, Net Energy for Load, and controllable DSM data to be reported and the reporting procedures.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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Future Development Plan:

Anticipated Actions	Anticipated Date
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3. Recirculation ballot of Version 0 standards.	December 27, 2004–January 7, 2005
4. 30-day posting before board adoption.	January 8, 2005–February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Aggregated Actual and Forecast Demands and Net Energy for Load**

2. **Number:** MOD-017-0 (061.4)

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

4. **Applicability:**

   4.1. Load-Serving Entity

   4.2. Planning Authority

   4.3. Resource Planner

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. The Load-Serving Entity, Planning Authority and Resource Planner shall each provide the following information annually on an aggregated Regional, subregional, Power Pool, individual system, or Load-Serving Entity basis to NERC, the Regional Reliability Organizations, and any other~~those~~ entities specified by the documentation in Standard MOD-016-0_R1.

R1.1. Integrated hourly ~~Demands~~ demands in megawatts (MW) for the prior year.

R1.2. Monthly and annual ~~Peak~~ peak hour actual ~~Demands~~ demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year.

R1.3. Monthly ~~Peak~~ peak hour forecast ~~Demands~~ demands in MW and Net Energy for Load in GWh for the next two years.

R1.4. Annual Peak hour forecast ~~Demands~~ demands (summer and winter) in MW and annual Net Energy for ~~Load~~ load in GWh for at least five years and up to ten years into the future, as requested.

C. Measures

M1. Load-Serving Entity, Planning Authority, and Resource Planner shall each provide evidence to its Compliance Monitor that it provided ~~Load~~ load data per Standard MOD-017-0_R1.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Timeframe

   Annually or as specified in the documentation (Standard MOD-016-0_R1.)

   1.3. Data Retention

   None specified.

   1.4. Additional Compliance Information

   None.

2. Levels of Non-Compliance

2.1. Level 1: Did not provide actual and forecast ~~Demands~~ demands and Net Energy for Load data in one of the four areas as required in Reliability Standard MOD-017-0_R1.

2.2. Level 2: Did not provide actual and forecast ~~Demands~~ demands and Net Energy for Load data in two of the four areas as required in Reliability Standard MOD-017-0_R1.

2.3. Level 3: Did not provide actual and forecast ~~Demands~~ demands and Net Energy for Load data in three of the four areas as required in Reliability Standard MOD-017-0_R1.

2.4. Level 4: Did not provide actual and forecast ~~Demands~~ demands and Net Energy for Load data in any of the areas as required in Reliability Standard MOD-017-0_R1.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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Future Development Plan:

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4. 30-day posting before board adoption.	January 8, 2005–February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title: Treatment of Nonmember Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load**

2. **Number:** MOD-018-0 (061.5)

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

4. **Applicability:**

   4.1. Load-Serving Entity

   4.2. Planning Authority

   4.3. Transmission Planner

   4.4. Resource Planner

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. The Load-Serving Entity, Planning Authority, Transmission Planner and Resource Planner's report of actual and forecast ~~Demand~~ demand data (reported on either an aggregated or dispersed basis) shall:

R1.1. Indicate whether the ~~Demand~~ demand data of nonmember entities within an area or Regional Reliability Organization are included, and

R1.2. Address assumptions, methods, and the manner in which uncertainties are treated in the forecasts of aggregated ~~Peak~~ peak ~~Demands~~ demands and Net Energy for Load.

R1.3. Items (MOD-018-0_R1.1) and (MOD-018-0_R1.2) shall be addressed as described in the reporting procedures developed for Standard MOD-016-0_R1.

R2. The Load-Serving Entity, Planning Authority, Transmission Planner and Resource Planner shall each report data associated with Reliability Standard MOD-018-0_R1 to NERC, the Regional Reliability Organization, Load-Serving Entity, Planning Authority, and Resource Planner on request (within 30 calendar days).

C. Measures

M1. The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each provide evidence to its Compliance Monitor that its actual and forecast ~~Demand~~ demand data ~~was~~ were addressed as described in the reporting procedures developed for Reliability Standard MOD-018-0_R1.

M2. The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each report current information for Reliability Standard MOD-018-0_R1 to NERC, the Regional Reliability Organization, Load-Serving Entity, Planning Authority, and Resource Planner on request (within 30 calendar days).

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

On Request (within 30 calendar days~~.~~).

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Information for Reliability Standard MOD-018-0 item~~s~~ R1.1 or R1.2 was not provided.

2.2. Level 2: Information for Reliability Standards MOD-018-0 items R1.1 and R1.2 was not provided.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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4. 30-day posting before board adoption.	January 8, 2005– February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Reporting of Interruptible Demands and Direct Control Load Management**

2. **Number:** MOD-019-0 (061.6)

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

4. **Applicability:**

   4.1. Load-Serving Entity

   4.2. Planning Authority

   4.3. Transmission Planner

   4.4. Resource Planner

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each provide annually its forecasts of interruptible ~~Demands~~ demands and Direct Control Load Management (DCLM) data for at least five years and up to ten years into the future, as requested, for summer and winter ~~Peak~~ peak ~~System~~ system conditions to NERC, the Regional Reliability Organizations, and other entities (Load-Serving Entities~~y~~, Planning ~~Authority~~ Authorities, and Resource Planners) as specified by the documentation in Reliability Standard MOD-016-0_R1**.**

C. Measures

M1. The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each provide evidence to its Compliance Monitor that it provided forecasts of interruptible ~~Demands~~ demands and DCLM data per Reliability Standard MOD-019-0_R1.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Each Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Timeframe

   Annually or as specified in the documentation (Reliability Standard MOD-016-0_R1.)

   1.3. Data Retention

   None specified.

   1.4. Additional Compliance Information

   None.

2. **Levels of Non-Compliance**

   2.1. Level 1: Not applicable.

   2.2. Level 2: Not applicable.

   2.3. Level 3: Not applicable.

2.4. Level 4: Did not provide forecasts of interruptible Demands and DCLM ~~the controlled Demand-Side Management~~ data as required in Standard MOD-019-0_R1.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Security Center Coordinators**

2. **Number:** MOD-020-0 (061.7)

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

4. **Applicability:**

   4.1. Load-Serving Entity

   4.2. Transmission Planner

   4.3. Resource Planner

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. The Load-Serving Entity, ~~Planning Authority~~Transmission Planner, and Resource Planner shall each make known its amount of interruptible demands and Direct Control Load Management (DCLM) to ~~system~~ Transmission ~~operators~~ Operators, Balancing Authorities, and ~~security center~~Reliability Coordinators on request within 30 calendar days.

C. Measures

M1. The Load-Serving Entity, ~~Planning Authority~~Transmission Planner, and Resource Planner each make known its amount of interruptible ~~Demands~~ demands and DCLM to ~~Reliability Authority(ies)~~, ~~and Transmission~~ Transmission Operator~~(~~s, Balancing Authorities~~)~~ and Reliability Coordinators on request within 30 calendar days.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Timeframe

   On request (within 30 calendar days~~.~~).

   1.3. Data Retention

   None specified.

   1.4. Additional Compliance Information

   None.

2. **Levels of Non-Compliance**

   2.1. Level 1: Interruptible Demands and DCLM data were provided to ~~the~~ Reliability ~~Authority~~Coordinator~~(ie~~s~~)~~, Balancing Authorities, and Transmission Operator~~(~~s~~)~~, but were incomplete.

   2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Interruptible Demands and DCLM data were not provided to ~~the~~ Reliability ~~Authority~~Coordinator~~(ie~~s, Balancing Authorities~~)~~, and Transmission Operator~~(~~s~~)~~.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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3. Recirculation ballot of Version 0 standards.	December 27, 2004–January 7, 2005
4. 30-day posting before board adoption.	January 8, 2005–February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title: Documentation of the Accounting Methodology for the Effects of Controllable Demand-Side Management in Demand and Energy Forecasts.**

2. **Number:** MOD-021-0 (061.8)

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

4. **Applicability:**

   4.1. Load-Serving Entity

   4.2. Transmission Planner

   4.3. Resource Planner

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. The Load-Serving Entity~~'s,~~ ~~Planning Authority's~~Transmission Planner~~'s~~ and Resource Planner's forecasts shall each clearly document how the Demand and energy effects of DSM programs (such as conservation, time-of-use rates, interruptible Demands, and Direct Control Load Management) are addressed.

R2. The Load-Serving Entity, Transmission Planner~~Planning Authority~~ and Resource Planner shall each include information detailing how Demand-Side Management measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load in the data reporting procedures of Standard MOD-016-0_R1.

R3. The Load-Serving Entity, Transmission Planner~~Planning Authority~~ and Resource Planner shall each make documentation on the treatment of its DSM programs available to NERC on request (within 30 calendar days).

C. Measures

M1. The Load-Serving Entity, Transmission Planner~~Planning Authority~~ and Resource Planner forecasts clearly document how the ~~Demand~~ demand and ~~energy~~ energy effects of DSM programs (such as conservation, time-of-use rates, interruptible ~~Demands~~demands, and Direct Control Load Management) are addressed.

M2. The Load-Serving Entity, Transmission Planner~~Planning Authority~~ and Resource Planner information detailing how Demand-Side Management measures are addressed in the forecasts of Peak Demand and annual Net Energy for Load are included in the data reporting procedures of Reliability Standard MOD-016-0_R1.

M3. The Load-Serving Entity, Planning Authority and Resource Planner shall each provide evidence to its Compliance Monitor that it provided documentation on the treatment of DSM programs to NERC as requested (within 30 calendar days).

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days~~.~~).

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Documentation on the treatment of DSM programs in the ~~Demand~~ demand and energy forecasts was provided, but was incomplete.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Documentation on the treatment of DSM programs in the ~~Demand~~ demand and energy forecasts was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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Description of Current Draft:

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Future Development Plan:

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4. 30-day posting before board adoption.	January 8, 2005–February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Regional Procedure for Transmission Protection System Misoperations.**

2. **Number:** PRC-003-0 (063.1)

3. **Purpose:** To ensure all transmission protection system misoperations are analyzed for cause and corrective action and maintenance and testing programs are developed and implemented

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Proposed Effective Date:** April 1~~February 8~~, 2004

B. Requirements

R1. Each Regional Reliability Organization shall have a procedure for the monitoring, review, analysis, and correction of all transmission protection system misoperations. Each Regional Reliability Organization's procedure shall include the following elements:

R1.1. Requirements for monitoring and analysis of all transmission protective device misoperations.

R1.2. Description of the data reporting requirements (periodicity and format) for those misoperations that adversely affects the reliability of the Bulk Electric Systems as specified by the Regional Reliability Organization.

R1.3. Process for review, follow up, and documentation of corrective action plans for misoperations.

R1.4. Identification of the Regional Reliability Organization group responsible for the procedure and the process for Regional Reliability Organization approval of the procedure.

R1.5. Regional Reliability Organization definition of misoperations.

R2. Each Regional Reliability Organization shall maintain documentation of its procedure and provide it to NERC on request (within 30 calendar days).

C. Measures

M1. The Regional Reliability Organization shall have a procedure for the monitoring, review, analysis, and correction of transmission protection system misoperations as defined in Standard PRC-003-0_R1.

M2. The Regional Reliability Organization shall have evidence it provided documentation of its procedure as defined in Reliability Standard PRC-003-0_R2.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   NERC.

   1.2. Compliance Monitoring Period and Reset Timeframe

   On request (within 30 calendar days.)

   1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: The Regional Reliability Organization's procedure does not address all the requirements as defined ~~above~~ in Reliability Standard PRC-003-0_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: The Regional Reliability Organization's procedure was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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4. 30-day posting before board adoption.	January 8, 2005–February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Analysis and Reporting of Transmission Protection System Misoperations**

2. **Number:** PRC-004-0 (063.2)

3. **Purpose:** To ensure all transmission protection system misoperations are analyzed for cause and corrective action and maintenance and testing programs are developed and implemented.

4. **Applicability:**

   4.1. Transmission Owner

   4.2. Generator Owner that owns a transmission protection system

   4.3. Distribution Provider that owns a transmission protection system

5. **Proposed Effective Date:** April 1~~**February 8**~~**,** 2005

B. Requirements

R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a transmission protection system~~(s)~~ shall analyze all protection system misoperations and shall take corrective actions to avoid future misoperations.

R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a transmission protection system~~(s)~~ shall provide to ~~the~~ its affected Regional Reliability Organization and NERC on request (within 30 calendar days) documentation of the misoperations analyses and corrective actions according to the Regional Reliability Organization's procedures of Reliability Standard PRC-003-0_R1.

C. Measures

M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a transmission protection system~~(s)~~ shall have evidence it analyzed its protection system misoperation(s) and took corrective action(s) to avoid future misoperations.

M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a transmission protection system~~(s)~~ shall have evidence it provided documentation of its protection system misoperations, analyses, and corrective action(s) according to the Regional Reliability Organization procedures of Reliability Standard PRC-003-0_R1.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Timeframe

   On request (within 30 calendar days.)

   1.3. Data Retention

   None specified.

   1.4. Additional Compliance Information

   None.

2. **Levels of Non-Compliance**

2.1. Level 1: Documentation of transmission protection system misoperations is complete according to Reliability Standard PRC-003-0_R1, but documentation of corrective actions taken for all identified misoperations is incomplete.

2.2. Level 2: Documentation of corrective actions taken for misoperations is complete, but documentation of transmission protection system misoperations is incomplete according to Reliability Standard PRC-003-0_R1.

2.3. Level 3: Documentation of misoperations and corrective actions is incomplete.

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

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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4. 30-day posting before board adoption.	January 8, 2005–February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Transmission Protection System Maintenance and Testing**

2. **Number:** PRC-005-0 (063.3)

3. **Purpose:** To ensure all transmission protection system misoperations are analyzed for cause and corrective action, and maintenance and testing programs are developed and implemented.

4. **Applicability:**

   4.1. Transmission Owner

   4.2. Generator Owner that owns Transmission protection systems

   4.3. Distribution Provider that owns Transmission protection systems

5. **Proposed Effective Date:** ~~February 8~~April 1, 2004

B. Requirements

R1. The Transmission Owner, Generator Owner and Distribution Provider that owns a transmission protection system ~~(s)~~ shall have a transmission protection system maintenance and testing program~~(s)~~ in place. The program(s) shall include:

R1.1. Transmission protection system identification shall include but are not limited to:

R1.1.1. Relays.

R1.1.2. Instrument transformers.

R1.1.3. Communications systems, where appropriate.

R1.1.4. Batteries.

R1.2. Documentation of maintenance and testing intervals and their basis.

R1.3. Summary of testing procedure.

R1.4. Schedule for system testing.

R1.5. Schedule for system maintenance.

R1.6. Date last tested/maintained.

R2. The Transmission Owner, ~~and~~ Generator Owner, and Distribution Provider that owns a transmission protection system~~(s)~~ shall provide documentation of ~~the~~ its transmission protection system program and its implementation to the appropriate Regional Reliability Organization and NERC on request (within 30 calendar days).

C. Measures

M1. The Transmission Owner, ~~or~~ Generator Owner, and Distribution Provider that owns a transmission ~~system~~ protection system~~(s)~~ shall have a transmission protection system maintenance and testing program~~(s)~~ as defined in Reliability Standard PRC-005-0_R1.

M2. The Transmission Owner, ~~and~~ Generator Owner, and Distribution Provider that owns a transmission ~~system~~ protection system~~(s)~~ shall have evidence it provided documentation of its transmission protection system maintenance and testing program~~(s)~~ and the implementation of its program~~(s)~~ as defined in Reliability Standard PRC-003-0_R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

Each Regional Reliability Organization shall report compliance and violations to NERC via the NERC ~~Compliance~~ compliance ~~Reporting~~ reporting process.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

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

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

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

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

E. Regional Differences

1. None identified.

Version History

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Standard Development Roadmap

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5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title: Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs**

2. **Number:** PRC-006-0 (067.1)

3. **Purpose:** Provide last resort system preservation measures by implementing an Under Frequency Load Shedding (UFLS) program.

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Proposed Effective Date:** ~~February 8~~April 1, ~~2004~~2005

B. Requirements

R1. Each Regional Reliability Organization shall develop, coordinate, and document an UFLS program, which shall include the following:

R1.1. Requirements for coordination of UFLS programs within the subregions, Regional Reliability Organization~~,~~ and, where appropriate, among Regional Reliability Organizations.

R1.2. Design details shall include, but are not limited to:

R1.2.1. Frequency set points.

R1.2.2. Size of corresponding ~~Load~~ load shedding blocks (% of connected ~~Loads~~loads.)

R1.2.3. Intentional and total tripping time delays.

R1.2.4. Generation protection.

R1.2.5. Tie tripping schemes.

R1.2.6. Islanding schemes.

R1.2.7. Automatic ~~Load~~ load restoration schemes.

R1.2.8. Any other schemes that are part of or impact the UFLS programs.

R1.3. A Regional Reliability Organization UFLS program database. This database shall be updated as specified in the Regional Reliability Organization 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.

R1.4. ~~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:

R1.4.1. A review of the frequency set points and timing, and

R1.4.2. Dynamic simulation of possible Disturbance that cause the Region or portions of the Region to experience the largest imbalance between Demand (Load) and generation.

R2. The Regional Reliability Organization shall provide documentation of its UFLS program and its database information to NERC on request (within 30 calendar days).

R3. The Regional Reliability Organization shall provide documentation of the ~~technical~~ assessment of its UFLS program to NERC on request (within 30 calendar days).

C. Measures

M1. The Regional Reliability Organization shall have documentation of the UFLS program and current UFLS database.

M2. The Regional Reliability Organization shall have evidence it provided documentation of its UFLS program and its database information to NERC as specified in Reliability Standard PRC-006-0_R2.

M3. The Regional Reliability Organization shall have evidence it provided documentation of its ~~technical~~ assessment of its UFLS program to NERC as specified in Reliability Standard PRC-006-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: ~~Unaffiliated Third Party~~NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

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

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Documentation demonstrating the coordination of the Regional Reliability Organization's UFLS program was incomplete in one of the elements in Reliability Standard PRC-006-0_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

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

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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6. Effective date.	April 1, 2005

A. Introduction

1. **Title: Assuring Consistency of Entity Underfrequency Load Shedding Programs with Regional Reliability Organization's Underfrequency Load Shedding Program Requirements**

2. **Number:** PRC-007-0 (067.2)

3. **Purpose:** Provide last resort System preservation measures by implementing an Under Frequency Load Shedding (UFLS) program.

4. **Applicability:**

   4.1. Transmission Owner required by its Regional Reliability Organization to own a UFLS program

   4.2. Transmission Operator required by its Regional Reliability Organization to operate a UFLS program

   4.3. Distribution Provider required by its Regional Reliability Organization to own or operate a UFLS program

   4.4. Load-Serving Entity required by its Regional Reliability Organization to operate a UFLS program

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

B. Requirements

R1. The Transmission Owner and Distribution Provider, with a UFLS program (as required by its Regional Reliability Organization) shall ensure that its UFLS program is consistent with its Regional Reliability Organization's UFLS program requirements.

R2. The Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide, and annually update, its underfrequency data as necessary for its Regional Reliability Organization to maintain and update a UFLSprogram database.

R3. The Transmission Owner and Distribution Provider that owns a UFLS program (as required by its Regional Reliability Organization) shall provide its documentation of that UFLS program to its Regional Reliability Organization on request (30 calendar days).

C. Measures

M1. Each Transmission Owner's and Distribution Provider's UFLS program shall be consistent with its associated Regional Reliability Organization's UFLS program requirements.

M2. Each Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity that owns or operates a UFLS program shall have evidence that it provided its associated Regional Reliability Organization and NERC with documentation of the UFLS program on request (30 calendar days).

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days).

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: The evaluation of the entity's UFLS program for consistency with its Regional Reliability Organization's UFLS program is incomplete or inconsistent in one or more requirements of Reliability Standard PRC-006-0_R1, but is consistent with the required amount of Load shedding.

2.2. Level 2: The amount of Load shedding is less than 95percent of the Regional requirement in any of the Load steps.

2.3. Level 3: The amount of Load shedding is less than 90percent of the Regional requirement in any of the Load steps.

2.4. Level 4: The evaluation of the entity's UFLS program for consistency with its Regional Reliability Organization's UFLS program was not provided or the amount of Load shedding is less than 85 percent of the Regional requirement on any of the Load steps.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. Title: **Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program**

2. Number: PRC-008-0 (067.3)

3. Purpose: Provide last resort system preservation measures by implementing an Under Frequency Load Shedding (UFLS) program.

4. Applicability:

4.1. Transmission Owner required by its Regional Reliability Organization to have a UFLS program

4.2. Distribution Provider required by its Regional Reliability Organization to have a UFLS program

5. Proposed Effective Date: April 1~~February 8~~, 2005

B. Requirements

R1. The Transmission Owner~~, Transmission Operator,~~ and Distribution Provider with a UFLS program (as required by ~~the~~ its Regional Reliability Organization)~~ to have an UFLS program~~ shall have a UFLS equipment maintenance and testing program in place. ~~This~~ This UFLS equipment maintenance and testing program shall include UFLS equipment identification, the schedule for UFLS equipment testing, and the schedule for UFLS equipment maintenance.

R2. The Transmission Owner~~, ,~~ and Distribution Provider with a UFLS program (as required by ~~the~~ its Regional Reliability Organization~~ to have a UFLS program~~) shall implement~~ation~~ its UFLS equipment maintenance and testing program and shall provide UFLS maintenance and testing program results to ~~the~~ its Regional Reliability Organization~~(s)~~ and NERC on request (within 30 calendar days).

C. Measures

M1. ~~The~~ Each Transmission Owner's~~,~~ ~~Transmission Operator,~~ and Distribution Provider's ~~required by the Regional Reliability Organization to have a~~ UFLS ~~program shall have a UFLS~~ equipment maintenance and testing program contains~~in place that contains~~ the elements specified in Reliability Standard PRC-007-0_R1.

M2. ~~The~~ Each Transmission Owner~~,~~ and~~Transmission Operator,~~ Distribution Provider ~~required by the Regional Reliability Organization to have a UFLS program~~ shall have evidence that it provided the results of ~~the~~ its UFLS equipment maintenance and testing program's implementation to ~~the~~ its Regional Reliability Organization~~(s)~~ and NERC on request (within 30 calendar days).

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days).

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

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

2.2. Level 2: Complete documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.

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

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

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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

Development Steps Completed:

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4. 30-day posting before board adoption.	January 8, 2005–February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

\

A. Introduction

1. **Title:** **Analysis and Documentation of Underfrequency Load Shedding Performance Following an Underfrequency Event**

2. **Number:** PRC-009-0 (067.4)

3. **Purpose:** Provide last resort System preservation measures by implementing an Under Frequency Load Shedding (UFLS) ~~Program~~program.

4. **Applicability:**

   4.1. Transmission Owner required by its Regional Reliability Organization to own a UFLS program

   4.2. Transmission Operator required by its Regional Reliability Organization to operate a UFLS program

   4.3. Load-Serving Entity required by the Regional Reliability Organization to operate a UFLS program

   4.4. Distribution Provider required by the Regional Reliability Organization to own or operate a UFLS program

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. The Transmission Owner, Transmission Operator, Load-Serving Entity~~,~~ and Distribution Provider~~,~~ that owns or operates a UFLS program (as required by ~~the~~ its Regional Reliability Organization) ~~to have anUFLS program~~ shall~~-~~ analyze and document its UFLS program performance in accordance with its Regional Reliability Organization's UFLS program. The analysis shall ~~, includ~~address~~ing~~ 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:

R1.1. A description of the event including initiating conditions.

R1.2. A review of the UFLS set points and tripping times.

R1.3. A simulation of the event.

R1.4. A summary of the findings.

R2. The Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by ~~the~~ its Regional Reliability Organization) ~~to have an UFLS program~~ shall provide documentation of the analysis of ~~its~~ the UFLS program to ~~the~~ its Regional Reliability Organization~~(s)~~ and NERC on request 90 calendar days after the system event.

C. Measures

M1. ~~The~~ Each Transmission Owner's, Transmission Operator's, Load-Serving Entity's~~,~~ and Distribution Provider~~-''~~s~~required by the Regional Reliability Organization to have an UFLS program~~ ~~'s analysis and~~ documentation of the UFLS program performance following an underfrequency event ~~shall~~ includes all elements identified in Reliability Standard PRC-009-0_R1.

M2. ~~The~~ Each Transmission Owner, Transmission Operator, Load-Serving Entity~~,~~ and Distribution Provider~~,~~ ~~required by the Regional Reliability Organization to~~that ~~have~~ owns or operate a UFLS program, shall have evidence it provided documentation of the analysis of ~~its~~ the UFLS program performance following an underfrequency event as specified in Reliability Standard PRC-009-0_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

On request 90 calendar days after the system event.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Analysis of UFLS program performance following an actual underfrequency event below the UFLS set point(s) was incomplete in one or more elements in Reliability Standard PRC-009-0_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Analysis of UFLS program performance following an actual underfrequency event below the UFLS set point(s) was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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4. 30-day posting before board adoption.	January 8, 2005–February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Technical Assessment of the Design and Effectiveness of Undervoltage Load Shedding Program.**

2. **Number:** PRC-010-0 (068.3)

3. **Purpose:** Provide System preservation measures in an attempt to prevent system voltage collapse or voltage instability by implementing an Undervoltage Load Shedding (UVLS) program. ~~requiring end users of electricity on the Bulk Electric System to drop Loads.~~

4. **Applicability:**

   4.1. Load-Serving Entity that operates a~~n~~ UVLS program

   4.2. Transmission Owner that owns a UVLS program

   4.3. Transmission Operator that operates a UVLS program

   4.4. Distribution Provider that owns or operates a UVLS program

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. The Load-Serving Entity, Transmission Owner~~s~~, Transmission Operator, and Distribution Provider that owns or operates a UVLS program~~s~~ shall periodically (at least every five years or as required by changes in system conditions) conduct and document an ~~technical~~ assessment of the effectiveness of the UVLS program~~s~~. This assessment shall be conducted with the associated Transmission Planner(s) and Planning Authority(ies).

R1.1. This assessment shall include, but is not limited to:

R1.1.1. Coordination of the UVLS programs with other protection and control systems in the Region and with other Regional Reliability Organizations, as appropriate.

R1.1.2. Simulations that demonstrate that the UVLS programs performance is consistent with Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0.

R1.1.3. A review of the voltage set points and timing.

R2. The Load-Serving Entity, Transmission Owner~~s~~, Transmission Operator, and Distribution Provider that owns or operates a ~~Undervoltage Load Shedding~~UVLS program~~s~~ shall provide documentation of its current UVLS program~~'s~~ ~~technical~~ assessment to ~~the appropriate~~its Regional Reliability Organization~~s~~ and NERC on request (30 calendar days).

C. Measures

M1. ~~The~~Each ~~Load-Serving Entity,~~ Transmission Owner's~~,~~ ~~Transmission Operator,~~ and Distribution Provider's UVLS ~~that owns or operates Undervoltage Load Shedding~~ program~~s~~ shall ~~-~~includes the elements identified in Reliability Standard PRC-010-0_R1.

M2. ~~The~~ Each Load-Serving Entity, Transmission Owner~~s~~, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall have evidence it provided documentation of ~~its~~ its current UVLS program~~'s~~ ~~technical~~ assessment to ~~the~~ its Regional Reliability Organization~~s~~ and NERC as specified in Reliability Standard PRC-010-0_R2.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations. Each Regional Reliability Organization shall report compliance and violations to NERC via the NERC Compliance Reporting process.

1.2. Compliance Monitoring Period and Reset Timeframe

~~Technical~~ Assessments every five years or as required by System changes.

Current ~~technical~~ ~~Assessment~~ assessment on request (30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: A ~~technical~~n assessment of the UVLS program~~s~~ did not address one of the three requirements listed in Reliability Standard PRC-010-0_R1.1 or an ~~technical~~ assessment of the UVLS program~~s~~ was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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Development Steps Completed:

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Description of Current Draft:

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Future Development Plan:

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1. Seek endorsement of NERC technical committees.	November 9-11, 2004
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4. 30-day posting before board adoption.	January 8, 2005–February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Undervoltage Load Shedding System Maintenance and Testing**

2. **Number:** PRC-011-0 (068.4)

3. **Purpose:** Provide system preservation measures in an attempt to prevent system voltage collapse or voltage instability by implementing an Undervoltage Load Shedding (UVLS) program. ~~requiring end users of electricity on the Bulk Electric System to drop Loads.~~

4. **Applicability:**

   ~~4.2.~~4.1. Transmission Owner that owns a UVLS system

   ~~4.3.~~4.2. Distribution Provider that owns a UVLS system

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. The ~~Load-Serving Entity,~~ Transmission Owner~~,~~ and Distribution Provider that owns a~~n~~ UVLS system shall have a UVLS ~~system~~ equipment maintenance and testing program~~(s)~~ in place. This ~~e~~ program~~(s)~~ shall include:

R1.1. The UVLS system identification which shall include but is not limited to:

R1.1.1. Relays.

R1.1.2. Instrument transformers.

R1.1.3. Communications systems, where appropriate.

R1.1.4. Batteries.

R1.2. Documentation of maintenance and testing intervals and their basis.

R1.3. Summary of testing procedure.

R1.4. Schedule for system testing.

R1.5. Schedule for system maintenance.

R1.6. Date last tested/maintained.

R2. The ~~Load-Serving Entity,~~ Transmission Owner~~,~~ and Distribution Provider that owns a UVLS system shall provide documentation of ~~the~~ its UVLS equipment maintenance and testing program and ~~its~~ the implementation of that UVLS equipment maintenance and testing program to ~~the appropriate~~its Regional Reliability Organization~~s~~ and NERC on request (within 30 calendar days).

C. Measures

M1. ~~The~~Each ~~Load-Serving Entity,~~ Transmission Owner~~,~~ and Distribution Provider that owns a~~n~~ UVLS system shall have documentation that ~~its~~its UVLS equipment maintenance and testing program conforms with Reliability Standard PRC-011-0_R1.

M2. ~~The~~Each ~~Load-Serving Entity,~~ Transmission Owner~~,~~ and Distribution Provider that owns a~~n~~ UVLS system shall have evidence it provided documentation of its UVLS equipment maintenance and testing program and ~~its~~ the implementation of that UVLS equipment maintenance and testing program~~implementation~~ as specified in Reliability Standard PRC-011-0_R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (30 calendar days~~.~~).

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

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

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

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

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

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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4. 30-day posting before board adoption.	January 8, 2005–February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Special Protection System Review Procedure**

2. **Number:** PRC-012-0 (069.1)

3. **Purpose:** To ensure that all Special Protection Systems (SPS~~s~~) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers~~(s)~~ that uses or is planning to use an SPS shall have a documented Regional Reliability Organization SPS review procedure to ensure ~~the~~ that SPSs ~~complies~~ comply with Regional ~~Reliability Organization~~ criteria and NERC Reliability Standards. The Regional ~~Reliability Organization~~ SPS review procedure shall include:

R1.1. Description of the process for submitting a proposed SPS for Regional Reliability Organization review.

R1.2. Requirements to provide data that describes design, operation, and modeling of an SPS.

R1.3. Requirements to demonstrate that the 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 in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.

R1.4. Requirements to demonstrate that the inadvertent operation of an SPS shall meet the same performance requirement (TPL-001-0, TPL-002-0, and TPL-003-0) as that required of the contingency for which it was designed, and not exceed TPL-003-0.

R1.5. Requirements to demonstrate the proposed SPS will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures.

R1.6. Regional Reliability Organization definition of misoperation.

R1.7. Requirements for analysis and documentation of corrective action plans for all SPS misoperations.

R1.8. Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization's review procedure and the process for Regional Reliability Organization approval of the procedure.

R1.9. Determination, as appropriate, of maintenance and testing requirements.

R2. The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of ~~the Regional Reliability Organization’~~its~~s~~ SPS review procedure on request (within 30 calendar days).

C. Measures

M1. The Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Provider using or planning to use an SPS shall have a documented Regional ~~Reliability Organization~~ review procedure as defined in Reliability Standard PRC-012-0_R1.

M2. The Regional Reliability Organization shall have evidence it provided affected Regional Reliability Organizations and NERC with documentation of its SPS review procedure on request (within 30 calendar days).

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: ~~Unaffiliated Third Party~~NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Documentation of the Regional Reliability Organization's procedure is missing one of the items listed in Reliability Standard PRC-012-0_R1.

2.2. Level 2: Documentation of the Regional Reliability Organization's procedure is missing two of the items listed in Reliability Standard PRC-012-0_R1.

2.3. Level 3: Documentation of the Regional Reliability Organization's procedure is missing three of the items listed in Reliability Standard PRC-012-0_R1.

2.4. Level 4: Documentation of the Regional Reliability Organization's procedure was not provided or is missing four or more of the items listed in Reliability Standard PRC-012-0_R1.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Special Protection System Database.**

2. **Number:** PRC-013-0 (69.2)

3. **Purpose:** To ensure that all Special Protection Systems (SPSs) are properly designed, meet performance requirements, and are coordinated with other protection systems. ~~To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.~~

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Proposed Effective Date:** April 1~~February 8~~, 2005

B. Requirements

R1. ~~A~~ The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with an SPS installed shall maintain an SPS database. The database shall include the following types of information:

R1.1. Design Objectives ~~–~~ — Contingencies and system conditions for which the SPS was designed,

R1.2. Operation ~~–~~ — The actions taken by the SPS in response to Disturbance conditions, and

R1.3. Modeling ~~–~~ — Information on detection logic or relay settings that control operation of the SPS.

R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).

C. Measures

M1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Providers with an SPS installed, shall have an SPS database as defined in PRC-013-0_R1 of this Reliability Standard.

M2. The Regional Reliability Organization shall have evidence it provided documentation of its database or the information therein, to affected Regional Reliability Organization(s) and NERC on request (within 30 calendar days).

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

Compliance Monitor: ~~Unaffiliated Third Party~~NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: The Regional Reliability Organization's database is missing one of the items listed in Reliability Standard PRC-013-0_R1.

2.2. Level 2: The Regional Reliability Organization's database is missing two of the items listed in Reliability Standard PRC-013-9_R1.

2.3. Level 3: Not applicable.

2.4. Level 4: The Regional Reliability Organization's database was not provided or is missing all of the elements listed in Reliability Standard PRC-013-0_R1.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Special Protection System Assessment**

2. **Number:** PRC-014-0 (069.3)

3. **Purpose:** To ensure that all Special Protection Systems (SPS~~s~~) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all SPSs installed in its Region at least once every five years for compliance with NERC Reliability Standards and Regional criteria.

R2. The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all SPSs installed in its Region to affected Regional Reliability Organizations~~liability Authorities~~ or NERC~~,~~ on request (within 30 calendar days).

R3. The documentation of the Regional Reliability Organization's SPS assessment shall include the following elements:

R3.1. Identification of group conducting the assessment and the date the assessment was performed.

R3.2. Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed.

R3.3. Identification of SPSs that were found not to comply with NERC ~~Standards~~ standards and Regional Reliability Organization criteria.

R3.4. Discussion of any coordination problems found between a SPS and other protection and control systems.

R3.5. Provide corrective action plans for non-compliant SPSs.

C. Measures

M1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all SPSs installed in its Region at least once every five years for compliance with NERC ~~Standards~~ standards and Regional criteria.

M2. The Regional Reliability Organization shall provide either a summary report or a detailed report of this assessment to affected Regional Reliability Organizations or NERC~~,~~ on request (within 30 calendar days).

M3. The Regional Reliability Organization's documentation of the SPS assessment shall include all elements as defined in Reliability Standard PRC-014-0_R3.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

Compliance Monitor: ~~Unaffiliated Third Party~~NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: The summary (or detailed) Regional ~~Reliability Organization~~ SPS assessment is missing one of the items listed in Reliability Standard PRC-014-0_R3.

2.2. Level 2: The summary (or detailed) Regional ~~Reliability Organization~~ SPS assessment is missing two of the items listed in Reliability Standard PRC-014-0_3.

2.3. Level 3: The summary (or detailed) Regional ~~Reliability Organization's summary (or detailed) Regional Reliability Organization~~ SPS assessment is missing three of the items listed in Reliability Standard PRC-014-0_R3.

2.4. Level 4: The summary (or detailed) Regional ~~Reliability Organization's summary (or detailed) Regional Reliability Organization~~ SPS assessment is missing more than three of the items listed in Reliability Standard PRC-014-0_R3 or was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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Development Steps Completed:

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4. 30-day posting before board adoption.	January 8, 2005–February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Special Protection System Data and Documentation**

2. **Number:** PRC-015-0 (069.4)

3. **Purpose:** To ensure that all Special Protection Systems (SPS~~s~~) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are ~~Analyzed~~ analyzed and corrected.

4. **Applicability:**

   4.1. Transmission Owner that owns an SPS

   4.2. Generator Owner that owns an SPS

   4.3. Distribution Provider that owns an SPS

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall maintain a list of and provide data for existing and proposed SPSs as specified in Reliability Standard PRC-013-0_R1.

R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it reviewed new or functionally modified SPSs in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-0_R1 prior to being placed in service.

R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of SPS data and the results of Studies that show compliance of new or functionally modified SPSs with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC~~,~~ on request (within 30 calendar days).

C. Measures

M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it maintains a list of and provides data for existing and proposed SPSs as defined in Reliability Standard PRC-013-0_R1.

M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it reviewed new or functionally modified SPSs in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-0_R1 prior to being placed in service.

M3. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it provided documentation of SPS data and the results of ~~Studies~~ studies that show compliance of new or functionally modified SPSs with NERC ~~Standards~~ standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC~~,~~ on request (within 30 calendar days).

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days~~.~~).

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: SPS owners provided SPS data, but was incomplete according to the Regional Reliability Organization SPS ~~Database~~ database requirements.

2.2. Level 2: SPS owners provided results of ~~Studies~~ studies that show compliance of new or functionally modified SPSs with the NERC Planning Standards and Regional Reliability Organization criteria, but were incomplete according to the Regional Reliability Organization procedures for Reliability Standard PRC-012-0_R1.

2.3. Level 3: Not applicable.

2.4. Level 4: No SPS data was provided in accordance with Regional Reliability Organization SPS database requirements for Standard PRC-012-0_R1, or the results of ~~Studies~~ studies that show compliance of new or functionally modified SPSs with the NERC Reliability Standards and Regional Reliability Organization criteria were not provided in accordance with Regional Reliability Organization procedures for Reliability Standard PRC-012-0_R1.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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4. 30-day posting before board adoption.	January 8, 2005–February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Special Protection System Misoperations**

2. **Number:** PRC-016-0 (069.5)

3. **Purpose:** To ensure that all Special Protection Systems (SPS~~s~~) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.

4. **Applicability:**

   4.1. Transmission Owner that owns an SPS

   4.2. Generator Owner that owns an SPS

   4.3. Distribution Provider that owns an SPS

5. **Proposed Effective Date:** April 1~~February 8~~, 2005

B. Requirements

R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall analyze its SPS operations and maintain a record of all misoperations in accordance with the Regional SPS review ~~Reliability Organization~~ procedure~~s~~ specified in Reliability Standard PRC-012-0_R1.

R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall take corrective actions to avoid future misoperations.

R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the misoperation analyses and the corrective action plans to ~~the affected~~its Regional Reliability Organization and NERC~~,~~ on request (within 90 calendar days).

C. Measures

M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it analyzed SPS operations and ~~maintains~~ maintained a record of all misoperations in accordance with the Regional SPS review ~~Reliability Organization~~ procedure~~s~~ specified in Reliability Standard PRC-016-0_R1.

M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it took corrective actions to avoid future misoperations.

M3. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it provided documentation of the misoperation analyses and the corrective action plans to the affected Regional Reliability Organization and NERC~~,~~ on request (within 90 calendar days).

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Timeframe

   On request [within 90 calendar days of the incident or on request (within 30 calendar days) if requested more than 90 calendar days after the incident.]

   1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Documentation of SPS misoperations is complete but documentation of corrective actions taken for all identified SPS misoperations is incomplete.

2.2. Level 2: Documentation of corrective actions taken for SPS misoperations is complete but documentation of SPS misoperations is incomplete.

2.3. Level 3: Documentation of SPS misoperations and corrective actions is incomplete.

2.4. Level 4: No documentation of SPS misoperations or corrective actions.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Special Protection System Maintenance and Testing**

2. **Number:** PRC-017-0 (069.6)

3. **Purpose:** To ensure that all Special Protection Systems (SPS~~s~~) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.

4. **Applicability:**

   4.1. Transmission Owner that owns an SPS

   4.2. Generator Owner that owns an SPS

   4.3. Distribution Provider that owns an SPS

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have a system maintenance and testing program(s) in place. The program(s) shall include:

R1.1. SPS identification shall include but is not limited to:

R1.1.1. Relays.

R1.1.2. Instrument transformers.

R1.1.3. Communications systems, where appropriate.

R1.1.4. Batteries.

R1.2. Documentation of maintenance and testing intervals and their basis.

R1.3. Summary of testing procedure.

R1.4. Schedule for system testing.

R1.5. Schedule for system maintenance.

R1.6. Date last tested/maintained.

R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).

C. Measures

M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have a system maintenance and testing program(s) in place that includes all items in Reliability Standard PRC-017-0_R1.

M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it provided documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

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

Timeframe:
On request (30 calendar days.)

1.2. Compliance Monitoring Period and Reset Timeframe

Compliance Monitor: Regional Reliability Organization.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

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

2.2. Level 2: Complete documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.

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

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

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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A. Introduction

1. **Title:** **Establish, Maintain, and Document a Regional Blackstart Capability Plan.**

2. **Number:** EOP-007-0 (070.1)

3. **Purpose:** A system Blackstart Capability Plan (BCP) is necessary to ensure that the quantity and location of system blackstart generators are sufficient and that they can perform their expected functions as specified in overall coordinated Regional System Restoration Plans (SRP~~s~~).

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization shall establish and maintain a system BCP, as part of an overall coordinated Regional SRP. The ~~overall~~ Regional SRP shall include requirements for verification through analysis how system blackstart generating units shall perform their intended functions and shall be sufficient to meet SRP expectations. The Regional Reliability Organization shall coordinate with and among other Regional Reliability Organizations as appropriate in the development of its BCP. The BCP shall include:

R1.1. A requirement to have a database that contains all blackstart generators[1] designated for use in an SRP within the respective areas. This database shall be updated on an annual basis. The database shall include the name, location, megawatt capacity, type of unit, latest date of test, and starting method.

R1.2. A requirement to demonstrate that blackstart units perform their intended functions as required in the ~~Reliability Authority's~~ Regional SRP. This requirement can be met through either ~~through~~ simulation or testing. The BCP must consider the availability of designated BCP units and initial transmission switching requirements.

R1.3. Blackstart unit testing requirements including, but not limited to:

R1.3.1. Testing frequency (minimum of one third of the units each year).

R1.3.2. Type of test required, including the requirement to start when isolated from the system.

R1.3.3. Minimum duration of tests.

R1.4. A requirement to review and update the Regional BCP at least every five years.

R2. The Regional Reliability Organization shall provide documentation of its system BCPs to NERC within 30 calendar days of a request.

C. Measures

M1. The Regional Reliability Organization's BCP shall include all four of the requirements in Reliability Standard EOP-007-0_R1.

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[1] 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 Regional Reliability Organization in accordance with the Regional ~~blackstart~~ Blackstart Capability?plan or that unit will no longer be considered a blackstart unit.

M2. The Regional Reliability Organization shall have evidence it provided its BCP in accordance with Reliability Standard EOP-007-0_R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: ~~Unaffiliated Third Party~~NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

Current Regional BCP: on request (30 calendar days).

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: The Regional Reliability Organization's Blackstart ~~generating unit~~ Capability Plan was incomplete in one of the four requirements defined above in Reliability Standard EOP-007-0_R1.

2.3. Level 3: Not applicable.

2.4. Level 4: The Regional Reliability Organization's Blackstart ~~generating unit~~ Capability Plan was not provided (Reliability Standard EOP-007-0_R1), or was incomplete in two or more of the four requirements defined above in Reliability Standard EOP-007-0_R1.

E. Regional Differences

1. None.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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4. 30-day posting before board adoption.	January 8, 2005–February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Documentation of Blackstart Generating Unit Test Results**

2. **Number:** EOP-009-0 (070.4)

3. **Purpose:** A system Blackstart Capability Plan (BCP) is necessary to ensure that the quantity and location of system blackstart generators are sufficient and that they can perform their expected functions as specified in overall coordinated Regional System Restoration Plans.

4. **Applicability:**

   4.1. Generator Operator

   4.2. Generator Owner

5. **Proposed Effective Date:** ~~February 8~~April 1, 2005

B. Requirements

R1. The Generator Operator of each blackstart generating unit shall test the startup and operation of each system blackstart generating unit identified in the BCP as required in the Regional BCP (Reliability Standard EOP-007-0_R1). Testing records shall include the dates of the tests, the duration of the tests, and an indication of whether the tests met Regional BCP requirements.

R2. The Generator Owner or Generator Operator shall provide documentation of the test results of the startup and operation of each blackstart generating unit to the Regional Reliability Organizations and upon request to NERC.

C. Measures

M1. The Generator Operator shall have evidence it provided the test results specified in Reliability Standard EOP-009-0R1 as specified in Reliability Standard EOP-009-0_R2.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Timeframe

   Current test results: to the Regional Reliability Organization and upon request to NERC (30 calendar days).

   1.3. Data Retention

   None specified.

   1.4. Additional Compliance Information

   None

2. **Levels of Non-Compliance**

   2.1. Level 1: Startup and operation testing of each blackstart generating unit was performed, but the documentation was incomplete.

   2.2. Level 2: Not applicable.

   2.3. Level 3: Startup and operation testing of a blackstart generating unit was only partially performed.

2.4. **Level 4:** Startup and operation testing of each blackstart generating unit was not performed.

E. Regional Differences

1. None identified.

Version History

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Standard Development Roadmap

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5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. **Title:** **Vegetation Management Program.**

2. **Number:** FAC-003-0 (072.1)

3. **Purpose:** To ensure that Transmission Owners have a vegetation management program to prevent transmission line contact with vegetation, and to ensure that certain vegetation-related outages are reported to the appropriate Regional Reliability Organization.

4. **Applicability:**

   4.1. Transmission Owner

5. **Proposed Effective Date:** April 1~~February 8~~, 2005

B. Requirements

R1. Each Transmission Owner shall have a vegetation management program to prevent ~~Transmission~~ transmission line contact with vegetation. The vegetation management program shall include the following three elements:

R1.1. Inspection requirements.

R1.2. Trimming clearances.

R1.3. Annual work plan.

R2. Each Transmission Owner shall report to its Regional Reliability Organization –all vegetation-related outages on transmission circuits 200 kV and higher and any other lower voltage lines designated by the Regional Reliability Organization –to be critical to the reliability of the electric system.

C. Measures

M1. The Transmission Owner's vegetation management program documentation contains the following elements:

M1.1 Inspection requirements.

M1.2 Trimming clearances.

M1.3 Annual work plan.

M2. The Transmission Owner shall have evidence it performs vegetation program maintenance in the annual work plan according to the requirements and procedures contained in the program.

M3. The Transmission Owner shall have evidence it reported all vegetation-related transmission line trips on lines of 200kV or higher and any other lower voltage lines designated by the Regional Reliability Organization to be critical to the reliability of the electric system.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

Compliance ~~Monitor~~monitor: Regional Reliability Organization. Each Regional Reliability Organization –shall report compliance and violations to NERC via the NERC ~~Compliance~~ compliance ~~Reporting~~ reporting process.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar quarter.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

1.4.1. The Transmission Owner is non-compliant if:

1.4.1.1 Vegetation-related outages occurred and were not reported during a one-month period.

1.4.1.2 The vegetation management plan is ~~found to be not~~ incomplete.

1.4.1.3 The Transmission Owner did not perform necessary maintenance described in the annual work plan as reported via self-certification.

2. Levels of Non-Compliance

2.1. Full Compliance:

2.1.1 Three-year Audit:

2.1.1.1 The vegetation management program is fully documented and contains all three elements listed in Reliability Standard FAC-003-0_R1.

2.1.2 Self-Certification

2.1.2.1 The Transmission Owner performed all maintenance as described in the annual work plan.

2.1.3 Periodic Reporting

2.1.3.1 All vegetation-related transmission line outages of 200kV or higher and any other lower voltage lines designated by the Regional Reliability Organization to be critical to the ~~Reliability~~ reliability of the electric system are reported during a calendar quarter.

2.1.3.2 All outages shall be reported where the cause of the outage is the line faulting due to contact with vegetation, except:

2.1.3.2.1 Multiple outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number of outages within a 24-hour period.

2.1.3.2.2 A single trip followed by a successful automatic reclosure within a 24-hour period shall not be a reportable outage.

2.2. Level 1: None specified.

2.3. Level 2: None specified.

2.4. Level 3: None specified.

2.5. Level 4: None specified.

E. Regional Differences

1. None.

Version History

Version	Date	Action	Change Tracking