

**Exhibit B**

**Reliability Standard submitted for Approval**

**A. Introduction**

- 1. Title:** Facility Connection Requirements
- 2. Number:** FAC-001-1
- 3. Purpose:** To avoid adverse impacts on reliability, Transmission Owners and Generator Owners must establish Facility connection and performance requirements.
- 4. Applicability:**
  - 4.1.** Transmission Owner
  - 4.2.** Applicable Generator Owner
    - 4.2.1** Generator Owner with an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems.
- 5. Effective Date:**
  - 5.1.** In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner and Regional Entity become effective upon Board of Trustees' adoption.
  - 5.2.** In those jurisdictions where regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities. In those jurisdictions where no regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after Board of Trustees' adoption.

**B. Requirements**

- R1.** The Transmission Owner shall document, maintain, and publish Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, 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:
  - 1.1.** Generation Facilities,
  - 1.2.** Transmission Facilities, and
  - 1.3.** End-user Facilities

*[VRF – Medium]*
- R2.** Each applicable Generator Owner shall, within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems (under FAC-002-1), document and publish its Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, subregional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements.

*[VRF – Medium]*

- R3.** Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) shall address the following items in its Facility connection requirements:
- 3.1.** Provide a written summary of its plans to achieve the required system performance as described in Requirements R1 or R2 throughout the planning horizon:
- 3.1.1.** Procedures for coordinated joint studies of new Facilities and their impacts on the interconnected Transmission systems.
  - 3.1.2.** Procedures for notification of new or modified Facilities to others (those responsible for the reliability of the interconnected Transmission systems) as soon as feasible.
  - 3.1.3.** Voltage level and MW and MVAR capacity or demand at point of connection.
  - 3.1.4.** Breaker duty and surge protection.
  - 3.1.5.** System protection and coordination.
  - 3.1.6.** Metering and telecommunications.
  - 3.1.7.** Grounding and safety issues.
  - 3.1.8.** Insulation and insulation coordination.
  - 3.1.9.** Voltage, Reactive Power, and power factor control.
  - 3.1.10.** Power quality impacts.
  - 3.1.11.** Equipment Ratings.
  - 3.1.12.** Synchronizing of Facilities.
  - 3.1.13.** Maintenance coordination.
  - 3.1.14.** Operational issues (abnormal frequency and voltages).
  - 3.1.15.** Inspection requirements for existing or new Facilities.
  - 3.1.16.** Communications and procedures during normal and emergency operating conditions.

*[VRF – Medium]*

- R4.** 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, the Regional Entity, and ERO on request (five business days).

*[VRF – Medium]*

**C. Measures**

- M1.** The Transmission Owner shall make available (to its Compliance Enforcement Authority) evidence that it met all the requirements stated in Requirement R1.

- M2.** Each Generator Owner that has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the interconnected Transmission systems shall make available (to its Compliance Enforcement Authority) evidence that it met all requirements stated in Requirement R2.
- M3.** Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) shall make available (to its Compliance Enforcement Authority) evidence that it met all requirements stated in Requirement R3.
- M4.** The Transmission Owner shall make available (to its Compliance Enforcement Authority) evidence that it met all the requirements stated in Requirement R4.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

Compliance Monitor: Regional Entity

**1.2. Compliance Monitoring and Enforcement Processes:**

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

**1.3. Data Retention**

The Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Owner shall retain evidence of Requirement R1, Measure M1, Requirement R3, Measure M3, and Requirement R4, Measure M4 from its last audit.

The Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain evidence of Requirement R2, Measure M2, and Requirement R3, Measure M3 from its last audit.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Additional Compliance Information**

None.



2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Not Applicable.	<p>The Transmission Owner failed to do one of the following:</p> <p>Document or maintain or publish Facility connection requirements as specified in the Requirement</p> <p>OR</p> <p>Failed to include one (1) of the components as specified in R1.1, R1.2 or R1.3.</p>	<p>The Transmission Owner failed to do one of the following:</p> <p>Failed to include (2) of the components as specified in R1.1, R1.2 or R1.3</p> <p>OR</p> <p>Failed to document or maintain or publish its Facility connection requirements as specified in the Requirement <b>and</b> failed to include one (1) of the components as specified in R1.1, R1.2 or R1.3.</p>	The Transmission Owner did not develop Facility connection requirements.
R2	The Generator Owner failed to document and publish Facility connection requirements until more than 45 calendar days but less than or equal to 60 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the interconnected Transmission systems.	The Generator Owner failed to document and publish Facility connection requirements until more than 60 calendar days but less than or equal to 70 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the interconnected Transmission systems.	The Generator Owner failed to document and publish Facility connection requirements until more than 70 calendar days but less than or equal to 80 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the interconnected Transmission systems.	The Generator Owner failed to document and publish Facility connection requirements until more than 80 days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the interconnected Transmission systems.
R3	The responsible entity’s Facility connection	The responsible entity’s Facility connection	The responsible entity’s Facility connection	The responsible entity’s Facility connection

	requirements failed to address one of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.	requirements failed to address two of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.	requirements failed to address three of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.	requirements failed to address four or more of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.
R4	The responsible entity made the requirements available more than five business days but less than or equal to 10 business days after a request.	The responsible entity made the requirements available more than 10 business days but less than or equal to 20 business days after a request.	The responsible entity made the requirements available more than 20 business days less than or equal to 30 business days after a request.	The responsible entity made the requirements available more than 30 business days after a request.

**E. Regional Differences**

1. None identified.

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1		Added requirements for Generator Owner and brought overall standard format up to date.	Revision under Project 2010-07
1	February 9, 2012	Adopted by the Board of Trustees	

**B.A. Introduction**

1. **Title:** Facility Connection Requirements
2. **Number:** FAC-001-~~0~~1
3. **Purpose:**- To avoid adverse impacts on reliability, Transmission Owners and Generator Owners must establish facilityFacility connection and performance requirements.
4. **Applicability:**
  - 4.1. Transmission Owner
  - 4.2. Applicable Generator Owner
    - 4.2.1 Generator Owner with an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems.
5. **Effective Date:**—~~April 1, 2005~~
  - 5.1. In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner and Regional Entity become effective upon Board of Trustees' adoption.
  - 5.2. In those jurisdictions where regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities. In those jurisdictions where no regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after Board of Trustees' adoption.

**C.B. Requirements**

- R1.** The Transmission Owner shall document, maintain, and publish facilityFacility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Reliability OrganizationEntity, subregional, Power Pool, and individual Transmission Owner planning criteria and facilityFacility connection requirements. The Transmission Owner's facilityFacility connection requirements shall address connection requirements for:
- R1.1.1.1.** Generation facilitiesFacilities,
  - R1.2.1.2.** Transmission facilitiesFacilities, and
  - R1.3.1.3.** End-user facilitiesFacilities
- ~~R2.~~** ~~The Transmission Owner's facility connection requirements shall address, but are not limited to, the following items:~~
- ~~[VRF – Medium]~~
- R2.** Each applicable Generator Owner shall, within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems (under FAC-002-1), document and publish its Facility connection requirements to

ensure compliance with NERC Reliability Standards and applicable Regional Entity, subregional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements.

*[VRF – Medium]*

**R3.** Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) shall address the following items in its Facility connection requirements:

**R2.1.3.1.** Provide a written summary of its plans to achieve the required system performance as described ~~above~~ in Requirements R1 or R2 throughout the planning horizon:

**R2.1.1.3.1.1.** Procedures for coordinated joint studies of new ~~faeilities~~Facilities and their impacts on the interconnected ~~transmission~~Transmission systems.

**R2.1.2.3.1.2.** Procedures for notification of new or modified ~~faeilities~~Facilities to others (those responsible for the reliability of the interconnected ~~transmission~~Transmission systems) as soon as feasible.

**R2.1.3.3.1.3.** Voltage level and MW and MVAR capacity or demand at point of connection.

**R2.1.4.3.1.4.** Breaker duty and surge protection.

**R2.1.5.3.1.5.** System protection and coordination.

**R2.1.6.3.1.6.** Metering and telecommunications.

**R2.1.7.3.1.7.** Grounding and safety issues.

**R2.1.8.3.1.8.** Insulation and insulation coordination.

**R2.1.9.3.1.9.** Voltage, Reactive Power, and power factor control.

**R2.1.10.3.1.10.** Power quality impacts.

**R2.1.11.3.1.11.** Equipment Ratings.

**R2.1.12.3.1.12.** Synchronizing of ~~faeilities~~Facilities.

**R2.1.13.3.1.13.** Maintenance coordination.

**R2.1.14.3.1.14.** Operational issues (abnormal frequency and voltages).

**R2.1.15.3.1.15.** Inspection requirements for existing or new ~~faeilities~~Facilities.

**R2.1.16.3.1.16.** Communications and procedures during normal and emergency operating conditions.

*[VRF – Medium]*

**R3-R4.** The Transmission Owner shall maintain and update its ~~faeility~~Facility connection requirements as required. - The Transmission Owner shall make documentation of these requirements available to the users of the transmission system, the Regional ~~Reliability Organization~~Entity, and ~~NERC~~ERO on request (five business days).

[VRF – Medium]

**D.C. Measures**

- M1.** The Transmission Owner shall make available (to its Compliance ~~Monitor~~) for inspection Enforcement Authority evidence that it met all the requirements stated in Reliability Standard FAC-001-0-Requirement R1.
- M2.** ~~The~~Each Generator Owner that has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission ~~Owners~~systems shall make available (to its Compliance ~~Monitor~~) for inspection Enforcement Authority evidence that it met all requirements stated in Reliability Standard FAC-001-0-Requirement R2.
- M3.** ~~The~~Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) shall make available (to its Compliance ~~Monitor~~) for inspection Enforcement Authority evidence that it met all ~~the~~ requirements stated in Reliability Standard FAC-001-0-R3 Requirement R3.
- M3.M4.** The Transmission Owner shall make available (to its Compliance Enforcement Authority) evidence that it met all the requirements stated in Requirement R4.

**E.D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance ~~Monitoring Responsibility~~ Enforcement Authority**

Compliance Monitor: Regional ~~Reliability Organization~~ Entity

**1.2. Compliance Monitoring ~~Period~~ and ~~Reset Timeframe~~ Enforcement Processes:**

~~On request (five business days):~~

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

**1.3. Data Retention**

~~None specified:~~

The Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Owner shall retain evidence of Requirement R1, Measure M1, Requirement R3, Measure M3, and Requirement R4, Measure M4 from its last audit.

The Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain evidence of Requirement R2, Measure M2, and Requirement R3, Measure M3 from its last audit.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Additional Compliance Information**

None.

**2. Violation Severity 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.~~

<u>R #</u>	<u>Lower VSL</u>	<u>Moderate VSL</u>	<u>High VSL</u>	<u>Severe VSL</u>
<u>R1</u>	<u>Not Applicable.</u>	<u>The Transmission Owner failed to do one of the following:</u>  <u>Document or maintain or publish Facility connection requirements as specified in the Requirement</u>  <u>OR</u>  <u>Failed to include one</u>	<u>The Transmission Owner failed to do one of the following:</u>  <u>Failed to include (2) of the components as specified in R1.1, R1.2 or R1.3</u>  <u>OR</u>  <u>Failed to document or maintain or publish its Facility connection</u>	<u>The Transmission Owner did not develop Facility connection requirements.</u>

		<u>(1) of the components as specified in R1.1, R1.2 or R1.3.</u>	<u>requirements as specified in the Requirement and failed to include one (1) of the components as specified in R1.1, R1.2 or R1.3.</u>	
<u>R2</u>	<u>The Generator Owner failed to document and publish Facility connection requirements until more than 45 calendar days but less than or equal to 60 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems.</u>	<u>The Generator Owner failed to document and publish Facility connection requirements until more than 60 calendar days but less than or equal to 70 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems.</u>	<u>The Generator Owner failed to document and publish Facility connection requirements until more than 70 calendar days but less than or equal to 80 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems.</u>	<u>The Generator Owner failed to document and publish Facility connection requirements until more than 80 days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems.</u>
<u>R3</u>	<u>The responsible entity's Facility connection requirements failed to address one of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.</u>	<u>The responsible entity's Facility connection requirements failed to address two of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.</u>	<u>The responsible entity's Facility connection requirements failed to address three of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.</u>	<u>The responsible entity's Facility connection requirements failed to address four or more of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.</u>
<u>R4</u>	<u>The responsible entity made the requirements available more than five business days but less than or equal to 10 business days after a request.</u>	<u>The responsible entity made the requirements available more than 10 business days but less than or equal to 20 business days after a request.</u>	<u>The responsible entity made the requirements available more than 20 business days less than or equal to 30 business days after a request.</u>	<u>The responsible entity made the requirements available more than 30 business days after a request.</u>

P.E. Regional Differences

1. None identified.

### Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
<u>1</u>		<u>Added requirements for Generator Owner and brought overall standard format up to date.</u>	<u>Revision under Project 2010-07</u>
<u>1</u>	<u>February 9, 2012</u>	<u>Adopted by the Board of Trustees</u>	

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## Effective Dates

There are two effective dates associated with this standard.

The first effective date allows Generator Owners time to develop documented maintenance strategies or procedures or processes or specifications as outlined in Requirement R3.

In those jurisdictions where regulatory approval is required, Requirement R3 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

The second effective date allows entities time to comply with Requirements R1, R2, R4, R5, R6, and R7.

In those jurisdictions where regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 become effective on the first day of the first calendar quarter two years following Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.
2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.

3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.
4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.
5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

## A. Introduction

1. **Title:** Transmission Vegetation Management
2. **Number:** FAC-003-3
3. **Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

### 4. Applicability

#### 4.1. Functional Entities:

##### 4.1.1. Applicable Transmission Owners

4.1.1.1 Transmission Owners that own Transmission Facilities defined in 4.2.

##### 4.1.2 Applicable Generator Owners

4.1.2.1 Generator Owners that own generation Facilities defined in 4.3

#### 4.2. **Transmission Facilities:** Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal<sup>1</sup>, state, provincial, public, private, or tribal entities:

4.2. 1 Each overhead transmission line operated at 200kV or higher.

4.2.2 Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.

4.2.3 Each overhead transmission line operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

4.2.4 Each overhead transmission line identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

#### 4.3. **Generation Facilities:** Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal<sup>2</sup>, state, provincial, public, private, or tribal entities:

4.3.1 Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner’s Facility or (2) do not have a clear line

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<sup>1</sup> EPAAct 2005 section 1211c: “Access approvals by Federal agencies.”

<sup>2</sup> *Id.*

of sight<sup>3</sup> from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and are:

**4.3.1.1** Operated at 200kV or higher; or

**4.3.1.2** Operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator; or

**4.3.1.3** Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

Enforcement:

The Requirements within a Reliability Standard govern and will be enforced. The Requirements within a Reliability Standard define what an entity must do to be compliant and binds an entity to certain obligations of performance under Section 215 of the Federal Power Act. Compliance will in all cases be measured by determining whether a party met or failed to meet the Reliability Standard Requirement given the specific facts and circumstances of its use, ownership or operation of the bulk power system.

Measures provide guidance on assessing non-compliance with the Requirements. Measures are the evidence that could be presented to demonstrate compliance with a Reliability Standard Requirement and are not intended to contain the quantitative metrics for determining satisfactory performance nor to limit how an entity may demonstrate compliance if valid alternatives to demonstrating compliance are available in a specific case. A Reliability Standard may be enforced in the absence of specified Measures.

Entities must comply with the "Compliance" section in its entirety, including the Administrative Procedure that sets forth, among other things, reporting requirements.

The "Guideline and Technical Basis" section, the Background section and text boxes with "Examples" and "Rationale" are provided for informational purposes. They are designed to convey guidance from NERC's various activities. The "Guideline and Technical Basis" section and text boxes with "Examples" and "Rationale" are not intended to establish new Requirements under NERC's Reliability Standards or to modify the Requirements in any existing NERC Reliability Standard. Implementation of the "Guideline and Technical Basis" section, the Background section and text boxes with "Examples" and "Rationale" is not a substitute for compliance with Requirements in NERC's Reliability Standards."

## **5. Background:**

This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

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<sup>3</sup> "Clear line of sight" means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.

- a) Performance-based — defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome?*
- b) Risk-based — preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?*
- c) Competency-based — defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?*

The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

For this standard, the requirements have been developed as follows:

Performance-based: Requirements 1 and 2

Competency-based: Requirement 3

Risk-based: Requirements 4, 5, 6 and 7

R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term “public lands” includes municipal lands, village lands, city lands, and a host of other governmental entities.

This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

## B. Requirements and Measures

- R1.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below<sup>4</sup> [*Violation Risk Factor: High*] [*Time Horizon: Real-time*]:
1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,<sup>5</sup>
  2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,<sup>6</sup>
  3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage<sup>7</sup>,
  4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.<sup>8</sup>
- M1.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)
- R2.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below<sup>9</sup> [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time*]:
1. An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage,<sup>10</sup>

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<sup>4</sup> This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's or applicable Generator Owner's right to exercise its full legal rights on the ROW.

<sup>5</sup> If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

<sup>6</sup> Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

<sup>7</sup> *Id.*

<sup>8</sup> *Id.*

<sup>9</sup> See footnote 4.

<sup>10</sup> See footnote 5.

2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,<sup>11</sup>
3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,<sup>12</sup>
4. An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage<sup>13</sup>

**M2.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)

**R3.** Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following:

**3.1** Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;

**3.2** Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

*[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

**M3.** The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

**R4.** Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment *[Violation Risk Factor: Medium] [Time Horizon: Real-time]*.

**M4.** Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence

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<sup>11</sup> See footnote 6.

<sup>12</sup> *Id.*

<sup>13</sup> *Id.*



may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

- R5.** When a applicable Transmission Owner and applicable Generator Owner is constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].
- M5.** Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)
- R6.** Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW<sup>14</sup> [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].
- M6.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)
- R7.** Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

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<sup>14</sup> When the applicable Transmission Owner or applicable Generator Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.

- Change in expected growth rate/ environmental factors
- Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner<sup>15</sup>
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Emerging technologies

**M7.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

## C. Compliance

### 1. Compliance Monitoring Process

#### 1.1 Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

For NERC, a third-party monitor without vested interest in the outcome for NERC shall serve as the Compliance Enforcement Authority.

#### 1.2 Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, Measures M1, M2, M3, M5, M6 and M7 for three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

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<sup>15</sup> Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.

The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

### **1.3 Compliance Monitoring and Enforcement Processes:**

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaint

Periodic Data Submittal

### **1.4 Additional Compliance Information**

***Periodic Data Submittal:*** The applicable Transmission Owner and applicable Generator Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of an

- IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
  - Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
  - Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
  - Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
  - Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.
  - Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

**Table of Compliance Elements**

R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Real-time	High			<p>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.</p>	<p>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following:</p> <ul style="list-style-type: none"> <li>• A fall-in from inside the active transmission line ROW</li> <li>• Blowing together of applicable lines and vegetation located inside the active transmission line ROW</li> <li>• A grow-in</li> </ul>
R2	Real-time	Medium			<p>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.</p>	<p>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following:</p> <ul style="list-style-type: none"> <li>• A fall-in from inside the active transmission line</li> </ul>

						<p>ROW</p> <ul style="list-style-type: none"> <li>Blowing together of applicable lines and vegetation located inside the active transmission line ROW</li> <li>A grow-in</li> </ul>
R3	Long-Term Planning	Lower		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity’s applicable lines. (Requirement R3, Part 3.2)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity’s applicable lines. Requirement R3, Part 3.1)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity’s applicable lines.
R4	Real-time	Medium			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5	Operations Planning	Medium				The responsible entity did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6	Operations	Medium	The responsible entity	The responsible entity failed	The responsible entity failed to	The responsible entity failed to

	Planning		failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7	Operations Planning	Medium	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

**D. Regional Differences**

None.

**E. Interpretations**

None.

**F. Associated Documents**

Guideline and Technical Basis (attached).

## Guideline and Technical Basis

### Effective dates:

The first two sentences of the Effective Dates section is standard language used in most NERC standards to cover the general effective date and is sufficient to cover the vast majority of situations. Five special cases are needed to cover effective dates for individual lines which undergo transitions after the general effective date. These special cases cover the effective dates for those lines which are initially becoming subject to the standard, those lines which are changing their applicability within the standard, and those lines which are changing in a manner that removes their applicability to the standard.

Case 1 is needed because the Planning Coordinators may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2011 may identify a line to have that designation beginning in PY 2021, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. The table below has some explanatory examples of the application.

<u>Date that Planning Study is completed</u>	<u>PY the line will become an IROL element</u>	<u>Date 1</u>	<u>Date 2</u>	<u>Effective Date The latter of Date 1 or Date 2</u>
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Case 2 is needed because a line operating below 200kV designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Case 3 is needed because a line operating at 200 kV or above that once was designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network. Such changes result in the need to apply R1 to that line until that date is reached and then to apply R2 to that line thereafter.

Case 4 is needed because an existing line that is to be operated at 200 kV or above can be acquired by an applicable Transmission Owner or applicable Generator Owner from a third party



such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network which will thereafter make the line subject to the standard.

Case 5 is needed because an existing line that is operated below 200 kV can be acquired by an applicable Transmission Owner or applicable Generator Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network. In this special case the line upon acquisition was designated as an element of an Interconnection Reliability Operating Limit (IROL) or an element of a Major WECC Transfer Path.

### **Defined Terms:**

#### **Explanation for revising the definition of ROW:**

The current NERC glossary definition of Right of Way has been modified to include Generator Owners and to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This modified definition represents a slight but significant departure from the strict legal definition of “right of way” in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the revised definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

The Project 2010-07 team further modified that proposed definition to include applicable Generator Owners.

#### **Explanation for revising the definition of Vegetation Inspections:**

The current glossary definition of this NERC term is being modified to include Generator Owners and to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

The Project 2010-07 team further modified that proposed definition to include applicable Generator Owners.

**Explanation of the definition of the MVCD:**

The MVCD is a calculated minimum distance that is derived from the Gallet Equations. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 below provides MVCD values for various voltages and altitudes. Details of the equations and an example calculation are provided in Appendix 1 of the Technical Reference Document.

**Requirements R1 and R2:**

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each applicable Transmission Owner or applicable Generator Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element of an IROL or Major WECC Transfer Path. R2 is applicable to all other lines that are not elements of IROLs, and not elements of Major WECC Transfer Paths.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations as described more fully in the Technical Reference document.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a

vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will prevent transmission outages.

If the applicable Transmission Owner or applicable Generator Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

### **Requirement R3:**

R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable Transmission Owner or applicable Generator Owner uses for vegetation management.

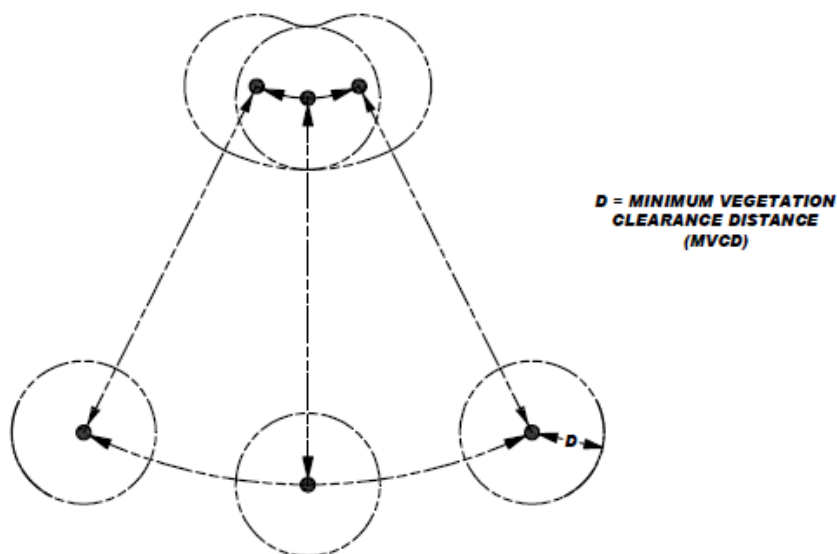
An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an

applicable Transmission Owner or applicable Generator Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below. In the Technical Reference document more figures and explanations of conductor dynamics are provided.



**Figure 1**

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

#### **Requirement R4:**

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include

communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner or applicable Generator Owner employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

**Requirement R5:**

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time

constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the applicable Transmission Owner or applicable Generator Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The applicable Transmission Owner or applicable Generator Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

**Requirement R6:**

R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner's ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission Owner or applicable Generator Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be  $100/2000 = 0.05$  or 5%. The "Low VSL" for R6 would apply in this example.

**Requirement R7:**

R7 is a risk-based requirement. The applicable Transmission Owner or applicable Generator Owner is required to complete its annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a “span-by-span”, or even a “line-by-line” detailed description of all work to be performed. It is only intended to require that the applicable Transmission Owner or applicable Generator Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

For example, when an applicable Transmission Owner or applicable Generator Owner identifies 1,000 miles of applicable transmission lines to be completed in the applicable Transmission Owner’s or applicable Generator Owner’s annual plan, the applicable Transmission Owner or applicable Generator Owner will be responsible completing those identified miles. If an applicable Transmission Owner or applicable Generator Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be:  $1000 - 100$  (deferred miles) = 900 modified annual plan, or  $900 / 900 = 100\%$  completed annual miles. If an applicable Transmission Owner or applicable Generator Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be:  $1000 - 875 = 125$  miles failed to complete then,  $125$  miles (not completed) /  $1000$  total annual plan miles =  $12.5\%$  failed to complete.

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner’s or applicable Generator Owner’s system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.

In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner’s or applicable Generator Owner’s easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.



FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)<sup>16</sup>  
 For **Alternating Current** Voltages (feet)

( AC ) Nominal System Voltage (KV)	( AC ) Maximum System Voltage (kV) <sup>17</sup>	MVCD (feet)  Over sea level up to 500 ft	MVCD (feet)  Over 500 ft up to 1000 ft	MVCD feet  Over 1000 ft up to 2000 ft	MVCD feet  Over 2000 ft up to 3000 ft	MVCD feet  Over 3000 ft up to 4000 ft	MVCD feet  Over 4000 ft up to 5000 ft	MVCD feet  Over 5000 ft up to 6000 ft	MVCD feet  Over 6000 ft up to 7000 ft	MVCD feet  Over 7000 ft up to 8000 ft	MVCD feet  Over 8000 ft up to 9000 ft	MVCD feet  Over 9000 ft up to 10000 ft	MVCD feet  Over 10000 ft up to 11000 ft
765	800	8.2ft	8.33ft	8.61ft	8.89ft	9.17ft	9.45ft	9.73ft	10.01ft	10.29ft	10.57ft	10.85ft	11.13ft
500	550	5.15ft	5.25ft	5.45ft	5.66ft	5.86ft	6.07ft	6.28ft	6.49ft	6.7ft	6.92ft	7.13ft	7.35ft
345	362	3.19ft	3.26ft	3.39ft	3.53ft	3.67ft	3.82ft	3.97ft	4.12ft	4.27ft	4.43ft	4.58ft	4.74ft
287	302	3.88ft	3.96ft	4.12ft	4.29ft	4.45ft	4.62ft	4.79ft	4.97ft	5.14ft	5.32ft	5.50ft	5.68ft
230	242	3.03ft	3.09ft	3.22ft	3.36ft	3.49ft	3.63ft	3.78ft	3.92ft	4.07ft	4.22ft	4.37ft	4.53ft
161*	169	2.05ft	2.09ft	2.19ft	2.28ft	2.38ft	2.48ft	2.58ft	2.69ft	2.8ft	2.91ft	3.03ft	3.14ft
138*	145	1.74ft	1.78ft	1.86ft	1.94ft	2.03ft	2.12ft	2.21ft	2.3ft	2.4ft	2.49ft	2.59ft	2.7ft
115*	121	1.44ft	1.47ft	1.54ft	1.61ft	1.68ft	1.75ft	1.83ft	1.91ft	1.99ft	2.07ft	2.16ft	2.25ft
88*	100	1.18ft	1.21ft	1.26ft	1.32ft	1.38ft	1.44ft	1.5ft	1.57ft	1.64ft	1.71ft	1.78ft	1.86ft
69*	72	0.84ft	0.86ft	0.90ft	0.94ft	0.99ft	1.03ft	1.08ft	1.13ft	1.18ft	1.23ft	1.28ft	1.34ft

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

<sup>16</sup> The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

<sup>17</sup> Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

**TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)<sup>7</sup>  
For Alternating Current Voltages (meters)**

( AC ) Nominal System Voltage (KV)	( AC ) Maximum System Voltage <sup>8</sup> (kV)	MVCD meters  Over sea level up to 152.4 m	MVCD meters  Over 152.4 m up to 304.8 m	MVCD meters  Over 304.8 m up to 609.6m	MVCD meters  Over 609.6m up to 914.4m	MVCD meters  Over 914.4m up to 1219.2m	MVCD meters  Over 1219.2m up to 1524m	MVCD meters  Over 1524 m up to 1828.8 m	MVCD meters  Over 1828.8m up to 2133.6m	MVCD meters  Over 2133.6m up to 2438.4m	MVCD meters  Over 2438.4m up to 2743.2m	MVCD meters  Over 2743.2m up to 3048m	MVCD meters  Over 3048m up to 3352.8m
765	800	2.49m	2.54m	2.62m	2.71m	2.80m	2.88m	2.97m	3.05m	3.14m	3.22m	3.31m	3.39m
500	550	1.57m	1.6m	1.66m	1.73m	1.79m	1.85m	1.91m	1.98m	2.04m	2.11m	2.17m	2.24m
345	362	0.97m	0.99m	1.03m	1.08m	1.12m	1.16m	1.21m	1.26m	1.30m	1.35m	1.40m	1.44m
287	302	1.18m	0.88m	1.26m	1.31m	1.36m	1.41m	1.46m	1.51m	1.57m	1.62m	1.68m	1.73m
230	242	0.92m	0.94m	0.98m	1.02m	1.06m	1.11m	1.15m	1.19m	1.24m	1.29m	1.33m	1.38m
161*	169	0.62m	0.64m	0.67m	0.69m	0.73m	0.76m	0.79m	0.82m	0.85m	0.89m	0.92m	0.96m
138*	145	0.53m	0.54m	0.57m	0.59m	0.62m	0.65m	0.67m	0.70m	0.73m	0.76m	0.79m	0.82m
115*	121	0.44m	0.45m	0.47m	0.49m	0.51m	0.53m	0.56m	0.58m	0.61m	0.63m	0.66m	0.69m
88*	100	0.36m	0.37m	0.38m	0.40m	0.42m	0.44m	0.46m	0.48m	0.50m	0.52m	0.54m	0.57m
69*	72	0.26m	0.26m	0.27m	0.29m	0.30m	0.31m	0.33m	0.34m	0.36m	0.37m	0.39m	0.41m

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

**TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)<sup>7</sup>**  
**For Direct Current Voltages feet (meters)**

( DC ) Nominal Pole to Ground Voltage (kV)	MVCD meters	MVCD meters	MVCD meters	MVCD meters	MVCD meters	MVCD meters	MVCD meters	MVCD meters	MVCD meters	MVCD meters	MVCD meters	MVCD meters
Over sea level up to 500 ft  (Over sea level up to 152.4 m)	Over 500 ft up to 1000 ft  (Over 152.4 m up to 304.8 m)	Over 1000 ft up to 2000 ft  (Over 304.8 m up to 609.6m)	Over 2000 ft up to 3000 ft  (Over 609.6m up to 914.4m)	Over 3000 ft up to 4000 ft  (Over 914.4m up to 1219.2m)	Over 4000 ft up to 5000 ft  (Over 1219.2m up to 1524m)	Over 5000 ft up to 6000 ft  (Over 1524 m up to 1828.8 m)	Over 6000 ft up to 7000 ft  (Over 1828.8m up to 2133.6m)	Over 7000 ft up to 8000 ft  (Over 2133.6m up to 2438.4m)	Over 8000 ft up to 9000 ft  (Over 2438.4m up to 2743.2m)	Over 9000 ft up to 10000 ft  (Over 2743.2m up to 3048m)	Over 10000 ft up to 11000 ft  (Over 3048m up to 3352.8m)	
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

**Notes:**

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet Equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 uses the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-01 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines, as such, are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-

service ac line is approximately 2.0 per unit. This value is a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below is considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit is considered a realistic maximum.

The Gallet Equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet Equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

While EPRI is currently trying to establish empirical data for spark-over distances to live vegetation, there are no spark-over formulas currently derived expressly for vegetation to conductor minimum distances. Therefore the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

**Comparison of spark-over distances computed using Gallet wet equations vs. IEEE 516-2003 MAID distances**

( AC ) Nom System Voltage (kV)	( AC ) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 feet	Table 7 (Table D.5 for feet) IEEE 516-2003 MAID (ft) @ Alt. 3000 feet
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

**Rationale:**

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

**Rationale for Applicability (section 4.2.4):**

The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

**Rationale for Applicability (section 4.3):**

Within the text of NERC Reliability Standard FAC-003-3, “transmission line(s) and “applicable line(s) can also refer to the generation Facilities as referenced in 4.3 and its subsections.

**Rationale for R1 and R2:**

Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable Transmission Owner's or applicable Generator Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.
2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

**Rationale for R3:**

The documentation provides a basis for evaluating the competency of the applicable Transmission Owner's or applicable Generator Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions. See Figure

**Rationale for R4:**

This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

**Rationale for R5:**

Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

**Rationale for R6:**

Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable.

Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

**Rationale for R7:**

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

**Version History**

<b>Version</b>	<b>Date</b>	<b>Action</b>	<b>Change Tracking</b>
3	September 29, 2011	Using the latest draft of FAC-003-2 from the Project 2007-07 SDT, modified proposed definitions and Applicability to include Generator Owners of a certain length.	Revision under Project 2010-07
3	May 9, 2012	Adopted by Board of Trustees	



Effective Dates

~~This~~ There are two effective dates associated with this standard.

The first effective date allows Generator Owners time to develop documented maintenance strategies or procedures or processes or specifications as outlined in Requirement R3.

In those jurisdictions where regulatory approval is required, Requirement R3 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. ~~Where~~ In those jurisdictions where no regulatory approval is required, ~~the standard~~ Requirement R3 becomes effective on the first ~~calendar~~ day of the first calendar quarter one year ~~after~~ following Board of ~~Trustees~~ Trustees’ adoption ~~– or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

Requirement	Jurisdiction									
	Alberta	British Columbia	Manitoba	New Brunswick	Newfoundland	Nova Scotia	Ontario	Quebec	Saskatchewan	USA
<del>R1 – R7</del> (All Req.)	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD

The second effective date allows entities time to comply with Requirements R1, R2, R4, R5, R6, and R7.

In those jurisdictions where regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 become effective on the first day of the first calendar quarter two years following Board of Trustees’ adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.
2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.
3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.
4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.
5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

## A. Introduction

1. **Title:** Transmission Vegetation Management
2. **Number:** FAC-003-~~23~~
3. **Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

### 4. Applicability

#### 4.1. Functional Entities:

~~4.1.1.~~ ~~4.1.1~~ Applicable Transmission Owners

4.1.1.1 Transmission Owners that own Transmission Facilities defined in 4.2.

~~4.1.2~~ Applicable Generator Owners

4.1.2.1 Generator Owners that own generation Facilities defined in 4.3

- 4.2. **Transmission Facilities:** Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal<sup>1</sup>, state, provincial, public, private, or tribal entities:

~~4.2.1.~~ Each overhead transmission line operated at 200kV or higher.

~~4.2.2.~~ Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.

~~4.2.3.~~ Each overhead transmission line operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

~~4.2.4.~~ Each overhead transmission line identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

- 4.3. **Generation Facilities:** Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal<sup>2</sup>, state, provincial, public, private, or tribal entities:

4.3.1 Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of

<sup>1</sup> EPAAct 2005 section 1211c: “Access approvals by Federal agencies.”

<sup>2</sup> Id.

interconnection with a Transmission Owner’s Facility or (2) do not have a clear line of sight<sup>3</sup> from the generating station switchyard fence to the point of interconnection with a Transmission Owner’s Facility and are:

4.3.1.1 Operated at 200kV or higher; or

4.3.1.2 Operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator; or

4.3.1.3 Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

Enforcement:

The Requirements within a Reliability Standard govern and will be enforced. The Requirements within a Reliability Standard define what an entity must do to be compliant and binds an entity to certain obligations of performance under Section 215 of the Federal Power Act. Compliance will in all cases be measured by determining whether a party met or failed to meet the Reliability Standard Requirement given the specific facts and circumstances of its use, ownership or operation of the bulk power system.

Measures provide guidance on assessing non-compliance with the Requirements. Measures are the evidence that could be presented to demonstrate compliance with a Reliability Standard Requirement and are not intended to contain the quantitative metrics for determining satisfactory performance nor to limit how an entity may demonstrate compliance if valid alternatives to demonstrating compliance are available in a specific case. A Reliability Standard may be enforced in the absence of specified Measures.

Entities must comply with the “Compliance” section in its entirety, including the Administrative Procedure that sets forth, among other things, reporting requirements.

The “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” are provided for informational purposes. They are designed to convey guidance from NERC’s various activities. The “Guideline and Technical Basis” section and text boxes with “Examples” and “Rationale” are not intended to establish new Requirements under NERC’s Reliability Standards or to modify the Requirements in any existing NERC Reliability Standard. Implementation of the “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” is not a substitute for compliance with Requirements in NERC’s Reliability Standards.”

## **5. Background:**

This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

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<sup>3</sup> “Clear line of sight” means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.

- a) Performance-based — defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome?*
- b) Risk-based — preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?*
- c) Competency-based — defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?*

The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

For this standard, the requirements have been developed as follows:

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3

- Risk-based: Requirements 4, 5, 6 and 7

R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term “public lands” includes municipal lands, village lands, city lands, and a host of other governmental entities.

This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

## B. Requirements and Measures

- R1.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below<sup>4</sup> [*Violation Risk Factor: High*] [*Time Horizon: Real-time*]:
1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,<sup>5</sup>
  2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,<sup>6</sup>
  3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,<sup>7</sup>
  4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.<sup>8</sup>
- M1.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)
- R2.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown ~~below~~<sup>2</sup>below<sup>9</sup> [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time*]:

<sup>4</sup> This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's or applicable Generator Owner's right to exercise its full legal rights on the ROW.

<sup>5</sup> If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

<sup>6</sup> Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

<sup>7</sup> Id.

<sup>8</sup> Id.

<sup>9</sup> See footnote 4.



1. An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage,<sup>310</sup>
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,<sup>411</sup>
3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,<sup>412</sup>
4. An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained ~~Outage~~<sup>4</sup>Outage<sup>13</sup>

**M2.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)

**R3.** Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following:

- 3.1** Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;
- 3.2** Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

*[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning];*

**M3.** The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

**R4.** Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment *[Violation Risk Factor: Medium] [Time Horizon: Real-time]*.

<sup>10</sup> See footnote 5.

<sup>11</sup> See footnote 6.

<sup>12</sup> Id.

<sup>13</sup> Id.



- M4.** Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)
- R5.** When a applicable Transmission Owner and applicable Generator Owner is constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].
- M5.** Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)
- R6.** Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW<sup>14</sup> [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].
- M6.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)
- R7.** Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured

<sup>14</sup> When the applicable Transmission Owner or applicable Generator Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.

in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

- Change in expected growth rate/ environmental factors
- Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner<sup>15</sup>
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Emerging technologies

**M7.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

## C. Compliance

### 1. Compliance Monitoring Process

#### 1.1 Compliance Enforcement Authority

~~Regional Entity~~ The Regional Entity shall serve as the Compliance Enforcement Authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

For NERC, a third-party monitor without vested interest in the outcome for NERC shall serve as the Compliance Enforcement Authority.

#### 1.2 Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

<sup>15</sup> Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.

The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, Measures M1, M2, M3, M5, M6 and M7 for three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

### 1.3 Compliance Monitoring and Enforcement Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint
- Periodic Data Submittal

### 1.4 Additional Compliance Information

**Periodic Data Submittal:** The applicable Transmission Owner and applicable Generator Owner will submit a quarterly report to its Regional Entity, or the Regional Entity’s designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following:

- o The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Real-time	High	N/A	N/A	The <b>Transmission Owner</b> responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.	The <b>Transmission Owner</b> responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following: <ul style="list-style-type: none"> <li>• A fall-in from inside the active transmission line ROW</li> <li>• Blowing together of applicable lines and vegetation located inside the active transmission line ROW</li> <li>• A grow-in</li> </ul>
R2	Real-time	Medium	N/A	N/A	The <b>Transmission Owner</b> responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time	The <b>Transmission Owner</b> responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of

					absent a Sustained Outage.	the following: <ul style="list-style-type: none"> <li>• A fall-in from inside the active transmission line ROW</li> <li>• Blowing together of applicable lines and vegetation located inside the active transmission line ROW</li> <li>• A grow-in</li> </ul>
R3	Long-Term Planning	Lower	N/A	The <del>Transmission Owner</del> responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the <del>Transmission Owner's</del> responsible entity's applicable lines. (Requirement R3, Part 3.2)	The <del>Transmission Owner</del> responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the <del>Transmission Owner's</del> responsible entity's applicable lines. Requirement R3, Part 3.1)	The <del>Transmission Owner</del> responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the <del>Transmission Owner's</del> responsible entity's applicable lines.
R4	Real-time	Medium	N/A	N/A	The <del>Transmission Owner</del> responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The <del>Transmission Owner</del> responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.

R5	Operations Planning	Medium	N/A	N/A	N/A	The <del>Transmission Owner</del> responsible entity did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6	Operations Planning	Medium	The <del>Transmission Owner</del> responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The <del>Transmission Owner</del> responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The <del>Transmission Owner</del> responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The <del>Transmission Owner</del> responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7	Operations Planning	Medium	The <del>Transmission Owner</del> responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The <del>Transmission Owner</del> responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The <del>Transmission Owner</del> responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The <del>Transmission Owner</del> responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Differences

None.

E. Interpretations

None.

F. Associated Documents

Guideline and Technical Basis (attached).





## Guideline and Technical Basis

### **Enforcement:**

~~The Requirements within a Reliability Standard govern and will be enforced. The Requirements within a Reliability Standard define what an entity must do to be compliant and binds an entity to certain obligations of performance under Section 215 of the Federal Power Act. Compliance will in all cases be measured by determining whether a party met or failed to meet the Reliability Standard Requirement given the specific facts and circumstances of its use, ownership or operation of the bulk power system.~~

~~Measures provide guidance on assessing non-compliance with the Requirements. Measures are the evidence that could be presented to demonstrate compliance with a Reliability Standard Requirement and are not intended to contain the quantitative metrics for determining satisfactory performance nor to limit how an entity may demonstrate compliance if valid alternatives to demonstrating compliance are available in a specific case. A Reliability Standard may be enforced in the absence of specified Measures.~~

~~Entities must comply with the “Compliance” section in its entirety, including the Administrative Procedure that sets forth, among other things, reporting requirements.~~

~~The “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” are provided for informational purposes. They are designed to convey guidance from NERC’s various activities. The “Guideline and Technical Basis” section and text boxes with “Examples” and “Rationale” are not intended to establish new Requirements under NERC’s Reliability Standards or to modify the Requirements in any existing NERC Reliability Standard. Implementation of the “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” is not a substitute for compliance with Requirements in NERC’s Reliability Standards.”~~

### **Effective dates:**

The first two sentences of the Effective Dates section is standard language used in most NERC standards to cover the general effective date and is sufficient to cover the vast majority of situations. Five special cases are needed to cover effective dates for individual lines which undergo transitions after the general effective date. These special cases cover the effective dates for those lines which are initially becoming subject to the standard, those lines which are changing their applicability within the standard, and those lines which are changing in a manner that removes their applicability to the standard.

Case 1 is needed because the Planning Coordinators may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2011 may identify a line to have that designation beginning in PY 2021, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become

subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. The table below has some explanatory examples of the application.

<u>Date that Planning Study is completed</u>	<u>PY the line will become an IROL element</u>	<u>Date 1</u>	<u>Date 2</u>	<u>Effective Date The latter of Date 1 or Date 2</u>
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Case 2 is needed because a line operating below 200kV designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Case 3 is needed because a line operating at 200 kV or above that once was designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network. Such changes result in the need to apply R1 to that line until that date is reached and then to apply R2 to that line thereafter.

Case 4 is needed because an existing line that is to be operated at 200 kV or above can be acquired by an applicable Transmission Owner or applicable Generator Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network which will thereafter make the line subject to the standard.

Case 5 is needed because an existing line that is operated below 200 kV can be acquired by an applicable Transmission Owner or applicable Generator Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission owner/Owner or applicable Generator Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network. In this special case the line upon acquisition was designated as an element of an Interconnection Reliability Operating Limit (IROL) or an element of a Major WECC Transfer Path.

**Defined Terms:**

**Explanation for revising the definition of ROW:**

The current NERC glossary definition of Right of Way has been modified to include Generator Owners and to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This modified definition represents a slight but significant departure from the strict legal definition of “right of way” in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the revised definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

The Project 2010-07 team further modified that proposed definition to include applicable Generator Owners.

#### **Explanation for revising the definition of Vegetation Inspections:**

The current glossary definition of this NERC term is being modified to include Generator Owners and to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

The Project 2010-07 team further modified that proposed definition to include applicable Generator Owners.

#### **Explanation of the definition of the MVCD:**

The MVCD is a calculated minimum distance that is derived from the Gallet Equations. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 below provides MVCD values for various voltages and altitudes. Details of the equations and an example calculation are provided in Appendix 1 of the Technical Reference Document.

#### **Guidelines:**

#### **Requirements R1 and R2:**

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements;

however, they apply to different Facilities. Both R1 and R2 require each applicable Transmission Owner or applicable Generator Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element of an IROL or Major WECC Transfer Path. R2 is applicable to all other lines that are not elements of IROLs, and not elements of Major WECC Transfer Paths.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations as described more fully in the Technical Reference document.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission ~~Operator~~Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will prevent transmission outages.

If the applicable Transmission Owner or applicable Generator Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the ~~TO~~applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

### **Requirement R3:**

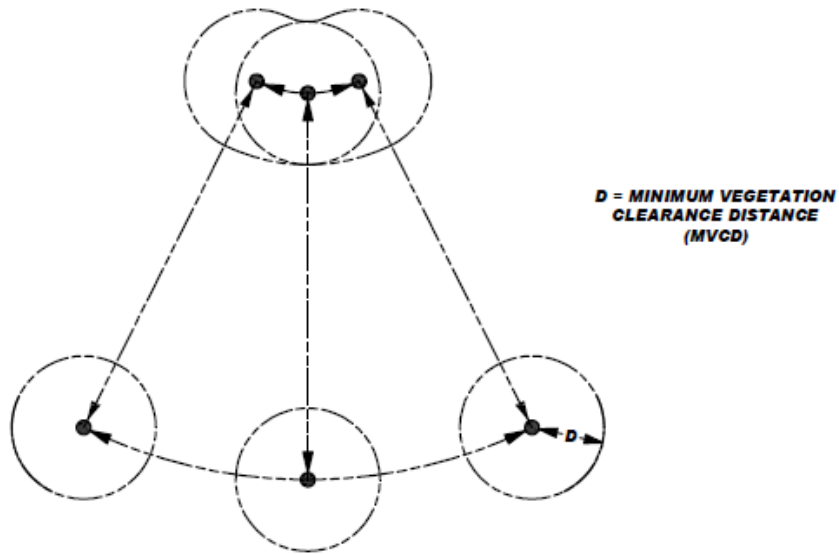
R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, ~~an applicable~~ Transmission Owner or applicable Generator Owner uses for vegetation management.

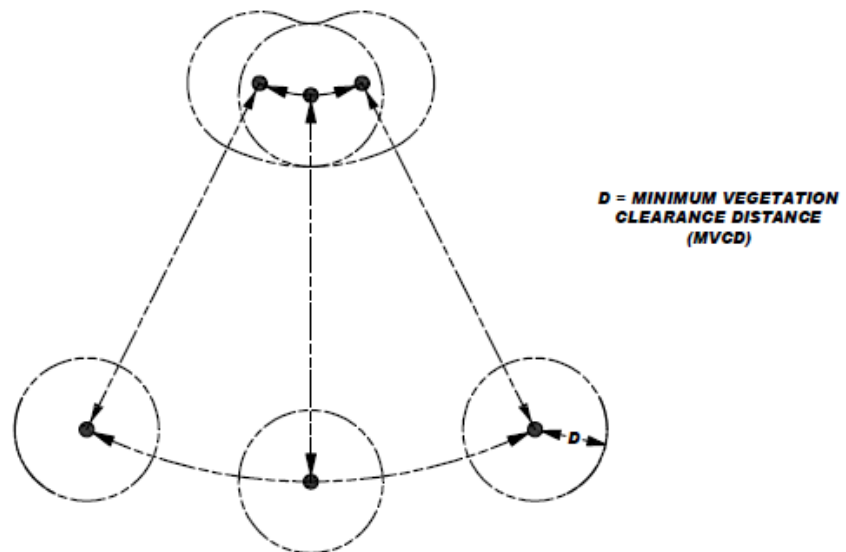
An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach ~~an~~ applicable Transmission Owner or applicable Generator Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below. In the Technical Reference document more figures and explanations of conductor dynamics are provided.





**Figure 1**

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

**Requirement R4:**

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled),



crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner or applicable Generator Owner employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

#### **Requirement R5:**

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.



However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the applicable Transmission Owner or applicable Generator Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The applicable Transmission Owner or applicable Generator Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

#### **Requirement R6:**

R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner's ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission Owner or applicable Generator Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when ~~a~~ an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be  $100/2000 = 0.05$  or 5%. The "Low VSL" for R6 would apply in this example.

**Requirement R7:**

R7 is a risk-based requirement. The applicable Transmission Owner or applicable Generator Owner is required to complete its an annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a “span-by-span”, or even a “line-by-line” detailed description of all work to be performed. It is only intended to require that the applicable Transmission Owner or applicable Generator Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

For example, when ~~a~~ an applicable Transmission Owner or applicable Generator Owner identifies 1,000 miles of applicable transmission lines to be completed in the applicable Transmission Owner’s or applicable Generator Owner’s annual plan, the applicable Transmission Owner or applicable Generator Owner will be responsible completing those identified miles. If a applicable Transmission Owner or applicable Generator Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be:  $1000 - 100$  (deferred miles) = 900 modified annual plan, or  $900 / 900 = 100\%$  completed annual miles. If ~~a~~ an applicable Transmission Owner or applicable Generator Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be:  $1000 - 875 = 125$  miles failed to complete then,  $125$  miles (not completed) /  $1000$  total annual plan miles =  $12.5\%$  failed to complete.

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner’s or applicable Generator Owner’s system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.

In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner’s or applicable Generator Owner’s easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)<sup>16</sup>  
 For **Alternating Current** Voltages (feet)

( AC ) Nominal System Voltage (KV)	( AC ) Maximum System Voltage (kV) <sup>17</sup>	MVCD (feet)  Over sea level up to 500 ft	MVCD (feet)  Over 500 ft up to 1000 ft	MVCD feet  Over 1000 ft up to 2000 ft	MVCD feet  Over 2000 ft up to 3000 ft	MVCD feet  Over 3000 ft up to 4000 ft	MVCD feet  Over 4000 ft up to 5000 ft	MVCD feet  Over 5000 ft up to 6000 ft	MVCD feet  Over 6000 ft up to 7000 ft	MVCD feet  Over 7000 ft up to 8000 ft	MVCD feet  Over 8000 ft up to 9000 ft	MVCD feet  Over 9000 ft up to 10000 ft	MVCD feet  Over 10000 ft up to 11000 ft
765	800	8.2ft	8.33ft	8.61ft	8.89ft	9.17ft	9.45ft	9.73ft	10.01ft	10.29ft	10.57ft	10.85ft	11.13ft
500	550	5.15ft	5.25ft	5.45ft	5.66ft	5.86ft	6.07ft	6.28ft	6.49ft	6.7ft	6.92ft	7.13ft	7.35ft
345	362	3.19ft	3.26ft	3.39ft	3.53ft	3.67ft	3.82ft	3.97ft	4.12ft	4.27ft	4.43ft	4.58ft	4.74ft
287	302	3.88ft	3.96ft	4.12ft	4.29ft	4.45ft	4.62ft	4.79ft	4.97ft	5.14ft	5.32ft	5.50ft	5.68ft
230	242	3.03ft	3.09ft	3.22ft	3.36ft	3.49ft	3.63ft	3.78ft	3.92ft	4.07ft	4.22ft	4.37ft	4.53ft
161*	169	2.05ft	2.09ft	2.19ft	2.28ft	2.38ft	2.48ft	2.58ft	2.69ft	2.8ft	2.91ft	3.03ft	3.14ft
138*	145	1.74ft	1.78ft	1.86ft	1.94ft	2.03ft	2.12ft	2.21ft	2.3ft	2.4ft	2.49ft	2.59ft	2.7ft
115*	121	1.44ft	1.47ft	1.54ft	1.61ft	1.68ft	1.75ft	1.83ft	1.91ft	1.99ft	2.07ft	2.16ft	2.25ft
88*	100	1.18ft	1.21ft	1.26ft	1.32ft	1.38ft	1.44ft	1.5ft	1.57ft	1.64ft	1.71ft	1.78ft	1.86ft
69*	72	0.84ft	0.86ft	0.90ft	0.94ft	0.99ft	1.03ft	1.08ft	1.13ft	1.18ft	1.23ft	1.28ft	1.34ft

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

<sup>16</sup> The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

<sup>17</sup> Where applicable lines are operated at nominal voltages other than those listed, ~~the applicable~~ Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

**TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)<sup>7</sup>**  
**For Alternating Current Voltages (meters)**

( AC ) Nominal System Voltage (KV)	( AC ) Maximum System Voltage (kV) <sup>8</sup>	MVCD meters  Over sea level up to 152.4 m	MVCD meters  Over 152.4 m up to 304.8 m	MVCD meters  Over 304.8 m up to 609.6m	MVCD meters  Over 609.6m up to 914.4m	MVCD meters  Over 914.4m up to 1219.2m	MVCD meters  Over 1219.2m up to 1524m	MVCD meters  Over 1524 m up to 1828.8 m	MVCD meters  Over 1828.8m up to 2133.6m	MVCD meters  Over 2133.6m up to 2438.4m	MVCD meters  Over 2438.4m up to 2743.2m	MVCD meters  Over 2743.2m up to 3048m	MVCD meters  Over 3048m up to 3352.8m
765	800	2.49m	2.54m	2.62m	2.71m	2.80m	2.88m	2.97m	3.05m	3.14m	3.22m	3.31m	3.39m
500	550	1.57m	1.6m	1.66m	1.73m	1.79m	1.85m	1.91m	1.98m	2.04m	2.11m	2.17m	2.24m
345	362	0.97m	0.99m	1.03m	1.08m	1.12m	1.16m	1.21m	1.26m	1.30m	1.35m	1.40m	1.44m
287	302	1.18m	0.88m	1.26m	1.31m	1.36m	1.41m	1.46m	1.51m	1.57m	1.62m	1.68m	1.73m
230	242	0.92m	0.94m	0.98m	1.02m	1.06m	1.11m	1.15m	1.19m	1.24m	1.29m	1.33m	1.38m
161*	169	0.62m	0.64m	0.67m	0.69m	0.73m	0.76m	0.79m	0.82m	0.85m	0.89m	0.92m	0.96m
138*	145	0.53m	0.54m	0.57m	0.59m	0.62m	0.65m	0.67m	0.70m	0.73m	0.76m	0.79m	0.82m
115*	121	0.44m	0.45m	0.47m	0.49m	0.51m	0.53m	0.56m	0.58m	0.61m	0.63m	0.66m	0.69m
88*	100	0.36m	0.37m	0.38m	0.40m	0.42m	0.44m	0.46m	0.48m	0.50m	0.52m	0.54m	0.57m
69*	72	0.26m	0.26m	0.27m	0.29m	0.30m	0.31m	0.33m	0.34m	0.36m	0.37m	0.39m	0.41m

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)<sup>7</sup>  
 For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole-to Ground Voltage (kV)MVCD meters	(DC) Nominal Pole-to Ground Voltage (kV)MVCD meters	(DC) Nominal Pole-to Ground Voltage (kV)MVCD meters	(DC) Nominal Pole-to Ground Voltage (kV)MVCD meters	(DC) Nominal Pole-to Ground Voltage (kV)MVCD meters	(DC) Nominal Pole-to Ground Voltage (kV)MVCD meters	(DC) Nominal Pole-to Ground Voltage (kV)MVCD meters	(DC) Nominal Pole-to Ground Voltage (kV)MVCD meters	(DC) Nominal Pole-to Ground Voltage (kV)MVCD meters	(DC) Nominal Pole-to Ground Voltage (kV)MVCD meters	(DC) Nominal Pole-to Ground Voltage (kV)MVCD meters	(DC) Nominal Pole-to Ground Voltage (kV)MVCD meters
	Over sea level up to 500 ft  (Over sea level up to 152.4 m)	Over 500 ft up to 1000 ft  (Over 152.4 m up to 304.8 m)	Over 1000 ft up to 2000 ft  (Over 304.8 m up to 609.6m)	Over 2000 ft up to 3000 ft  (Over 609.6m up to 914.4m)	Over 3000 ft up to 4000 ft  (Over 914.4m up to 1219.2m)	Over 4000 ft up to 5000 ft  (Over 1219.2m up to 1524m)	Over 5000 ft up to 6000 ft  (Over 1524 m up to 1828.8 m)	Over 6000 ft up to 7000 ft  (Over 1828.8m up to 2133.6m)	Over 7000 ft up to 8000 ft  (Over 2133.6m up to 2438.4m)	Over 8000 ft up to 9000 ft  (Over 2438.4m up to 2743.2m)	Over 9000 ft up to 10000 ft  (Over 2743.2m up to 3048m)	Over 10000 ft up to 11000 ft  (Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

### Notes:

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet Equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 uses the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-01 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines, as such, are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-

service ac line is approximately 2.0 per unit. This value is a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below is considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit is considered a realistic maximum.

The Gallet Equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet Equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

While EPRI is currently trying to establish empirical data for spark-over distances to live vegetation, there are no spark-over formulas currently derived expressly for vegetation to conductor minimum distances. Therefore the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.



**Comparison of spark-over distances computed using Gallet wet equations vs. IEEE 516-2003 MAID distances**

( AC ) Nom System Voltage (kV)	( AC ) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 feet	Table 7 (Table D.5 for feet) IEEE 516-2003 MAID (ft) @ Alt. 3000 feet
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

**Rationale:**

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

**Rationale for Applicability (section 4.2.4):**

The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. ~~3) NERC has a project in place to address at a later date the applicability of this standard to Generation Owners.~~ 4) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

**Rationale for Applicability (section 4.3):**

Within the text of NERC Reliability Standard FAC-003-3, “transmission line(s) and “applicable line(s) can also refer to the generation Facilities as referenced in 4.3 and its subsections.

**Rationale for R1 and R2:**

Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of ~~an applicable~~ Transmission Owner's or applicable Generator Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.
2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

**Rationale for R3:**

The documentation provides a basis for evaluating the competency of the applicable Transmission Owner's or applicable Generator Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions. See Figure ~~1 for an illustration of possible conductor locations.~~

**Rationale for R4:**

This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

**Rationale for R5:**

Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

**Rationale for R6:**

Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

**Rationale for R7:**

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

**Version History**

<b>Version</b>	<b>Date</b>	<b>Action</b>	<b>Change Tracking</b>
<del>13</del>	<del>TBA</del> <u>September 29, 2011</u>	<del>1. Added "Standard Development Roadmap."</del> <del>2. Changed "60" to "Sixty" in section A, 5.2.</del> <del>3. Added "Proposed Effective Date: April 7, 2006" to footer.</del> <del>4. Added "Draft 3: November 17, 2005" to footer. Using the latest draft of FAC-003-2 from the Project 2007-07 SDT, modified proposed definitions and Applicability to include Generator Owners of a certain length.</del>	<u>01/20/06</u> <u>Revision under Project 2010-07</u>
<del>1</del>	<del>April 4, 2007</del>	<del>Regulatory Approval—Effective Date</del>	<del>New</del>
<del>23</del>	<del>November 3, 2011</del> <u>May 9, 2012</u>	Adopted by <del>the NERC</del> Board of Trustees	

## Standard PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

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### A. Introduction

1. **Title:** Analysis and Mitigation of Transmission and Generation Protection System Misoperations
2. **Number:** PRC-004-2.1a
3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.
4. **Applicability**
  - 4.1. Transmission Owner.
  - 4.2. Distribution Provider that owns a transmission Protection System.
  - 4.3. Generator Owner.
5. **(Proposed) Effective Date:** In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements become effective upon Board of Trustees' adoption.

### B. Requirements

- R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- R2. The Generator Owner shall analyze its generator and generator interconnection Facility Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.

### C. Measures

- M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Entity's procedures.

### D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Enforcement Authority**

Regional Entity.

## Standard PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

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### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

### 1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

### 1.4. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation or generator interconnection Facility Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

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

### 1.5. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

## 2. Violation Severity Levels (no changes)

### E. Regional Differences

None identified.

### Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
2		Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised
2	August 5, 2010	Adopted by NERC Board of Trustees	

**Standard PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations**

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1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by the Board of Trustees	
1a	September 26, 2011	FERC Order issued approving the interpretation of R1 and R3 (FERC's Order is effective as of September 26, 2011)	
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	
2.1a		Errata change: Edited R2 to add "...and generator interconnection Facility..."	Revision under Project 2010-07
2.1a	February 9, 2012	Errata change adopted by the Board of Trustees	

**Appendix 1<sup>1</sup>**

<b>Requirement Number and Text of Requirement</b>
<p><b>R1.</b> The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization’s procedures developed for Reliability Standard PRC-003 Requirement 1.</p> <p><b>R3.</b> The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization’s procedures developed for PRC-003 R1.</p>
<p><b>Question:</b></p>
<p>Is protection for a radially-connected transformer protection system energized from the BES considered a transmission Protection System subject to this standard?</p>
<p><b>Response:</b></p>
<p>The request for interpretation of PRC-004-1 Requirements R1 and R3 focuses on the applicability of the term “transmission Protection System.” The NERC Glossary of Terms Used in Reliability Standards contains a definition of “Protection System” but does not contain a definition of transmission Protection System. In these two standards, use of the phrase transmission Protection System indicates that the requirements using this phrase are applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directly from the BES.</p> <p>A Protection System for a radially connected transformer energized from the BES would be considered a transmission Protection System and subject to these standards only if the protection trips an interrupting device that interrupts current supplied directly from the BES and the transformer is a BES element.</p>

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<sup>1</sup> When the request for interpretation was made, it was for a previous version of the standard. Although the interpretation references a previous version of the standard, because it is still applicable in this case, it is appended to this version of the standard.



## Standard PRC-004-~~2a~~2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

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### A. Introduction

1. **Title:** Analysis and Mitigation of Transmission and Generation Protection System Misoperations
2. **Number:** PRC-004-~~2a~~2.1a
3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.
4. **Applicability**
  - 4.1. Transmission Owner.
  - 4.2. Distribution Provider that owns a transmission Protection System.
  - 4.3. Generator Owner.
5. **(Proposed) Effective Date:** ~~The first day of the first calendar quarter, one year after applicable~~ In those jurisdictions where regulatory approval; or in is required, all requirements become effective upon approval. ~~In those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year after~~ all requirements become effective upon Board of Trustees' adoption. \_\_

### B. Requirements

- R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- R2. The Generator Owner shall analyze its generator and generator interconnection Facility Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.

### C. Measures

- M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Entity's procedures.

### D. Compliance

1. **Compliance Monitoring Process**

**Standard PRC-004-2a2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations**

**1.1. Compliance Enforcement Authority**

Regional Entity.

**1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

**1.3. Compliance Monitoring and Enforcement Processes:**

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.4. Data Retention**

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation or generator interconnection Facility Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

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

**1.5. Additional Compliance Information**

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

**2. Violation Severity Levels (no changes)**

**E. Regional Differences**

None identified.

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. Changed “Timeframe” to “Time Frame” in item D, 1.2.	<u>01/20/06</u>
<u>2</u>		<u>Modified to address Order No. 693 Directives</u>	<u>Revised</u>

**Standard PRC-004-~~2a~~2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations**

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		<u>contained in paragraph 1469.</u>	
2	August 5, 2010	Adopted by <del>the</del> NERC Board of Trustees	
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by the <del>NERC</del> Board of Trustees	
1a	September 26, 2011	FERC Order issued approving the interpretation of R1 and R3 (FERC's Order is effective as of September 26, 2011)	
<u>2a</u>	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	
<u>2.1a</u>		<u>Errata change: Edited R2 to add "...and generator interconnection Facility..."</u>	<u>Revision under Project 2010-07</u>
<u>2.1a</u>	<u>February 9, 2012</u>	<u>Errata change adopted by the Board of Trustees</u>	

### Appendix 1<sup>1</sup>

Requirement Number and Text of Requirement
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<p><b>-R1.</b> The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization’s procedures developed for Reliability Standard PRC-003 Requirement 1.</p>
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<p><b>R3.</b> The Transmission Owner, any Distribution Provider that owns a transmission Protection System,</p>
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<sup>1</sup> When the request for interpretation was made, it was for a previous version of the standard. Although the interpretation references a previous version of the standard, because it is still applicable in this case, it is appended to this version of the standard.

**Standard PRC-004-2a2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations**

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and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization’s procedures developed for PRC-003 R1.

**Question:**

Is protection for a radially-connected transformer protection system energized from the BES considered a transmission Protection System subject to this standard?

**Response:**

The request for interpretation of PRC-004-1 Requirements R1 and R3 focuses on the applicability of the term “transmission Protection System.” The NERC Glossary of Terms Used in Reliability Standards contains a definition of “Protection System” but does not contain a definition of transmission Protection System. In these two standards, use of the phrase transmission Protection System indicates that the requirements using this phrase are applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directly from the BES.

A Protection System for a radially connected transformer energized from the BES would be considered a transmission Protection System and subject to these standards only if the protection trips an interrupting device that interrupts current supplied directly from the BES and the transformer is a BES element.

**A. Introduction**

- 1. Title:** **Transmission and Generation Protection System Maintenance and Testing**
- 2. Number:** PRC-005-1.1b
- 3. Purpose:** To ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested.
- 4. Applicability**
  - 4.1.** Transmission Owner.
  - 4.2.** Generator Owner.
  - 4.3.** Distribution Provider that owns a transmission Protection System.
- 5. Effective Date:** In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements become effective upon Board of Trustee's adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

**B. Requirements**

- R1.** Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:
  - R1.1.** Maintenance and testing intervals and their basis.
  - R1.2.** Summary of maintenance and testing procedures.
- R2.** Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Entity on request (within 30 calendar days). The documentation of the program implementation shall include:
  - R2.1.** Evidence Protection System devices were maintained and tested within the defined intervals.
  - R2.2.** Date each Protection System device was last tested/maintained.

**C. Measures**

- M1.** Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System that affects the reliability of the BES, shall have an associated Protection System maintenance and testing program as defined in Requirement 1.
- M2.** Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System that affects the reliability of the BES, shall have evidence it provided documentation of its associated Protection System maintenance and testing program and the implementation of its program as defined in Requirement 2.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Regional Entity.

**1.2. Compliance Monitoring Period and Reset Time Frame**

One calendar year.

**1.3. Data Retention**

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System, shall retain evidence of the implementation of its Protection System maintenance and testing program for three years.

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

**1.4. Additional Compliance Information**

The Transmission Owner and any Distribution Provider that owns a transmission Protection System and the Generator Owner that owns a generation or generator interconnection Facility Protection System, shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

**2. Violation Severity Levels (no changes)**

**E. Regional Differences**

None identified.

**Version History**

<b>Version</b>	<b>Date</b>	<b>Action</b>	<b>Change Tracking</b>
0	April 1, 2005	Effective Date	New
1	December 1, 2005	<ol style="list-style-type: none"> <li>1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>2. Added “periods” to items where appropriate.</li> <li>3. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> </ol>	01/20/05
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected	Project 2009-17 interpretation

**Standard PRC-005-1.1b — Transmission and Generation Protection System Maintenance and Testing**

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		transformers	
1a	February 17, 2011	Adopted by Board of Trustees	
1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC's Order is effective as of September 26, 2011)	
1.1a	February 1, 2012	Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner's responsibility	Revision under Project 2010-07
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC's Order dated March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
1.1b	April 23, 2012	Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.	Revision under Project 2010-07
1.1b	May 9, 2012	Adopted by Board of Trustees	



## Appendix 1

Requirement Number and Text of Requirement
<p><b>R1.</b> Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:</p> <p><b>R1.1.</b> Maintenance and testing intervals and their basis.</p> <p><b>R1.2.</b> Summary of maintenance and testing procedures.</p> <p><b>R2.</b> Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include:</p> <p><b>R2.1</b> Evidence Protection System devices were maintained and tested within the defined intervals.</p> <p><b>R2.2</b> Date each Protection System device was last tested/maintained.</p>
<b>Question:</b>
Is protection for a radially-connected transformer protection system energized from the BES considered a transmission Protection System subject to this standard?
<b>Response:</b>
<p>The request for interpretation of PRC-005-1 Requirements R1 and R2 focuses on the applicability of the term “transmission Protection System.” The NERC Glossary of Terms Used in Reliability Standards contains a definition of “Protection System” but does not contain a definition of transmission Protection System. In these two standards, use of the phrase transmission Protection System indicates that the requirements using this phrase are applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directly from the BES.</p> <p>A Protection System for a radially connected transformer energized from the BES would be considered a transmission Protection System and subject to these standards only if the protection trips an interrupting device that interrupts current supplied directly from the BES and the transformer is a BES element.</p>

## Appendix 2

<b>Requirement Number and Text of Requirement</b>
<p><b>R1.</b> Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:</p> <p><b>R1.1.</b> Maintenance and testing intervals and their basis.</p> <p><b>R1.2.</b> Summary of maintenance and testing procedures.</p>
<p><b>Question:</b></p> <ol style="list-style-type: none"><li>1. Does R1 require a maintenance and testing program for the battery chargers for the “station batteries” that are considered part of the Protection System?</li><li>2. Does R1 require a maintenance and testing program for auxiliary relays and sensing devices? If so, what types of auxiliary relays and sensing devices? (i.e transformer sudden pressure relays)</li><li>3. Does R1 require maintenance and testing of transmission line re-closing relays?</li><li>4. Does R1 require a maintenance and testing program for the DC circuitry that is just the circuitry with relays and devices that control actions on breakers, etc., or does R1 require a program for the entire circuit from the battery charger to the relays to circuit breakers and all associated wiring?</li><li>5. For R1, what are examples of "associated communications systems" that are part of “Protection Systems” that require a maintenance and testing program?</li></ol>
<p><b>Response:</b></p> <ol style="list-style-type: none"><li>1. While battery chargers are vital for ensuring “station batteries” are available to support Protection System functions, they are not identified within the definition of “Protection Systems.” Therefore, PRC-005-1 does not require maintenance and testing of battery chargers.</li><li>2. The existing definition of “Protection System” does not include auxiliary relays; therefore, maintenance and testing of such devices is not explicitly required. Maintenance and testing of such devices is addressed to the degree that an entity’s maintenance and testing program for 3 DC control circuits involves maintenance and testing of imbedded auxiliary relays. Maintenance and testing of devices that respond to quantities other than electrical quantities (for example, sudden pressure relays) are not included within Requirement R1.</li><li>3. No. “Protective Relays” refer to devices that detect and take action for abnormal conditions. Automatic restoration of transmission lines is not a “protective” function.</li><li>4. PRC-005-1 requires that entities 1) address DC control circuitry within their program, 2) have a basis for the way they address this item, and 3) execute the program. PRC-005-1 does not establish specific additional requirements relative to the scope and/or methods included within the program.</li><li>5. “Associated communication systems” refer to communication systems used to convey essential Protection System tripping logic, sometimes referred to as pilot relaying or teleprotection. Examples include the following:<ul style="list-style-type: none"><li>• communications equipment involved in power-line-carrier relaying</li><li>• communications equipment involved in various types of permissive protection system</li></ul></li></ol>

applications

- direct transfer-trip systems
- digital communication systems (which would include the protection system communications functions of standard IEC 618501 as well as various proprietary systems)

A. Introduction

1. **Title:** Transmission and Generation Protection System Maintenance and Testing
2. **Number:** PRC-005-1.1b
3. **Purpose:** To ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested.
4. **Applicability**
  - 4.1. Transmission Owner.
  - 4.2. Generator Owner.
  - 4.3. Distribution Provider that owns a transmission Protection System.

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

~~B. Requirements~~

~~5. **R1-Effective Date:** In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements become effective upon Board of Trustee's adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

B. Requirements

**R1.** Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:

- R1.1.** Maintenance and testing intervals and their basis.
- R1.2.** Summary of maintenance and testing procedures.

**R2.** Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization~~Entity~~ on request (within 30 calendar days). The documentation of the program implementation shall include:

- R2.1.** Evidence Protection System devices were maintained and tested within the defined intervals.
- R2.2.** Date each Protection System device was last tested/maintained.

C. Measures

**M1.** Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System that affects the reliability of the BES, shall have an associated Protection System maintenance and testing program as defined in Requirement 1.

- M2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System that affects the reliability of the BES, shall have evidence it provided documentation of its associated Protection System maintenance and testing program and the implementation of its program as defined in Requirement 2.

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Monitoring Responsibility

Regional ~~Reliability Organization~~Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

#### 1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System, shall retain evidence of the implementation of its Protection System maintenance and testing program for three years.

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

#### 1.4. Additional Compliance Information

The Transmission Owner and any Distribution Provider that owns a transmission Protection System and the Generator Owner that owns a generation or generator interconnection Facility Protection System, shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

### 2. Violation Severity Levels of Non-Compliance(no changes)

~~2.1. Level 1: Documentation of the maintenance and testing program provided was incomplete as required in R1, but records indicate maintenance and testing did occur within the identified intervals for the portions of the program that were documented.~~

~~2.2. Level 2: Documentation of the maintenance and testing program provided was complete as required in R1, but records indicate that maintenance and testing did not occur within the defined intervals.~~

~~2.3. Level 3: Documentation of the maintenance and testing program provided was incomplete, and records indicate implementation of the documented portions of the maintenance and testing program did not occur within the identified intervals.~~

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

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	<ol style="list-style-type: none"> <li>1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>2. Added “periods” to items where appropriate.</li> <li>3. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> </ol>	01/20/05
<del>1</del>	<del>February 7, 2006</del>	<del>Adopted by NERC Board of Trustees</del>	
<del>1a</del>	<del>November 5, 2009</del>	<del>Interpretation of R1, R1.1, and R1.2 adopted by the NERC Board of Trustees</del>	<del>Project 2009-10 Interpretation</del>
1a	February 17, 2011	<u>Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers</u> <del>adopted by the NERC Board of Trustees (adopted and filed as 1a instead of 1b)</del>	Project 2009-17 <u>Interpretation</u>
<u>1a</u>	<u>February 17, 2011</u>	<u>Adopted by Board of Trustees</u>	
1a	September 26, 2011	<del>FERC Order issued approving interpretation regarding applicability of standard to protection of radially connected transformers of R1 and R2</del> (FERC’s Order is effective as of September 26, 2011)	<del>Project 2009-17 Interpretation</del>
<u>1.1a</u>	<u>February 1, 2012</u>	<u>Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility</u>	<u>Revision under Project 2010-07</u>
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC’s Order <del>is effective as of</del> dated March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
<u>1.1b</u>	<u>April 23, 2012</u>	<u>Updated standard version to 1.1b to reflect</u>	<u>Revision under Project</u>

Standard PRC-005-1.1b — Transmission and Generation Protection System Maintenance and Testing

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		<u>FERC approval of PRC-005-1b.</u>	<u>2010-07</u>
<u>1.1b</u>	<u>May 9, 2012</u>	<u>Adopted by Board of Trustees</u>	

## Appendix 1

Requirement Number and Text of Requirement
<p><b>R1.</b> Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:</p> <p><b>R1.1.</b> Maintenance and testing intervals and their basis.</p> <p><b>R1.2.</b> Summary of maintenance and testing procedures.</p> <p><b>R2.</b> Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include:</p> <p><b>R2.1</b> Evidence Protection System devices were maintained and tested within the defined intervals.</p> <p><b>R2.2</b> Date each Protection System device was last tested/maintained.</p>
<b>Question:</b>
Is protection for a radially-connected transformer protection system energized from the BES considered a transmission Protection System subject to this standard?
<b>Response:</b>
<p>The request for interpretation of PRC-005-1 Requirements R1 and R2 focuses on the applicability of the term “transmission Protection System.” The NERC Glossary of Terms Used in Reliability Standards contains a definition of “Protection System” but does not contain a definition of transmission Protection System. In these two standards, use of the phrase transmission Protection System indicates that the requirements using this phrase are applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directly from the BES.</p> <p>A Protection System for a radially connected transformer energized from the BES would be considered a transmission Protection System and subject to these standards only if the protection trips an interrupting device that interrupts current supplied directly from the BES and the transformer is a BES element.</p>





## Appendix 2<sup>†</sup>

Requirement Number and Text of Requirement
<p><b>R1.</b> Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:</p> <p><b>R1.1.</b> Maintenance and testing intervals and their basis.</p> <p><b>R1.2.</b> Summary of maintenance and testing procedures.</p>
<p><b>Question #1:</b></p> <p><del>Does R1 require a maintenance and testing program for the battery chargers for the “station batteries” that are considered part of the Protection System?</del></p>
<p><b>Response to Question #1</b></p> <p><del>While battery chargers are vital for ensuring “station batteries” are available to support Protection System functions, they are not identified within the definition of “Protection Systems.” Therefore, PRC 005-1 does not require maintenance and testing of battery chargers.</del></p>
<p><b>Question #2</b></p> <p><del>Does R1 require a maintenance and testing program for auxiliary relays and sensing devices? If so, what types of auxiliary relays and sensing devices? (i.e. transformer sudden pressure relays)</del></p>
<p><b>Response to Question #2</b></p> <p><del>1. The existing definition Does R1 require a maintenance and testing program for the battery chargers for the “station batteries” that are considered part of “the Protection System” does not include?</del></p> <p><del>2. Does R1 require a maintenance and testing program for auxiliary relays; therefore, maintenance and testing of such and sensing devices is not explicitly required. Maintenance and testing of such? If so, what types of auxiliary relays and sensing devices is addressed to the degree that an entity’s maintenance and testing program for DC control circuits involves? (i.e transformer sudden pressure relays)</del></p> <p><del>3. Does R1 require maintenance and testing of imbedded auxiliary transmission line re-closing relays. Maintenance?</del></p> <p><del>4. Does R1 require a maintenance and testing program for the DC circuitry that is just the circuitry with relays and devices that control actions on breakers, etc., or does R1 require a program for the entire circuit from the battery charger to the relays to circuit breakers and all associated wiring?</del></p>

<sup>†</sup> According to the FERC Order issued approving a modified definition of Protection System (RD11-13-000), this interpretation will be superseded by the modified definition of Protection System when the modified definition becomes effective. The modified definition of Protection System becomes effective on April 1, 2013.

~~5. For R1, what are examples of "associated communications systems" that are part of "Protection Systems" that require a maintenance and testing of devices that respond to quantities other than electrical quantities (for example, sudden pressure relays) are not included within Requirement R1 program?~~

~~Question #3~~

~~Does R1 require maintenance and testing of transmission line re-closing relays?~~

~~Response to Question #3:~~

~~No. "Protective Relays" refer to devices that detect and take action for abnormal conditions. Automatic restoration of transmission lines is not a "protective" function.~~

~~Question #4~~

~~Does R1 require a maintenance and testing program for the DC circuitry that is just the circuitry with relays and devices that control actions on breakers, etc., or does R1 require a program for the entire circuit from the battery charger to the relays to circuit breakers and all associated wiring?~~

~~Response to Question #4~~

~~PRC-005-1 requires that entities 1) address DC control circuitry within their program, 2) have a basis for the way they address this item, and 3) execute the program. PRC-005-1 does not establish specific additional requirements relative to the scope and/or methods included within the program.~~

~~Question #5~~

~~For R1, what are examples of "associated communications systems" that are part of "Protection Systems" that require a maintenance and testing program?~~

~~Response to Question #5~~

- ~~1. While battery chargers are vital for ensuring "station batteries" are available to support Protection System functions, they are not identified within the definition of "Protection Systems." Therefore, PRC-005-1 does not require maintenance and testing of battery chargers.~~
- ~~2. The existing definition of "Protection System" does not include auxiliary relays; therefore, maintenance and testing of such devices is not explicitly required. Maintenance and testing of such devices is addressed to the degree that an entity's maintenance and testing program for 3 DC control circuits involves maintenance and testing of imbedded auxiliary relays. Maintenance and testing of devices that respond to quantities other than electrical quantities (for example, sudden pressure relays) are not included within Requirement R1.~~
- ~~3. No. "Protective Relays" refer to devices that detect and take action for abnormal conditions. Automatic restoration of transmission lines is not a "protective" function.~~
- ~~4. PRC-005-1 requires that entities 1) address DC control circuitry within their program, 2) have a basis for the way they address this item, and 3) execute the program. PRC-005-1 does not establish specific additional requirements relative to the scope and/or methods included within the program.~~

“Associated communication systems” refer to communication systems used to convey essential  
5. Protection System tripping logic, sometimes referred to as pilot relaying or teleprotection. Examples include the following:

- communications equipment involved in power-line-carrier relaying
- communications equipment involved in various types of permissive protection system applications
- direct transfer-trip systems
- digital communication systems (which would include the protection system communications
- functions of standard IEC 618501 as well as various proprietary systems)

**Exhibit C**

**Technical Justification Resource Document**

# Technical Justification Resource Document

Project 2010-07 Generator Requirements at the Transmission Interface

Updated July 16, 2012

## I. Background

As part of its work on Project 2010-07—Generator Requirements at the Transmission Interface, the standard drafting team (SDT) reviewed 34 Reliability Standards and 102 requirements to determine what changes are necessary to close a reliability gap with respect to what is commonly known as the generator interconnection Facility. Many of these standards and requirements had been addressed in the [Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface](#) (Ad Hoc Report) and additional standards were reviewed as a result of discussions with NERC and FERC staffs.

The basis for standard modifications recommended by the Ad Hoc Group for Generator Requirements at the Transmission Interface (Ad Hoc Group) was a few fundamental clarifications to the definitions of Generator Owner, Generator Operator, and Transmission, along with the creation of new definitions: one for Generator Interconnection Facility and one for Generator Interconnection Operational Interface. The Ad Hoc Group proposed the addition of these two new definitions to 26 standards encompassing 29 requirements (new and old), along with some modifications to FAC-003 to make it applicable to Generator Owners under certain circumstances.

Since the publication of the Ad Hoc Report, various entities have challenged these modifications and the recommended creation of the new definitions. Given this, the SDT began efforts to address those standards that required modification to address the majority of interconnection Facilities and developed a more focused approach than that of the Ad Hoc Group: to propose recommendations whereby sole-use interconnection Facilities (at or above 100 kV) that are owned and operated by generating entities will be included in a small set of standards and requirements previously only applicable to Transmission Owners. The SDT agrees completely with the Ad Hoc Group's conclusion that Generator Owners and Operators of the majority of sole-use generator interconnection Facilities (at voltages equal to or greater than 100 kV) should not be registered as Transmission Owners and Transmission Operators in order to maintain reliability on the Bulk Electric System (BES). From the beginning, the SDT emphasized that a majority of generator interconnection Facilities consist of one or two lines interconnecting with a Transmission Owner's Facility, and the SDT believes that the majority of these Facilities are best addressed using the focused approach outlined below.

The SDT's justification for this strategy is rooted in the very title of its standards project: "Generator Requirements at the Transmission Interface." That is, the goal and scope of the project has always

been to determine the responsibilities of those Generator Owners and Generator Operators that own or operate an interconnection Facility (in some cases labeled a “transmission Facility”) between the generator and the interface with the portion of the BES where Transmission Owners and Transmission Operators take over ownership and operating responsibility. These kinds of Generator Owners and Generator Operators do not own or operate Facilities that are part of the interconnected system; rather, they own and operate sole-use Facilities that are connected to the boundary of the interconnected system and as such have a limited role in providing reliability compared to those that operate in a networked fashion beyond the point of interconnection.

While some argue that these interconnecting portions of a Generator Owner’s Facilities could be defined as “Transmission” and thus require the Generator Owner and Generator Operator for the Facility to be classified and registered as a Transmission Owner and Transmission Operator, the SDT does not believe this is necessary to provide an appropriate level of reliability for the BES. Just as important, such classification and registration could actually cause a reduction in reliability. Generator Owners and Generator Operators do not need, and in some cases may be prohibited from having, a wide-area view and responsibility for the integrated transmission system. Requiring Generator Owners and Generator Operators to have such responsibilities would require significant training, require substantially more data and modeling responsibilities, and detract from the entities’ primary functions: to own and operate their generation equipment – including any Facilities owned and operated at voltages of 100 kV or greater that connect to the interconnected system – in a reliable manner.

Additionally, the SDT believes that the industry is much more aware today of the need to include *all* elements (owned and operated at 100 kV or higher) of a generator Facility in the procedures and compliance program of the registered entity that owns or has operational responsibility of those elements. Industry awareness was raised substantially at the time the [October 17, 2010 Facility Ratings Recommendation to Industry](#) was issued (which included Generator Owners and specifically addressed interconnection Facilities in [the Q&A document](#) with the statement that the alert applied to generator interconnection tie lines that are radial only and do not serve load “if the generator is considered part of the bulk electric system”). While this applies to a specific NERC Recommendation, the SDT considers this compelling evidence that the paradigm for thinking about generator interconnection Facilities is shifting.

All of this has led the SDT to its current conclusions to modify FAC-001, FAC-003, PRC-004, and PRC-005. The SDT does not believe any further modifications to standards are necessary to maintain an appropriate level of reliability based on the revised assumption that while generator Facilities (at 100 kV and above) will be considered by some to be transmission, Generator Owners and Generator Operators should not be registered as Transmission Owners and Transmission Operators simply as a result of the ownership and operation of such Facilities. Because the majority of commenters support the SDT’s current recommendation to not adopt new terms, the SDT has elected to focus on its standard changes and not propose revisions to existing, or creation of new, glossary terms.

Below, the SDT discusses the changes it has proposed for FAC-001, FAC-003, PRC-004, and PRC-005 and then provides justification for not modifying any of the additional standards and requirements it has reviewed.

## II. Review of SDT's Proposed Standard Changes

### ***FAC-001-1—Facility Connection Requirements***

While some stakeholders have questioned the modifications in the proposed FAC-001-1, the SDT remains convinced that there is the potential for a reliability gap if this standard is not modified so that it applies to a Generator Owner *if and when it executes an Agreement* to evaluate the reliability impact of interconnecting a third party Facility to its existing generation interconnection Facility. The intent of this modified language is to start the compliance clock when the Generator Owner executes an Agreement to perform the reliability assessment required in FAC-002-1. This step is expected to occur if a Generator Owner is compelled by a regulatory body to allow such interconnection. Assuming that a regulatory body would require a Generator Owner to evaluate such an interconnection request, the SDT expects the Generator Owner and the third party to execute some form of an Agreement. The SDT intentionally excluded a specific reference to the form of Agreement (such as a feasibility study) in deference to stakeholder suggestions to avoid comingling of commercial and reliability issues in Reliability Standards.

The SDT acknowledges that the scenario described in the proposed FAC-001-1 may be rare, but in the past (*e.g., Alta Wind I, LLC et al.*, 134 FERC ¶ 61,109 at P 19 (2011) and *Sky River, LLC*, 134 FERC ¶ 61,064 at P 13 (2011)), Generator Owners have received or have been directed to execute interconnection requests for their Facilities, and the SDT thinks it is important to clarify the responsibilities related to such a request in NERC's Reliability Standards. And, while the SDT acknowledges that such regulatory action might also result in the Generator Owner being registered for other functions, such as Transmission Owner, Transmission Planner, and/or Transmission Service Provider, it decided the proposed revision provides appropriate reliability coverage until any additional registration is required and does not impact any Generator Owner that never executes an Agreement as described in the standard.

### ***FAC-003-3—Transmission Vegetation Management***

The SDT and most stakeholders agree with the Ad Hoc Group recommendation that FAC-003 be applicable to Generator Owners that own a generation interconnection Facility if that Facility contains overhead conductors. The Ad Hoc Group originally excluded such a Facility from this requirement if its length is less than two spans (generally one half mile from the generator property line). The SDT agrees with that intended exclusion in principle; as it discusses in the document titled "[Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface](#)," the SDT recognizes that in many cases, generation Facilities are (1) staffed and the overhead portion is within



line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale for exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit.

Thus, the SDT has maintained this exception language but has modified it based on stakeholder input such that it excludes Facilities shorter than one mile which have a clear line of sight from the fenced area of the generating switchyard to the point of interconnection. Specifically, section 4.3.1 of FAC-003-3 (which addresses applicable generation Facilities) now states: “Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner’s Facility or (2) do not have a clear line of sight from the generating station switchyard fence to the point of interconnection with a Transmission Owner’s Facility...” The SDT took into consideration all comments submitted in both formal comment periods, and believes that this exemption now adequately addresses the reliability impact for a majority of the Facilities, while balancing the efforts necessary to support the standard from all entities.

#### ***PRC-004-2.1a—Analysis and Mitigation of Transmission and Generation Protection System Misoperations***

After examining all standards it had previously reviewed, the SDT elected to propose a slight change to PRC-004-2a. The SDT recognizes that generator interconnection Facilities are now widely recognized in the industry as the responsibility of Generator Owners and Generator Operators. While the SDT rejected other opportunities to “drop” the phrase “generator interconnection Facility” into requirements because it is not typically the best way to add clarity, in the case of PRC-004-2a, the SDT believes that the phrasing of R2 (“The Generator Owner shall analyze its generator Protection System Misoperations...”) could lead to some confusion about whether an interconnection Facility is included. Thus, the SDT proposes adding “and generator interconnection Facility” as redlined in the draft standard. Because there is no change in applicability, and because the SDT believes that most Generator Owners already interpret the standard in this manner, the SDT considers this proposed change, reflected in PRC-004-2.1a, to be a minor and not substantive change employed only to add clarity.

#### ***PRC-005-1.1b—Transmission and Generation Protection System Maintenance and Testing***

In the concurrent 45-day comment and ballot period that ended in November 2011, several commenters pointed out that the wording in R1 (“...and each Generator Owner that owns a generation Protection System...”) and R2 (“...and each Generator Owner that owns a generation Protection System...”) of PRC-005-1b requires the same explicit reference to a generator interconnection Facility that was added in the proposed PRC-004-2.1a R2. The SDT agreed and modified both R1 and R2 to add “and generator interconnection Facility” as redlined in the draft standard, PRC-005-1.1b.

**III. Review of Other Standards Considered by the Standard Drafting Team**

To ensure that no reliability gaps were left when the SDT shifted its strategy from the original strategy of the Ad Hoc Group, the SDT reviewed all standards for which the Ad Hoc Group had proposed changes, and again discussed whether making these standards applicable to Generator Owners or Generator Operators would increase reliability with respect to generator requirements at the transmission interface. During the 45-day concurrent comment and ballot period that ended in November 2011, stakeholder commenters encouraged the SDT to review standards cited in FERC’s Order denying the registry appeals of Cedar Creek Wind Energy, LLC and Milford Wind Corridor Phase I, LLC (135 FERC ¶ 61,241 (2011)) (June 16 FERC Order).

The SDT reviewed all of these standards and requirements again and continues to find clear and technical reliability-based reasons that support not adding Generator Owner and Generator Operator requirements to the standards. The chart below indicates where (*i.e.*, the Ad Hoc Report, or the June 16 FERC Order) the standards addressed were discussed. While the FERC Orders address specific requirements within these standards, the SDT has found it useful to address each standard as a whole. Often, requirements within a standard, or even from standard to standard, work in concert to ensure that there are no reliability gaps, whereas a review of a requirement in isolation might give the impression that there is gap.

Reliability Standard	Ad Hoc Report*	June 16 FERC Order	SDT Proposal
EOP-003-1	X		
EOP-005-1			
FAC-001-0			X
FAC-003-1 or FAC-003-2	X	X	X
FAC-014-2		X	
IRO-005-2	X		
PER-001-0	X		
PER-002-0	X		
PER-003-1		X	
PRC-001-1		X	
PRC-004-1, PRC-004-1a, or PRC-004-2a		X	X
PRC-005-1a			X
TOP-001-1	X	X	
TOP-004-2	X	X	
TOP-006-1			
TOP-008-1	X		

\*This chart and accompanying document only address those standards in the Ad Hoc Report for which substantive changes (change in applicability or the addition of a new requirement) were proposed.

The SDT acknowledges that FERC has stated that the June 16 FERC Order is not intended to prejudice the work of the SDT. *See Cedar Creek Wind Energy, LLC et al.*, 137 FERC ¶ 61,141 at P 26 (2011) (“these proceedings do not prejudice NERC’s ongoing effort.”). The SDT also acknowledges that the discussion in the June 16 FERC Order is related to specific cases in which certain entities will actually be registered as Transmission Owners and Transmission Operators, a process that is distinct from the SDT’s work, which assumes that once this project is complete, Generator Owners and Generator Operators will not be automatically registered for any other functions based solely on ownership of a sole-use generator interconnection facility. The rest of this document provides the SDT’s technical justification for limiting the scope of its work to FAC-001, FAC-003, PRC-004, and PRC-005.

***EOP-003-1—Load Shedding Plans (addressed in the Ad Hoc Report)***

For EOP-003-1, the Ad Hoc Group originally proposed that Generator Operators be added to the requirement that requires Transmission Operators and Balancing Authorities to coordinate automatic load-shedding throughout their areas. The SDT determined that this addition was unnecessary because PRC-001-1 already includes the requirement that Transmission Operators coordinate their underfrequency load shedding programs with underfrequency isolation of generating units, which indicates that Generator Operators need to provide their underfrequency settings to their respective Transmission Operator. Since there would be no load to shed on sole-use generator interconnection Facilities, there would be no role for the Generator Operator regardless of whether the Generator Operator is required to comply with this standard or register as a Transmission Operator for the sole-use generator interconnection Facilities. Further, Generator Operators typically do not have the technical expertise or access to the data necessary for the high-level coordination that this standard requires.

***EOP-005-1—System Restoration Plans***

The SDT considered the application of EOP-005-1 Requirements R1, R2, R5, R6, and R7 to Generator Operators. The SDT concluded that EOP-005 does not need to be modified under Project 2010-07, largely because EOP-005-2 has already been revised (and approved by FERC)<sup>1</sup> to incorporate generator requirements, but also for the additional reasons outlined below.

Blackstart capability of a generating unit is unrelated to owning or operating transmission Facilities or a generation interconnection Facility. During a system restoration event, Generator Operators provide real and reactive power to the BES only at the direction of a Transmission Operator. The Generator

<sup>1</sup> See *System Restoration Reliability Standards*, Order No. 749, 134 FERC ¶ 61,215 (2011).

Operators are not providing Transmission Operator services through their blackstart Facilities. In addition, many units with blackstart capability are not included in a TOP System Restoration Plan.

Further, the SDT does not believe that the restoration of a single line or Facility is intended by the purpose statement of EOP-005, which reads: “To ensure plans, procedures, and resources are available to restore the electric system to a normal condition in the event of a partial or total shut down of the system” (emphasis added).

In Order No. 693, at paragraph 630, FERC approved EOP-005-1 and found that the standard:

adequately addresses operating personnel training and system restoration plans to ensure that transmission operators, balancing authorities and reliability coordinators are prepared to restore the Interconnection following a blackout. Accordingly, the Commission approves Reliability Standard EOP- 005-1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP-005-1 through the Reliability Standards development process that identifies time frames for training and review of restoration plan requirements...

FERC also specifically addressed system restoration training concerns and requirements in Order No. 693 in its review and approval of Reliability Standard EOP-005-1. In that order, FERC stated (at P 627) that personnel outside a control room should be trained in system restoration, but also that this should be included in a system restoration Reliability Standard, as follows:

627. With regard to comments that the Commission’s concerns are being addressed in NERC’s drafting of proposed PER-005-1 Reliability Standard on operator training, we note PER-005-1 only includes Requirements on the control room personnel and not those outside of the control room. System restoration requires the participation of not only control room personnel but also those outside of the control room. These include blackstart unit operators and field switching operators in situations where SCADA capability is unavailable. As such, the Commission believes that inclusion of periodic system restoration drills and training and review of restoration plans in a system restoration Reliability Standard is the most effective way of achieving the desired goal of ensuring that all participants are trained in system restoration and that the restoration plans are up to date to deal with system changes.

Thus, FERC clearly found that the existing standard EOP-005-1 adequately addressed operating personnel training and would ensure the restoration of the BES in the event of a blackout, and further directed that any modifications be addressed through the Reliability Standard Development Process.

Pursuant to Order No. 693, NERC initiated Project 2006-03, and empowered the System Restoration and Blackstart Standard Drafting Team (SRBSDT) to modify the related standards. The SRBSDT developed Reliability Standard EOP-005-2, which includes Generator Operator requirements for agreements and procedures related to system restoration. In Order 749, FERC approved EOP-005-2, which included its approval of the implementation plan for EOP-005-2.<sup>2</sup>

5. Currently effective Reliability Standard EOP-005-1 requires transmission operators, balancing authorities, and reliability coordinators to have a restoration plan, test the plan, train operating personnel in the restoration plan, and have the ability to restore the Interconnection using the plans following a blackout. In Order No. 693, the Commission directed the ERO to develop, through the Reliability Standard development process, a modification to EOP-005-1 that identifies time frames for training and review of restoration plan requirements to simulate contingencies and prepare operators for anticipated and unforeseen events . . .<sup>3</sup>

Also, in FERC Order No. 749 (at PP 10, 17), both NERC and FERC identified the modifications to EOP-005 as “improvements” to the standard, not changes necessary to close a reliability gap:

10. NERC states that the proposed Reliability Standards “represent significant revision and improvement from the current set of enforceable standards” and address the Commission’s directives in Order No. 693 related to the EOP standards. NERC explains that, among other enhancements, “[t]he proposed revisions now clearly delineate the responsibilities of the Reliability Coordinator and Transmission Operator in the restoration process and restoration planning.” NERC describes the proposed Reliability Standards as providing “specific requirements for what must be in a restoration plan, how and when it needs to be updated and approved, what needs to be provided to operators and what training is necessary for personnel involved in restoration processes. (internal citations omitted)

17. . . . By enhancing the rigor of the restoration planning process, the Reliability Standards represent an improvement from the current Standards and will improve the reliability of the Bulk-Power System. . . .

In summary, the Generator Operator blackstart requirements have already been appropriately addressed through the Reliability Standards Development Process. EOP-005-2 will become effective in 2013 as approved by both the NERC Board of Trustees and FERC. There is no existing reliability gap related to owning a generation interconnection Facility and Standard EOP-005-1.

<sup>2</sup> [http://www.nerc.com/docs/standards/sar/SRBSDT\\_Implementation\\_Plan\\_Clean\\_Preballot\\_Review\\_2009March03.pdf](http://www.nerc.com/docs/standards/sar/SRBSDT_Implementation_Plan_Clean_Preballot_Review_2009March03.pdf)

<sup>3</sup> Order No. 749 at P 5.

***FAC-014-2—Establish and Communicate System Operating Limits (addressed in the June 16 FERC Order)***

FAC-014-2, R2 states “The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator’s SOL Methodology.”

In paragraph 68 of the June 16 FERC Order, FERC states that without compliance with FAC-014, R2, the entity in question could “avoid establishing the system operating limit for its line or be allowed to establish an operating limit for its line that is not consistent with the requirements of the reliability coordinator’s methodology.” (internal citation omitted). *See also* June 16 FERC Order at P 84.

The SDT does not believe that FAC-014-2 R2 should be revised to include Generator Operators. The Generator Owner is required by the FERC-approved versions of FAC-008-1 R1 and FAC-009-1 and pending FAC-008-3 R1, R2, and R6 (which has been filed for approval with FERC) to document the Facility Ratings for a Generator Owner-owned generator interconnection circuit greater than 100kV. The established Facility Rating must respect the most limiting applicable equipment rating in the circuit and must consider operating limitations and ambient conditions. The thermal or ampere rating of this circuit would equal its ampere operating limit and should be conveyed by the Generator Owner to the Generator Operator if they are not the same entity. The operating voltage limits for this circuit are established by the applicable interconnecting Transmission Owner or Transmission Operator, not the Generator Owner or Generator Operator.

Therefore, the SDT believes that adding the Generator Owner to FAC-014-2 R2 would be redundant. Moreover, the SDT is concerned that entities with limited view (only their Facility) should not be responsible for setting IROLs or SOLs as these are interconnection and system limits. The SDT believes this should be the responsibility of entities with a wide-area view, as shown in the standard today; otherwise, the SDT is concerned that reliability may be jeopardized. Commenters – including one from the Transmission Owner segment – have offered this same justification.

***IRO-005-2—Reliability Coordination – Current Day Operations (addressed in the Ad Hoc Report and since retired...see IRO-005-3a and BOT-approved IRO-005-4)***

The drafting team considered the applicability of this standard to generator entities, but PRC-001-1, Requirement 2, already requires the Generator Operator to notify reliability entities of relay or equipment failures. The drafting team believes that a Special Protection System is a form of protection system and therefore any degradation or potential failure to operate as expected would be required to be reported by the Generator Operator to reliability entities (Balancing Authorities, Transmission Operators, and Reliability Coordinators). Modifying this standard would not have been necessary, but IRO-005-2 was retired in October 2011 and replaced by IRO-005-3a. IRO-005-3a does still include a requirement related to Special Protection Systems, but as with IRO-005-2, Generator Operators do not need to be added to the standard because their handling of protection systems is already addressed in

PRC-001-1, Requirement R2. IRO-005-3a will be retired when IRO-005-4 (approved by NERC's Board of Trustees in August 2011) is approved, and IRO-005-4 has no requirements relating to Special Protection Systems. IRO-010-1a will then be the sole standard to cover those issues, in Requirements R1 and R3. While those requirements do not specifically mention Special Protection Systems, they relate to the "data specification for data and information to building and maintain models to support Real-Time monitoring, Operational Planning Analyses, and Real-Time Assessments." If there are Special Protection Systems that exist and they impact the BES, then the Reliability Coordinator will be asking for the status and the Generator Owner or Generator Operator will be providing it.

***PER Standards (PER-001-0 and PER-002-0 were addressed in the Ad Hoc Report; and PER-003-1 was addressed in the June 16 FERC Order)***

The Ad Hoc Group had proposed changes to PER-001-0—Operating Personnel Responsibility and Authority and PER-002-0—Operating Personnel Training. For PER-001-0, the Ad Hoc Group proposed adding a new R2 that would read "Each Generator Operator shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Generation Facility and Generation Interconnection Facility, and the responsibility and authority to follow the directives of reliability authorities including the Transmission Operator and Balancing Authority." To PER-002-0, the Ad Hoc Group proposed adding the Generator Operator to R1 ("Each Transmission Operator, Generator Operator, and Balancing Authority shall be staffed with adequately trained operating personnel") and adding a new R3 that would read: "Each Generator Operator shall implement an initial and continuing training program for all operating personnel that are responsible for operating the Generation Interconnection Facility that verifies the personnel's ability and understanding to operate the equipment in a reliable manner."

These proposed changes to the PER standards have little to do with responsibilities that relate specifically to a generator interconnection Facility. Issues related to the training of Generator Operators existed separately from the work of Project 2010-07, and the SDT finds that its scope limits its efforts to standards that are directly related to generator requirements at the transmission interface. The SDT also cites past FERC Orders as proof that this issue is not within the scope of Project 2010-07. In Order No. 693 (at P 1393), FERC directed NERC to expand the applicability of the personnel training Reliability Standard, PER-002-0, to include (i) generator operators centrally-located at a generation control center with a direct impact on the reliable operation of the Bulk-Power System..." In Order No. 742, FERC reaffirmed this, stating that it is "not modifying the Order No. 693 directive regarding training for certain generator operator dispatch personnel, nor are we expanding a generator operator's responsibilities."

Centrally-located generator operators working at a generation control center typically dispatch the output from multiple generating units. As such, they can be called upon to comply with orders from their Balancing Authority that may have a significant impact on the reliable operation of the BES. Their



training would be covered by proposed changes to PER-002-0 and Order No. 742. Generator Operators who deal with interconnection Facilities at individual generating plants, on the other hand, typically do not receive reliability-based orders specific to the interconnection Facilities and are therefore not covered by Order 742. Further, the SDT believes there is no reliability gap as TOP-001-1 R3 already requires Generator Operators to follow the directives of the appropriate Transmission Operators.

These training-related items are clearly important ones for the Commission, but the SDT does not think it is appropriate to fold modifications to these PER standards into the scope of its work unless it is specifically directed to do so. For now, modifications to PER-002-0 based on Order No. 693 directives are already included in [NERC's Issue Database](#) (P. 52-53) to be addressed by a future project. PER-001-0 is not addressed in the Issues Database, but the [Project 2007-03 drafting team has proposed](#) that the standard be retired.

The June 16 FERC Order does not address PER-001-0 or PER-002-0, but it does address PER-003-1. In paragraphs 67 and 81 of the June 16 FERC Order, FERC expresses concern that operational control over the transmission line breakers owned by the entities in question are not under the control of NERC certified operators. FERC states (at P 67) that "Reliability Standard PER-003-001 requires NERC certification of all operators that have responsibility for the real-time operation of the interconnected Bulk Electric System. When switching the tie-line in or out of service, operators must have the appropriate credentials and training to properly perform the switching and coordinate the switching to prevent adverse impacts such as the introduction of faults on the system."

The SDT polled generator and transmission forum members and found that the vast majority have an existing qualification process for personnel who perform switching. The team also found that although most field personnel who actually perform the switching of an Element or Facility are not NERC certified, they do receive authorization (either directly from a NERC certified system operator or through an intermediary) just prior to executing the switching to take an Element or Facility out of service or place it into service.

The SDT can find no evidence that the kinds of training requirements for operating the breakers of the generator interconnection Facility cited in the June 16 FERC Order exist elsewhere for other entities that operate breakers on lines. For instance, Transmission Owners that are not also Transmission Operators are not required to undergo any sort of training.

***PRC-001-1—System Protection Coordination (addressed in the June 16 FERC Order)***

The June 16 FERC Order addresses PRC-001-1 R2, R2.2, R4 and R6. PRC-001-R2 requires notification and corrective action for relay or equipment failure. Requirement R4 requires coordination of protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.



In paragraphs 64 and 78 of the June 16 FERC Order, FERC expresses concern that “there is a risk of an adverse impact on reliability if the protection relays or protection systems on the [entity’s] line are not coordinated with those on the transmission network facilities in its area.”(internal citation omitted).

Generator Operators and the scope of protection equipment for generation interconnection Facilities are already appropriately accounted for in this standard in requirement R2 and sub-requirement R2.2. The language used in R2 that applies to the Generator Operator uses the general terms “relay or equipment failures” which would include not only generator relaying, but generator interconnection relaying, in the Generator Operator’s scope as well. The Generator Operator is required to notify the Transmission Operator and Host Balancing Authority in R2.1 “if a protective relay or equipment failure reduces system reliability.” Requirement R2.2 requires the affected Transmission Operator to notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. Thus, applying R2.2 to a Generator Operator would be redundant to R2.1. If a Generator Operator had a relay or equipment failure on its Facility, including its interconnection Facility, it would be required to report that to its interconnected Transmission Operator under R2.1. That Transmission Operator is then required to notify its Reliability Coordinator and other affected Transmission Operators and Balancing Authorities under R2.2.

PRC-001-1 R4 states, “Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.” A sole-use generator interconnection Facility does not constitute a major transmission line or major interconnection with neighboring Generator Operators, Transmission Operators, and Balancing Authorities. Thus, R4 should not be revised to include Generator Operators. In general, any coordination that might be required is covered by the fact that the Transmission Operator that is connected to a major transmission line or interconnection has the requirement to coordinate protection on the interconnection, and there is no reliability gap.

PRC-001-1 R6 states, “Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.” It is clearly the responsibility of the Transmission Operator and/or Balancing Authority to monitor the Special Protection System, as they are the entity with a wide-area view, not the responsibility of a Generator Owner/Generator Operator with a local-area view who happens to have generator interconnection Facilities in the area. The requirement focuses on the Transmission Operator and Balancing Authority monitoring the status of each Special Protection System *in their area*; there is no “area” for the Generator Operator to monitor. For these reasons, there is no need to make this requirement applicable to Generator Operators.

***TOP-001-1—Reliability Responsibilities and Authority (addressed in the Ad Hoc Report and June 16 FERC Order)***

The June 16 FERC Order discusses making TOP-001-1 R1 applicable to Generator Operators. With respect to R1, paragraphs 68 and 83 of the June 16 FERC Order focus on ensuring that “system operators have the authority to take actions to maintain Bulk-Power System facilities within operating limits.”

TOP-001-1 R1 states, “Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.” TOP-001-1 R3 appropriately requires the Generator Operator to comply with reliability directives issued by the Transmission Operator “unless such actions would violate safety, equipment, regulatory or statutory requirements.” These requirements effectively give the Transmission Operator the necessary decision-making authority over operation of all generator Facilities up to the point of interconnection. Thus, no changes to TOP-001-1 are necessary.

Additionally, the Ad Hoc Group proposed adding two new requirements to TOP-001-1. The first was proposed as R9 and read: “The Generator Operator shall coordinate the operation of its Generator Interconnection Facility with the Transmission Operator to whom it interconnects in order to preserve Interconnection reliability...” The SDT does not agree that TOP-001-1 needs to apply to Generator Operators in any form. TOP-002-2 R3 (proposed to be covered in the future by TOP-003-2, as outlined in Project 2007-03’s Implementation Plan) already requires the Generator Operator to coordinate its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. These entities are, in turn, required to coordinate with their respective Transmission Operator. Additionally, TOP-002-2 R4 (proposed to be covered in the future by TOP-003-2, as outlined in Project 2007-03’s Implementation Plan) requires each Balancing Authority and Transmission Operator to coordinate with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator. With these requirements, Generator Operators are already required to provide necessary operations information to Transmission Operators. To require the same thing in TOP-001-1 would be redundant.

The second new requirement proposed by the Ad Hoc Group for TOP-001-1 was R10, which was to read: “The Transmission Operator shall have decision-making authority over operation of the Generator Interconnection Operational Interface at all times in order to preserve Interconnection reliability.” As cited above, TOP-002-2 R3 (proposed to be covered in the future by TOP-003-2, as outlined in Project 2007-03’s Implementation Plan) already requires the Generator Operator to coordinate with its interconnecting Transmission Operator. Further, TOP-001-1 R3 (proposed to be covered in the future in the proposed IRO-001-2 R2 and R3) already requires the Generator Operator to comply with reliability directives issued by the Transmission Operator. These requirements effectively give the Transmission Operator decision-making authority over operation of all generator

Facilities up to the point of interconnection. To require the same thing in TOP-001-1 would be redundant.

***TOP-004-2—Transmission Operations (addressed in the Ad Hoc Report, and the June 16 FERC Order)***

The Ad Hoc Report, and the June 16 FERC Order both address the application of TOP-004-2 R6 to Generator Operators. TOP-004-2 R6 ensures formal policies and procedures are formulated to provide for coordination of activities that may impact reliability. In paragraphs 67 and 82 of the June 16 FERC Order, FERC talks about entities ensuring the development of coordination protection to coordinate switching a generator interconnection Facility in and out of service, since different entities have control over different ends of the line. FERC concludes that for the entities in question, TOP-004-2 R6 must apply.

Requirement R6 and its sub-requirements state: “R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: R6.1. Monitoring and controlling voltage levels and real and reactive power flows, R6.2. Switching transmission elements, R6.3. Planned outages of transmission elements, R6.4. Responding to IROL and SOL violations.”

TOP-001-1 R3 appropriately requires the Generator Operator to comply with reliability directives issued by the Transmission Operator. These requirements give the Transmission Operator the necessary decision-making authority over operation of all generator Facilities, including interconnection Facilities, up to the point of interconnection. Further, TOP-002-2 R3 requires the Generator Owner to coordinate its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. These entities are, in turn, required to coordinate with their respective Transmission Operators (also in TOP-002-2 R3). Each Balancing Authority and Transmission Operator is also then required to coordinate with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator (in TOP-002-2 R4). The coordination with which NERC and FERC are concerned is already addressed by these other requirements.

The Ad Hoc Group had proposed a new requirement, R7, for TOP-004-2 that would read: “The Generator Operator shall operate its Generator Interconnection Facility within its applicable ratings.” The SDT does not agree that a reliability gap exists and cites the following standards to support this conclusion. The purpose statements of FAC-008-3 and FAC-009-1—infer that the reason for establishing a ratings methodology and communicating Facility Ratings to the Reliability Coordinator, Planning Authority, Transmission Planner, and Transmission Operator is “...for use in reliable planning and operation of the Bulk Electric System.” The SDT also notes that the purpose statements of IRO-001-1.1 and TOP-001-1a infer that the Reliability Coordinator and the TOP are given the authority and

are assigned responsibility to take appropriate actions or direct the actions of others to return the transmission system to normal (reliable) conditions.

All appropriate coordination that might be proposed by applying TOP-004-2 to Generator Operators is already addressed in other standards (TOP-001-1 R3, TOP-002-2 R3, FAC-008-3, and FAC-009-1). TOP-004-2 has been proposed for retirement under Project 2007-03—Real-time Transmission Operations, whose standards have been approved by the NERC Board of Trustees. Complementary standards TOP-001-1 R3 and TOP-002-2 R3 have also been proposed for retirement, but their requirements will be covered under proposed IRO-001-3 R2, R3, and R4 and proposed TOP -003-2, approved MOD-001-1a R1 and R2, and approved MOD-030-2 R3 (respectively).

***TOP-006-1/TOP-006-2—Monitoring System Conditions***

The SDT considered modification to TOP-006-1 because R3 ensures technical information is provided to the responsible personnel and R6 ensures correct and accurate data to TOP and BA. However, PRC-001-1 R1 (“Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area”) addresses the necessary Generator Operator requirements with respect to TOP-006-2 R3. The SDT concluded that knowledge of the purpose and limitations of protection system schemes applied in its area (required in PRC-001-1 R1) constitutes knowledge of “the appropriate technical information concerning protective relays” (required in TOP-006-1 R3).

TOP-006-2 R6 states “Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.” FAC-001-1 R2.1.6 already requires the Transmission Owner’s facility connection requirements to address “metering and telecommunications.” Any generator Facility that interconnected with a Transmission Owner would have had to meet that Transmission Owner’s Facility connection and system performance requirements for metering and telecommunications. Thus, there is no reliability gap.

***TOP-008-1—Response to Transmission Limit Violations (addressed in the Ad Hoc Report)***

Only the Ad Hoc Report addressed TOP-008-1, and it proposed a new requirement, R5, to TOP-008-1—Response to Transmission Limit Violations that would read “The Generator Operator shall disconnect the Generator Interconnection Facility when safety is jeopardized or the overload or abnormal voltage or reactive condition persists and generating equipment or the Generator Interconnection Facility is endangered. In doing so, the Generator Operator shall notify its Transmission Operator and Balancing Authority impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.” The SDT sees no reliability benefit to adding this requirement. TOP-001-1 R7 (“Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless...”) and its parts give the Generator Operator authority over its Facilities, which would include the generator interconnection

Facility. If there is an outage, R7.1 requires the Generator Operator to notify and coordinate with its interconnecting Transmission Operator, who, in turn, is required to notify the Reliability Coordinator and other affected Transmission Operators.

As with TOP-004-2, the Project 2007-03 drafting team has proposed deleting all of TOP-008-1's requirements and retiring the standard. The appropriate coordination requirements, currently addressed in TOP-001-1 R7, are addressed in the proposed TOP-001-2 R5 and proposed TOP-003-2 R5.

#### **IV. Conclusion**

The SDT has concluded that the proposed modifications to FAC-001, FAC-003, PRC-004, and PRC-005 Reliability Standards will close the reliability gaps that exist for the vast majority of the sole-purpose interconnection lines owned or operated by generating entities included in the NERC Compliance Registry.

The SDT does, however, acknowledge that some Facilities used solely to connect generators to the transmission system are more complex and therefore require individual assessment. The SDT has concluded that reliability gaps associated with such Facilities should not be addressed simply through application of all standards applicable to Transmission Owners and Transmission Operators, but instead has concluded that an individualized assessment of the impact of such a Facility on neighboring transmission Facilities is warranted. Such assessment should then be used to determine exactly which Reliability Standards and requirements should apply to that Facility and whether additional entity registration is warranted. The SDT concluded that this assessment should, at a minimum, be based upon the output of transmission planning and operating studies used by the Reliability Coordinator, Transmission Operator, and Transmission Planner in complying with applicable Reliability Standards (specifically, IRO, TOP and TPL).

The SDT would like to extend its thanks to all stakeholders who have contributed to this process – either formally or informally – and hopes that NERC and FERC will support moving this project to a successful solution that ensures that generator interconnection Facility responsibility is appropriately assigned under NERC's Reliability Standards.

**Exhibit D**

**Implementation Plan for Reliability Standard submitted for Approval**

# Implementation Plan for FAC-001-1—Facility Connection Requirements

## **Prerequisite Approvals**

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

## **Revision to Sections of Approved Standards and Definitions**

There are no proposed revisions to requirements in other already approved standards. FAC-001-0 – Facility Connection Requirements will be retired at midnight the day before FAC-001-1 becomes effective.

## **Compliance with Standard**

Since this version of the standard imposes no changes to Transmission Owners from those in the FERC-approved version of the standard, the expectation is that Transmission Owners will maintain their current state of compliance. Thus, the standard is effective for Transmission Owners upon approval, as detailed below.

The proposed changes to the FERC-approved version of this standard only address Generator Owner applicability and requirements (add Generator Owner to section 4.2, introduce a new requirement (R2), and modify one existing requirement (now R3)). Therefore, this implementation plan only identifies a compliance timeframe for Generator Owners to which this standard will apply.

## **Effective Date**

There are two effective dates associated with this standard:

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner and Regional Entity become effective upon Board of Trustees' adoption.

In those jurisdictions where regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities. In those jurisdictions where no regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after Board of Trustees' adoption.



# Implementation Plan for FAC-003-3 — Transmission Vegetation Management

## Prerequisite Approvals

There are a number of scenarios that could occur regarding the approval of FAC-003-2 that would affect the implementation of FAC-003-3.

If FAC-003-2 is filed with applicable regulatory authorities and approved before FAC-003-3 is filed with applicable regulatory authorities, then when and if FAC-003-3 is approved by applicable regulatory authorities, the implementation plan and effective dates for Transmission Owners in FAC-003-2 will be transferred into this implementation plan. The “clock” for calculating effective dates for Transmission Owners will still have started at the time specified in FAC-003-2 (based on the approval date of that standard). Generator Owners will be required to comply with the implementation plan as outlined below.

If applicable regulatory authorities elect to approve only FAC-003-3 and not FAC-003-2, the original implementation plan for Transmission Owners as outlined in FAC-003-2 will be transferred into this implementation plan. Generator Owners will be required to comply with the implementation plan as outlined below. The “clocks” for calculating the effective dates for both Transmission Owners and Generator Owners will begin at the same time.

If applicable regulatory authorities approve FAC-003-2 and FAC-003-3 at the same time, the implementation plan and effective dates for Transmission Owners in FAC-003-2 will be transferred into this implementation plan and FAC-003-2 will be immediately retired. Generator Owners will be required to comply with the implementation plan as outlined below. The “clocks” for calculating the effective dates for both Transmission Owners and Generator Owners will begin at the same time.

## Revision to Sections of Approved Standards and Definitions

There are no proposed revisions to requirements in other already approved standards. All requirements and the two revised definitions in the proposed standard FAC-003-2 will be retired at midnight the day before FAC-003-3 becomes effective.

There are two revised definitions in the proposed standard:

### Right-of-Way (ROW)

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either



construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria.

### **Vegetation Inspection**

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

There is one new definition in the proposed standard:

### **Minimum Vegetation Clearance Distance (MVCD)**

The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

The current glossary definitions of Right-of-Way and Vegetation Inspection, or the glossary definitions of Right-of-Way and Vegetation Inspection in FAC-003-2, if that standard has been approved, will be retired at midnight the day before FAC-003-3 (and with it, the above definitions of Right-of-Way and Vegetation Inspection) becomes effective. The above definition of Minimum Vegetation Clearance Distance will be added to the NERC Glossary of Terms upon approval of FAC-003-3, or the above definition of Minimum Vegetation Clearance Distance will replace (and thus force the retirement, at midnight the day before FAC-003-3 is approved) of the same definition in FAC-003-2, if FAC-003-2 has been approved.

### **Compliance with Standard**

As outlined above under "Prerequisite Approvals," the inclusion of Transmission Owners in this implementation plan will depend on the order in which regulatory authorities approve FAC-003-2 and FAC-003-3. Therefore, this implementation plan only identifies a compliance timeframe for Generator Owners to which this standard will apply.

To reach compliance with the standard, a Generator Owner will have to perform a full review of as-built drawings and determine which generation interconnection Facilities require a Transmission Vegetation Management Plan (TVMP) and inspection as specified by NERC Reliability Standard FAC-003-3. In general, Generator Owners do not have staff that are qualified and experienced to create a TVMP, perform Right-of-Way inspections, and perform any required tree trimming). Once a complete inventory is created, the Generator Owner will begin the process of gathering information for the TVMP. In instances where the generation interconnection Facilities are owned by a partnership, a majority or operating partner will need to obtain partnership approval to proceed with procurement of

a TVMP expert, and later a tree trimming crew. Typically, a request for proposal to hire a TVMP consultant is initiated which could take several weeks in order to obtain sufficient bids (and also satisfy Sarbanes Oxley requirements). Once all bids have been received, a contract with a TVMP consultant is signed. At this point, the TVMP consultant and Generator Owner staff will develop the TVMP, which needs to take into account local growth conditions, types of vegetation and other aspects required by FAC-003. Once the TVMP is developed, Generator Owner staff and the TVMP consultant will need to perform a Right-of-Way inspection (as required in FAC-003-3 Requirement 1), usually done using GPS, LIDAR and other tools by experienced and qualified staff.

Once a Right-of-Way inspection is completed and clearances are required, the Generator Owner will need to issue a request for proposal to hire a tree trimming crew that is qualified and experienced to perform required clearance trimming. Once all bids have been received, a contract with a tree trimming crew is signed. When the tree trimming crew is acquired, the crew will need to familiarize themselves with the entity's TVMP and required clearances. The Generator Owner will typically need to schedule any required outages in order for the tree trimming crew to perform the needed clearance trimming. This action would also include the implementation of the work plan as required in FAC-003-3 Requirement 2. During scheduled outages, if required, the tree trimming crew will perform any required clearances and document the activities.

Another typical action is the Generator Owner establishing a system for maintaining TVMP-related activities, including maintenance of inspection and clearance documentation. On an ongoing basis, in addition to performing inspections and clearances as required by the entity's TVMP, the Generator Owner will need to ensure that the training and qualification requirements for the standard are met. The entity will also need to maintain documentation of all FAC-003-3 activities for compliance period of one year to meet compliance with the standard.

Again, due to a typical lack of experience and qualifications required by FAC-003-3, compliance with this standard by a Generator Owner may take as long as two years – in part because many entities will have generator interconnection Facilities in various parts of the country which may require several instances of TVMP and numerous Right-of-Way inspections.

### **Effective Date**

There are two effective dates associated with this implementation plan:

The first effective date allows Generator Owners time to develop documented maintenance strategies or procedures or processes or specifications as outlined in Requirement R3.

In those jurisdictions where regulatory approval is required, Requirement R3 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities

where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

The second effective date allows entities time to comply with Requirements R1, R2, R4, R5, R6, and R7.

In those jurisdictions where regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 become effective on the first day of the first calendar quarter two years following Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.
2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.
3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.
4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.

5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

# Implementation Plan for PRC-004-2.1a— Analysis of Transmission and Generation Protection System Misoperations

## **Prerequisite Approvals**

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

## **Revision to Sections of Approved Standards and Definitions**

There are no proposed revisions to requirements in other already approved standards. PRC-004-2a will be retired when PRC-004-2.1a becomes effective.

## **Compliance with Standard**

The proposed change to Requirement R2 is a clarifying change. While there was no reliability gap in the previous version of the standard, if applied literally, there was the possibility for the misperception that the Generator Owner was only responsible for analyzing its generator Protection System Misoperations, exclusive of its generator interconnection Facility. The errata change to R2 makes clear that generator interconnection Facilities are also part of Generator Owners' responsibility in the context of this standard.

Because the change is merely a clarifying change, no additional time for compliance is needed.

## **Effective Date**

In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements become effective upon Board of Trustees' adoption.

# Implementation Plan for PRC-005-1.1b— Transmission and Generation Protection System Maintenance and Testing

## **Prerequisite Approvals**

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

## **Revision to Sections of Approved Standards and Definitions**

There are no proposed revisions to requirements in other already-approved standards. PRC-005-1b will be retired when PRC-005-1.1b becomes effective.

## **Compliance with Standard**

The proposed changes to Requirement R1 and R2 are clarifying changes. While there was no reliability gap in the previous version of the standard, if applied literally, there was the possibility for the misperception that the Generator Owner was only responsible for analyzing its generator Protection System, exclusive of its generator interconnection Facility Protection System. The minor changes to R1 and R2 make clear that generator interconnection Facilities are also part of Generator Owners' responsibility in the context of this standard.

Because the change is merely a clarifying change, no additional time for compliance is needed.

## **Effective Date**

In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements become effective upon Board of Trustees' adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

## **Exhibit E**

### **Consideration of Comments**

Project 2010-07

Generator Requirements at the Transmission Interface

Related Files

**Status:**

FAC-001-1, FAC-003-3, PRC-004-2.1a, and PRC-005-1.1b and all associated documents were adopted by NERC's Board of Trustees (BOT) in February and May 2012. They are pending regulatory filing.

**Purpose/Industry Need:**

The proposed changes to the requirements and the addition of new requirements will add significant clarity to Generator Owners and Generator Operators regarding their reliability standard obligations at the interface with the interconnected grid.

Draft	Action	Dates	Results	Consideration of Comments
<p><b>FAC-003-x</b>  <a href="#">Clean</a>   <a href="#">Redline to Last Posted</a>   <a href="#">Redline to Last Approved</a></p> <p><b>Implementation Plan</b>  <a href="#">Clean</a>   <a href="#">Redline to Last Posted</a></p> <p><b>FAC-003-3</b>  <a href="#">Clean</a>   <a href="#">Redline to Last Posted</a>   <a href="#">Redline to Last Approved</a></p> <p><b>Implementation Plan</b>  <a href="#">Clean</a>   <a href="#">Redline to Last Posted</a></p> <p><b>Consideration of Comment Report</b>            (FAC-003-3 and FAC-003-x - for reference; from successive ballot that took place March 9 - April 9, 2012)  <a href="#">Clean</a></p> <p><b>PRC-005-1.1b</b>  <a href="#">Clean</a>   <a href="#">Redline to Last Posted</a></p> <p><b>Implementation Plan</b>  <a href="#">Clean</a>   <a href="#">Redline to Last Posted</a></p> <p><b>Consideration of Comment Report</b>            (PRC-005-1.1b for reference; from initial ballot that took place from March 2 -</p>	<p>Recirculation Ballot</p> <p><a href="#">Info&gt;&gt;</a></p> <p><a href="#">Vote&gt;&gt;</a></p>	<p>04/24/12            -            05/03/12            (closed)</p>	<p><a href="#">Summary&gt;&gt;</a></p> <p>Ballot Results:</p> <p><a href="#">FAC-003-3</a>  <a href="#">FAC-003-x</a>  <a href="#">PRC-005-1.1b</a></p>	



<p>April 16, 2012)  <a href="#">Clean</a></p> <p><b>Technical Justification Document</b>  (for reference; updated from the version posted in March 2012)  <a href="#">Clean</a>   <a href="#">Redline</a></p>				
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On January 20, 2012, Exelon submitted a Level 1 Appeal of the process, challenging the results of the recirculation ballots of FAC-003-3 and FAC-003-X that concluded on Dec. 23, 2011. The NERC Vice President of Standards and Training and then the Standards Committee's Executive Committee reviewed the appeal and found for the appellant, determining that the modifications the SDT made to the applicability of FAC-003-3 and FAC-003-x prior to the recirculation ballot were substantive. Consequently the results of the recirculation ballots for FAC-003-3 and FAC-003-x have been declared void. The SDT has made minor modifications to the standards and posted them for a parallel formal comment period and successive ballot.

[Exelon's Level 1 Appeal](#)  
[NERC Vice President of Standards and Training Response](#)

<p><b>FAC-003-x</b>  <a href="#">Clean</a>  <a href="#">Redline to Last Posted</a></p> <p><b>FAC-003-3</b>  <a href="#">Clean</a>   <a href="#">Redline to Last Posted</a></p>	<p>Successive Ballot</p> <p><a href="#">Info&gt;&gt;</a></p> <p><a href="#">Vote&gt;&gt;</a></p>	<p>3/30/12  -  04/09/12  (closed)</p>	<p><a href="#">Info&gt;&gt;</a></p> <p>Full Records:  <a href="#">FAC-003-x</a>  <a href="#">FAC-003-3</a></p>	
<p><b>Implementation Plans</b>  <b>FAC-003-x</b>  <a href="#">Clean</a></p> <p><b>FAC-003-3</b>  <a href="#">Clean</a></p> <p><b>Supporting Materials:</b>  <a href="#">Unofficial Comment Form (Word)</a></p> <p><a href="#">Standards Committee Executive Committee 2/23/12 meeting minutes (directing that Recirculation Ballot Results be voided and work remanded to the SDT)</a></p> <p><a href="#">Letter from SC Chairman to Project 2010-07 SDT Chair</a></p> <p><b>Technical Justification Document</b>  (for reference; updated from the version posted in December 2011)  <a href="#">Clean</a>   <a href="#">Redline</a></p>	<p>Formal Comment Period</p> <p><a href="#">Submit Comments&gt;&gt;</a></p>	<p>03/09/12  -  04/09/12  (closed)</p>	<p><a href="#">Comments Received&gt;&gt;</a></p>	<p><a href="#">Consideration of Comments(6)</a></p>

<p><b>Consideration of Comment Report</b>  (for reference; updated from successive ballot that took place October 5- November 18, 2011)  <a href="#">Clean</a>   <a href="#">Redline</a></p>				
<p><b>PRC-005-1.1a</b>  <a href="#">Clean</a>   <a href="#">Redline to Last Approved</a></p> <p><b>Implementation Plan</b>  <a href="#">Clean</a></p> <p><b>Supporting Materials</b>  Unofficial Comment Form (Word)</p>	<p>Initial Ballot</p> <p>Updated  <a href="#">Info&gt;&gt;</a>  <a href="#">Info&gt;&gt;</a></p> <p><a href="#">Vote&gt;&gt;</a></p>	<p>04/06/12  -  04/16/12  (closed)</p>	<p><a href="#">Info&gt;&gt;</a></p> <p><a href="#">Full Record&gt;&gt;</a></p>	
	<p>Formal Comment Period</p> <p><a href="#">Submit Comments&gt;&gt;</a></p>	<p>03/02/12  -  04/16/12  (closed)</p>	<p><a href="#">Comments Received&gt;&gt;</a></p>	<p><a href="#">Consideration of Comments(5)</a></p>
	<p><a href="#">Join Ballot Pool&gt;&gt;</a></p>	<p>03/02/12  -  03/31/12  (closed)</p>		
<p><b>FAC-001-1</b>  <a href="#">Clean</a>   <a href="#">Redline to Last Approved Implementation Plan</a></p> <p><b>PRC-004-2.1a</b>  <a href="#">Clean</a>   <a href="#">Redline to Last Approved Implementation Plan</a></p> <p><b>Supporting Materials:</b>  Technical Justification  <a href="#">Clean</a>   <a href="#">Redline</a></p> <p><a href="#">Technical Justification for FAC-001-1</a></p> <p>Sole-use Generator Interconnection Facility: <a href="#">Diagram 1</a></p> <p>Sole-use Generator Interconnection Facility: <a href="#">Diagram 2</a></p> <p><a href="#">VRF and VSL Justification</a></p>				

<p>FAC-001-1 VRFs and VSLs  <a href="#">Clean</a>   <a href="#">Redline to last approved</a></p> <p><b>Supporting Materials:</b></p> <p><a href="#">VRF and VSL Justification</a></p> <p><a href="#">FAC-001-1 Implementation Plan</a></p>	<p>Non-binding  Poll</p> <p><a href="#">Info&gt;&gt;</a></p> <p><a href="#">Vote&gt;&gt;</a></p>	<p>01/04/12  -  01/13/12  (closed)</p>	<p><a href="#">Non-Binding  Poll  Results&gt;&gt;</a></p>	
<p><b>FAC-001-1</b>  <a href="#">Clean</a>   <a href="#">Redline to Last Posted</a>   <a href="#">Redline to Last Approved</a></p> <p><b>FAC-003-X</b>  <a href="#">Clean</a>   <a href="#">Redline to Last Posted</a></p> <p><b>FAC-003-3</b>  <a href="#">Clean</a>   <a href="#">Redline to Last Posted</a></p> <p><b>PRC-004-2.1</b>  <a href="#">Clean</a>   <a href="#">Redline to Last Posted</a>   <a href="#">Redline to Last Approved</a></p> <p><b>Implementation Plans</b></p> <p>FAC-001-1  <a href="#">Clean</a></p> <p>FAC-003-3  <a href="#">Clean</a></p> <p>FAC-003-X  <a href="#">Clean</a></p> <p>PRC-004-2.1  <a href="#">Clean</a></p> <p><b>Supporting Materials:</b></p> <p><a href="#">Technical Justification</a>  <a href="#">Clean</a>   <a href="#">Redline</a></p> <p><a href="#">Technical Justification for FAC-001-1</a></p> <p>Sole-use generator interconnection  Facility: <a href="#">Diagram 1</a></p> <p>Sole-use generator interconnection  Facility: <a href="#">Diagram 2</a></p>	<p>Recirculation  Ballots</p> <p><a href="#">Info&gt;&gt;</a></p> <p><a href="#">Vote&gt;&gt;</a></p>	<p>12/14/11  -  12/23/11  (closed)</p>	<p><a href="#">Summary&gt;&gt;</a></p> <p>Full Record  Reports:</p> <p><a href="#">FAC-001-1</a>  <a href="#">FAC-003-X</a>  <a href="#">FAC-003-3</a>  <a href="#">PRC-004-2.1</a></p>	<p>Full Record  Reports  (<b>NOTE</b> that the results of the recirculation ballots of FAC-003-3 and FAC-003-x were voided as a result of an appeal, and a successive ballot of the two standards was conducted. The appeal and response are posted on this project page.)</p> <p><a href="#">FAC-001-1</a>  <a href="#">FAC-003-x</a>  <a href="#">FAC-003-3</a>  <a href="#">PRC-004-2.1</a></p>

<p><b>FAC-001-1</b> Clean   <a href="#">Redline to Last Posted</a>   <a href="#">Redline to Last Approved</a></p> <p><b>FAC-003-X</b> Clean   <a href="#">Redline to Last Posted</a>   <a href="#">Redline to Last Approved</a></p> <p><b>FAC-003-3</b> Clean   <a href="#">Redline to Last Posted</a></p> <p><b>FAC-003-3 with revised VSLs based on FAC-003-2 adopted by NERC BOT (added 11/09/11)</b> Clean   <a href="#">Redline to version of FAC-003-3 posted 10/05/11</a></p> <p><b>PRC-004-2.1</b> Clean   <a href="#">Redline to Last Approved</a></p> <p><b>Implementation Plans</b> FAC-001-1 <a href="#">Clean</a>   <a href="#">Redline</a></p> <p>FAC-003-3 <a href="#">Clean</a>   <a href="#">Redline</a></p> <p>FAC-003-X <a href="#">Clean</a>   <a href="#">Redline</a></p> <p>PRC-004-2 Clean</p> <p><b>Supporting Materials:</b> <a href="#">Technical Justification</a></p> <p><a href="#">Technical Justification for FAC-001-1</a></p> <p><a href="#">Unofficial Comment Form (Word)</a></p>	<p>Join Ballot Pool</p> <p><a href="#">Info&gt;&gt;</a></p> <p><a href="#">Join&gt;&gt;</a></p> <p>Initial Ballot</p> <p>Updated</p> <p><a href="#">Info&gt;&gt;</a></p> <p><a href="#">Info&gt;&gt;</a></p> <p><a href="#">Vote&gt;&gt;</a></p> <p>Comment Period</p> <p><a href="#">Info&gt;&gt;</a></p> <p><a href="#">Submit Comments&gt;&gt;</a></p>	<p>10/05/11 - 11/04/11 (closed)</p> <p>11/09/11 - 11/18/11 (closed)</p> <p>10/05/11 - 11/18/11 (closed)</p>	<p><a href="#">Summary&gt;&gt;</a></p> <p>Full Record Report: <a href="#">FAC-001-1</a> <a href="#">FAC-003-X</a> <a href="#">FAC-003-3</a> <a href="#">PRC-004-2.1</a></p> <p><a href="#">Comments Received&gt;&gt;</a></p>	<p><a href="#">Consideration of Comments(4)</a></p>
<p><b>FAC-001-1</b> Clean   <a href="#">Redline to last approved</a></p> <p><a href="#">Implementation Plan</a></p>	<p>Formal Comment Period</p> <p><a href="#">Info&gt;&gt;</a></p>	<p>06/17/11 - 07/17/11 (closed)</p>		

<p><b>FAC-003-3</b></p> <p>Clean   <a href="#">Redline to last approved</a></p> <p><a href="#">Implementation Plan</a></p> <p><b>FAC-003-X</b></p> <p>Clean   <a href="#">Redline to Project 2007-07 last balloted</a></p> <p><a href="#">Implementation Plan</a></p> <p><b>Supporting Materials</b></p> <p><a href="#">Background Resource (White Paper)</a></p> <p><a href="#">Comment Form (Word)</a></p>	<p><a href="#">Submit Comments&gt;&gt;</a></p>		<p><a href="#">Comments Received&gt;&gt;</a></p>	<p><a href="#">Consideration of Comments(3)</a></p>
<p><a href="#">White Paper</a></p> <p><b>Supporting Materials</b></p> <p><a href="#">Attachment 1</a>   <a href="#">Attachment 2</a></p>	<p>Informal Comment Period</p> <p><a href="#">Info&gt;&gt;</a></p> <p><a href="#">Submit Comments&gt;&gt;</a></p>	<p>03/04/11 - 04/04/11 (closed)</p>	<p><a href="#">Comments Received&gt;&gt;</a></p>	<p><a href="#">Summary Consideration of Comments(2)</a></p>
<p>SAR</p> <p>Clean   <a href="#">Redline</a></p>				
<p>Generator Requirements at the Transmission Interface (GOTO)</p> <p>SAR</p> <p><a href="#">Redline Standard Changes</a></p> <p><b>Supporting Materials</b></p> <p><a href="#">GOTO Final Report</a></p> <p><a href="#">Comment Form (Word)</a></p>	<p>Comment Period</p> <p><a href="#">Submit Comments&gt;&gt;</a></p> <p><a href="#">Info&gt;&gt;</a></p>	<p>02/12/10 - 03/15/10 (closed)</p>	<p><a href="#">Comments Received&gt;&gt;</a></p>	<p><a href="#">Consideration of comments(1)</a></p>
<p>Drafting Team Nominations Open</p> <p><a href="#">Nomination Form (Word)</a></p>	<p><a href="#">Submit Nomination&gt;&gt;</a></p> <p><a href="#">Info&gt;&gt;</a></p>	<p>02/12/10 - 03/01/10 (closed)</p>		

## Consideration of Comments on Generator Requirements at the Transmission Interface — Project 2010-07

The GOTO Drafting Team thanks all commenters who submitted comments on the proposed SAR and modifications to several reliability standards and NERC Glossary terms associated with the recommendations of the Generator Requirements at the Transmission Interface Ad Hoc Group, embodied in Project 2010-07. These standards were posted for a 30-day public comment period from February 12, 2010 through March 15, 2010. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 41 sets of comments, including comments from more than 80 different people from over 60 companies representing 7 of the 10 Industry Segments as shown in the table on the following pages.

In this report, comments have been organized by question number. All comments may be reviewed in their original format on the following web page:

[http://www.nerc.com/filez/standards/Project2010-07\\_GOTO\\_Project.html](http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html)

Based on stakeholder comments, along with discussions with FERC and NERC staff, the SAR drafting team (SAR DT) made the following modifications to the SAR:

- Gave the Standard Drafting Team (SDT) the flexibility to include additional standards not originally identified in the Ad Hoc Task Force Report
- With respect to new terms and modifications of definitions of terms, the SAR DT made it clearer that the SDT can adopt proposals as indicated in the Ad Hoc Task Force Report or modify them to address stakeholder concerns
- Gave the SDT the option of merging the Ad Hoc Task Force's proposed changes into one new standard or an existing standard(s) if deemed appropriate
- Language changes for clarity

Some commenters indicated that the SAR as written was too broad, but the SDT believes that giving the SDT as many options as possible is advantageous. The SDT will be the team to ultimately determine which standards should be modified.

Many commenters made specific recommendations for modifications to standards. The SAR DT has compiled those comments for use during the next phase of this project, standard drafting. In particular, the comments on Question 7 and its subcomponents were intended to provide input for the SDT in the development of its implementation plan to accompany the project as it moves forward. The most frequently cited challenges – training, agreements, and technical details – will be considered by the SDT.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 315-439-1390 or at [herb.schrayshuen@nerc.net](mailto:herb.schrayshuen@nerc.net). In addition, there is a NERC Reliability Standards Appeals Process.<sup>1</sup>

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<sup>1</sup> The appeals process is in the Reliability Standards Development Procedures:  
<http://www.nerc.com/standards/newstandardsprocess.html>.

## Index to Questions, Comments, and Responses

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6. Do you believe there are any other Transmission Owner or Transmission Operator standards or requirements that should be applicable to the Generator Owner or Generator Operator other than those identified?.....	51
7. The next posting of the proposed revisions to these standards will include conforming changes to the measures and compliance elements, and will include an implementation plan. Please identify how much time you feel an entity will need to become fully compliant with the following new/revised requirements:.....	54
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**Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07**

The Industry Segments are:

- 1 — Transmission Owners
- 2 — RTOs, ISOs
- 3 — Load-serving Entities
- 4 — Transmission-dependent Utilities
- 5 — Electric Generators
- 6 — Electricity Brokers, Aggregators, and Marketers
- 7 — Large Electricity End Users
- 8 — Small Electricity End Users
- 9 — Federal, State, Provincial Regulatory or other Government Entities
- 10 — Regional Reliability Organizations, Regional Entities

		Commenter	Organization	Industry Segment										
				1	2	3	4	5	6	7	8	9	10	
1.	Group	Philip R. Kleckley	SERC Planning Standards Subcommittee	X		X		X						
		<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>			<b>Segment Selection</b>							
1.	John Sullivan	Ameren Services Company	SERC				1							
2.	Charles Long	Entergy	SERC				1							
3.	James Manning	North Carolina Electric Membership Corporation	SERC				3							
4.	Pat Huntley	SERC Reliability Corporation	SERC				10							
5.	Bob Jones	Southern Company Services, Inc. - Transmission	SERC				1							
2.	Group	Guy Zito	Northeast Power Coordinating Council											X
		<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>			<b>Segment Selection</b>							
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC				10							
2.	Gregory Campoli	New York Independent System Operator	NPCC				2							
3.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC				2							
4.	Kurtis Chong	Independent Electricity System Operator	NPCC				2							
5.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC				1							
6.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC				1							



Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07

	Commenter	Organization	Industry Segment												
			1	2	3	4	5	6	7	8	9	10			
7.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC								10				
8.	Ben Eng	New York Power Authority	NPCC								4				
9.	Brian Evans-Mongeon	Utility Services	NPCC								8				
10.	Mike Garton	Dominion Resources Services, Inc.	NPCC								5				
11.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC								5				
12.	Kathleen Goodman	ISO - New England	NPCC								2				
13.	David Kiguel	Hydro One Networks Inc.	NPCC								1				
14.	Michael R. Lombardi	Northeast Utilities	NPCC								1				
15.	Randy MacDonald	New Brunswick System Operator	NPCC								2				
16.	Greg Mason	Dynegy Generation	NPCC								5				
17.	Bruce Metruck	New York Power Authority	NPCC								6				
18.	Chris Orzel	FPL Energy/NextEra Energy	NPCC								5				
19.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC								10				
20.	Robert Pellegrini	The United Illuminating Company	NPCC								1				
21.	Saurabh Saksena	National Grid	NPCC								1				
22.	Michael Schiavone	National Grid	NPCC								1				
23.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC								3				
3.	Group	Rick Terrill	Luminant					X							
4.	Group	Jalal Babik	Electric Market Policy	X		X		X	X						
<b>Additional Member</b>		<b>Additional Organization</b>		<b>Region</b>				<b>Segment Selection</b>							
1.	Louis Slade		SERC								5				
2.	Mike Garton		NPCC								6				
5.	Group	Ben Li	ISO RTO Council Standards Review Committee		X										
<b>Additional Member</b>		<b>Additional Organization</b>		<b>Region</b>				<b>Segment Selection</b>							
1.	Patrick Brown		PJM								2				
2.	Jame Castle		NYISO								2				

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		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
3.		Lourdes Estrada-Salinero	CAISO	WECC						2			
4.		Matt Goldberg	ISO NE	NPCC						2			
5.		Steve Myers	ERCOT	ERCOT						2			
6.		Bill Phillips	MISO	RFC						2			
7.		Mark Thompson	AESO	WECC						2			
8.		Charles Yeung	SPP	SPP						2			
6.	Group	Jason L. Marshall	Midwest ISO Standards Collaborators		X								
Additional Member		Additional Organization		Region					Segment Selection				
1.		Steve Rose	CWLP	SERC					1				
2.		Jim Cyrulewski	JDRJC Associates, LLC	RFC					8				
3.		Joe Knight	Great River Energy	MRO					1, 3, 5, 6				
4.		Barb Kedrowski	We Energies	RFC					3, 4, 5				
5.		Sam Ciccone	First Energy	RFC					1, 3, 4, 5, 6				
6.		Doug Hohlbaugh	First Energy	RFC					1, 3, 4, 5, 6				
7.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				
Additional Member		Additional Organization		Region					Segment Selection				
1.			City of Vero Beach	FRCC					3				
2.			City of New Smyrna Beach	FRCC					3				
3.			Kissimmee Utility Authority	FRCC					3				
4.			Lakeland Electric	FRCC					3				
5.			City of Clewiston	FRCC					3				
6.			Beaches Energy Services	FRCC					1				
7.			Fort Pierce Utility Authority	FRCC					4				
8.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				
Additional Member		Additional Organization		Region					Segment Selection				
1.		Jim Burns	BPA, Transmission Technical Operations	WECC					1				

Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
9.	Group	Richard Kafka	Pepco Holdings, Inc - Affiliates	X		X		X	X				
		<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>						<b>Segment Selection</b>			
		1. Kara Dundas	Conectiv Energy Supply, Inc	RFC						5			
		2. Don Bridge	Conectiv Energy Supply, Inc	RFC						5			
		3. James Newton	Pepco Energy Services	RFC						5			
10.	Group	Mary Jo Cooper	First Wind					X					
		<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>						<b>Segment Selection</b>			
		1. First Wind O&M, LLC		NPCC						5			
		2. Canandaigua Power Partners, LLC		NPCC						5			
		3. Canandiagu Power Partners II, LLC		NPCC						5			
		4. Milford Wind Coordin Phase I, LLC		WECC						5			
		5. Stetson Wind II, LLC		NPCC						5			
		6. Evergreen Wind Power V, LLC		NPCC						5			
11.	Group	Kenneth D. Brown	PSEG Companies	X		X		X	X				
		<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>						<b>Segment Selection</b>			
		1. Jim Hebson	PSEG ER&T	NPCC						6			
		2. Dave Murray	PSEG Fossil	ERCOT						5			
		3. Jim Hubertus	PSE&G	RFC						1, 3			
12.	Group	Michael Gammon	Kansas City Power & Light	X		X		X	X				
		<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>						<b>Segment Selection</b>			
		1. Jim Useldinger	KCPL	SPP						1, 3, 5, 6			
		2. Jennifer Flandermeyer	KCPL	SPP						1, 3, 5, 6			
		3. Nick McCarty	KCPL	SPP						1, 3, 5, 6			
		4. Melinda Mangold	KCPL	SPP						1, 3, 5, 6			
		5. Dennis Greashaber	KCPL	SPP						1, 3, 5, 6			
		6. Jerry Hatfield	KCPL	SPP						1, 3, 5, 6			

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		Commenter	Organization	Industry Segment										
				1	2	3	4	5	6	7	8	9	10	
7.	Tom Saitta		KCPL	SPP						1, 3, 5, 6				
8.	Harold Wyble		KCPL	SPP						1, 3, 5, 6				
13.	Individual	Jack Cashin	Energy Standards Working Group											
14.	Individual	Brent Ingebrigtsen	E.ON U.S.	X		X		X	X					
15.	Individual	Silvia Parada-Mitchell	Transmission Owner/Generation Owner	X		X		X	X					
16.	Individual	Larry Rodriguez	Entegra Power Group LLC					X	X					
17.	Individual	Ken Parker	Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners		X									
18.	Individual	Jack Stamper	Public Utility District #1 of Clark County	X										
19.	Individual	Daniel E. Kujala	Detroit Edison Company			X		X						
20.	Individual	Mark Bennett	Competitive Power Ventures, Inc.					X						
21.	Individual	Sam Dwyer	AmerenUE, Power Operations Services					X						
22.	Individual	Amir Hammad	Constellation Power Source Generation Inc.					X						
23.	Individual	Alisha Anker	Prairie Power, Inc.			X								
24.	Individual	Michelle D'Antuono	Ingleside Cogeneration, LP					X						
25.	Individual	Katy Mirr	Sempra Generation					X						
26.	Individual	Robert Ellis	Mesquite Power	X				X						
27.	Individual	Jon Kapitz	Xcel Energy	X		X		X	X					

**Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07**

		Commenter	Organization	Industry Segment										
				1	2	3	4	5	6	7	8	9	10	
28.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X					
29.	Individual	James Sharpe	South Carolina Electric and Gas	X		X		X	X					
30.	Individual	Scott Helyer	Tenaska, Inc.					X						
31.	Individual	Kevin Gillespie	El Dorado Energy LLC					X						
32.	Individual	Patti Metro	National Rural Electric Cooperative Association (NRECA)			X	X							
33.	Individual	Greg Rowland	Duke Energy	X		X		X	X					
34.	Individual	James H. Sorrels, Jr.	American Electric Power	X		X		X	X					
35.	Individual	James Manning, Bob Beadle, Doug White, and Richard McCall	North Carolina Electric Membership Corporation			X	X	X						
36.	Individual	Dan Rochester	Independent Electricity System Operator		X									
37.	Individual	Jason Shaver	American Transmission Company	X										
38.	Individual	Laura Zotter	ERCOT ISO		X									
39.	Individual	Darcy O'Connell	California ISO											X
40.	Individual	Alice Murdock	Xcel Energy	X		X		X	X					
41.	Individual	Marcus Lotto	Southern California Edison co.	X		X		X	X					

1. Do you agree that there is a reliability-related need for the proposed standards action?

**Summary Consideration:** The overwhelming majority of stakeholder comments affirmed the need for this proposed standard action.

Organization	Yes or No	Question 1 Comment
E.ON U.S.	No	E.ON U.S. has already determined a Division of Responsibilities between the GO/TO and therefore does not see the need for auditable reliability standards to be added between the GO/TO.
<p><b>Response:</b> The SAR DT thanks you for your comment. Based on a review of the full body of industry comments, we believe that there is a reliability need for this SAR.</p>		
Luminant	No	In general, Luminant agrees there is a need to address generation facilities with extended connections to the transmission system. However, Luminant does not agree there is a reliability need for the proposed standards action as it relates to generators connected in close proximity to the grid where the connection typically consists of a bus or short wires connection from the high side of a generator step up transformer to the generator breaker.
<p><b>Response:</b> The SAR DT thanks you for your comment. Based on a review of the full body of industry comments, we believe that there is a reliability need for this SAR.</p>		
Kansas City Power & Light	No	There is a need to bring clarity to the Reliability Standards regarding the delineation of what the Generator Owner and Generator Operator is responsible for and for definitions distinguishing between Generator Operators at Power Plants and “Generator Operator” as the “Power System Operator” directing a fleet of generators in a balancing area. I do not believe reliability of the interconnected grid has suffered as a result of the shortcomings of the Reliability Standards in this regard as the electric industry has continued to operate in a responsible manner.
<p><b>Response:</b> The SAR DT thanks you for your comment. Based on a review of the full body of industry comments, we believe that there is a reliability need for this SAR. And while we respect your concern about the definition of Generator Operator versus Power System Operator, we maintain that it is outside the scope of this SAR.</p>		
Detroit Edison Company	No	Vegetation Inspection change to include any BES component Transmission Line or Generator Interconnection Facility Right-of-Way or any other BES component to document vegetation conditions.
<p><b>Response:</b> Thank you for your comment. Based on the SAR DT’s interpretation of this comment, we believe it is outside the scope of the SAR.</p>		

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Organization	Yes or No	Question 1 Comment
AmerenUE, Power Operations Services	Yes	
American Electric Power	Yes	
American Transmission Company	Yes	
Bonneville Power Administration	Yes	
California ISO	Yes	
Duke Energy	Yes	
El Dorado Energy LLC	Yes	
Electric Market Policy	Yes	
Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners	Yes	
ERCOT ISO	Yes	
First Wind	Yes	

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Organization	Yes or No	Question 1 Comment
Florida Municipal Power Agency	Yes	
Independent Electricity System Operator	Yes	
ISO RTO Council Standards Review Committee	Yes	
Mesquite Power	Yes	
Midwest ISO Standards Collaborators	Yes	
National Rural Electric Cooperative Association (NRECA)	Yes	
North Carolina Electric Membership Corporation	Yes	
Prairie Power, Inc.	Yes	
PSEG Companies	Yes	
Public Utility District #1 of Clark	Yes	



Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07

Organization	Yes or No	Question 1 Comment
County		
Sempra Generation	Yes	
SERC Planning Standards Subcommittee	Yes	
South Carolina Electric and Gas	Yes	
Southern California Edison co.	Yes	
Xcel Energy	Yes	
Xcel Energy	Yes	
Entegra Power Group LLC	Yes	But, that action should be reasonable, provide specific detail, and be kept simple so the reliability-related objectives are effectively understood by those operators of the GI Facilities.
<b>Response:</b> The SAR DT thanks you for your comment.		
Energy Standards Working Group	Yes	EPSA members, through active participation in many NERC activities including the team that prepared the report and the attached SAR, are strong advocates of mandatory standards to protect reliability of the Grid. We also strongly agree that there is a need for greater clarity of the responsibilities of Generator Owner/Operators and Transmission Owner/Operators at the Generator Interconnection Interface and thus concur with the direction of this SAR that this should be achieved without the need for Generator Owner/Operators to be included in the registry as Transmission Owner/Operators.
<b>Response:</b> The SAR DT thanks you for your comment.		
Competitive Power	Yes	In fact, the technical analysis in the Ad Hoc Group's Report provides a valuable and useful understanding of the specific nature and extent of reliability issues associated with generator interconnection facilities. Up to now, the need for generator

**Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07**

Organization	Yes or No	Question 1 Comment
Ventures, Inc.		TO/TOP registrations has not been supported by a clear and technically sound rationale. The Report's conclusion, based upon its comprehensive and thorough review, that there is no need for generators to be registered as TO/TOPs to address the specific reliability issues is especially significant.
<b>Response:</b> The SAR DT thanks you for your comment.		
Ingleside Cogeneration, LP	Yes	Ingleside Cogeneration, LP believes that the effort by the Ad Hoc Group for Generator Requirements at the Transmission Interface has generally succeeded in developing criteria clarifying the ownership and operational responsibilities of registered generation and transmission entities at their point of interface. This is an important body of work which needs to result in an end to the forced registration of Generator Owners/Operators (GO/GOP) as Transmission Owner/Operators (TO/TOP) by Regional Entities.
<b>Response:</b> The SAR DT thanks you for your comment.		
Pepco Holdings, Inc - Affiliates	Yes	It is difficult to say if there is a “reliability-related need”. Most GOs operate and maintain their Generator Interconnection Facility in the same manner as the rest of their generation facilities. It is beneficial to differentiate between the “Generation Interconnection Facility” and the “Transmission” system so that GOs do not have to be registered as TOs.
<b>Response:</b> The SAR DT thanks you for your comment.		
Tenaska, Inc.	Yes	Tenaska actively participates in many NERC activities, including the team that prepared the report and the attached SAR/Draft Standards, and strongly advocates the need for reliability of the system. We also strongly agree that there is a need for greater clarity of the responsibilities of Generator Owner/Operators and Transmission Owner/Operators at the Generator Interconnection Interface and thus concur with the direction of this SAR that this should be achieved without the need for Generator Owner/Operators to be included in the registry as Transmission Owner/Operators.
<b>Response:</b> The SAR DT thanks you for your comment.		
Manitoba Hydro	Yes	With the implementation of the new Glossary Terms, this will clarify the dividing point between GO and TO.
<b>Response:</b> The SAR DT thanks you for your comment.		
Constellation Power Source	Yes	Yes - Defining the compliance responsibility to align more accurately with operational reality is important in managing reliability. However, the SDT must also consider those entities that enter into a Joint Registration Organization (“JRO”) for certain GOP reliability standards. This registration exception applies to market entities, where there has been a JRO created

**Consideration of Comments on Generator Requirements at the Transmission Interface — Project 2010-07**

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Organization	Yes or No	Question 1 Comment
Generation Inc.		that delineates specific joint responsibilities, with respect to the GOP reliability standards. It is incumbent on both parties to comply with their agreed upon respective responsibility.
<b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT for their consideration.		

2. Do you agree with the scope of the proposed standards action?

**Summary Consideration:** While there were a number of responses that indicated the SAR was too broad, an in-depth review of the comments indicated that most of the concerns could be addressed by modifications to the proposed standards changes included in the Ad Hoc Report. As a result, many of these comments will be referred to the SDT for their consideration, including final resolution of which standards need to be modified. Based on discussions with FERC and NERC staffs regarding previous Commission actions and NERC compliance filings, the SAR DT also elected to give the SDT the flexibility to include additional standards (now listed in the modified SAR) not identified in the Ad Hoc Report.

Organization	Yes or No	Question 2 Comment
American Electric Power	No	
Luminant	No	Luminant believes the scope of the standards action significantly exceeds the reliability need. The scope should only extend to Generation Interconnection Facilities of greater than one-half (½) mile in length from the property boundary of the generation plant. This standards action should only be applied where there is a demonstrated reliability benefit. For the bulk of the Generator Owners, the proposal creates excessive documentation and paperwork, and increases compliance risk with no reliability benefit to the Bulk Electric System (BES).
<p><b>Response:</b> The SAR DT thanks you for your comment. Based on a review of the full body of industry comments, we believe that the standards actions proposed in this SAR are appropriate. Specific modifications will be determined by the SDT.</p>		
California ISO	No	Adding language in several standards actually creates confusion rather than provide clarity. For example, EOP-003-1 (Load Shedding Plans) applies in situations when there is insufficient generation or transmission, requiring load shedding to avoid risk of uncontrolled failure of the interconnection. This function is generally accomplished through under frequency relay settings which will drop a pre-determined amount of load to maintain generation/load balance. Involving the Generator Operator to comply with this standard is unnecessary and may even complicate matters because the BA and the TOP will now have to coordinate with GOPs. Other similar examples are EOP-001-0, EOP-004-1, and TOP-001-1 where adding “Generator Interconnection Facility” does not add clarity but is rather redundant, and may create interpretation issues.
<p><b>Response:</b> The SAR DT thanks you for your comment. Based on a review of the full body of industry comments, we believe that the standards actions proposed in this SAR are appropriate. Specific modifications will be determined by the SDT.</p>		
Public Utility District #1 of Clark	No	Clark Public Utilities believes the scope of the proposed standards actions is too broad.

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Organization	Yes or No	Question 2 Comment
County		
<p><b>Response:</b> The SAR DT thanks you for your comment. Based on a review of the full body of industry comments, we believe that the standards actions proposed in this SAR are appropriate.</p>		
E.ON U.S.	No	E.ON U.S. has already determined a Division of Responsibilities between the GO/TO and therefore does not see the need for auditable reliability standards to be added between the GO/TO.
<p><b>Response:</b> The SAR DT thanks you for your comment. Based on a review of the full body of industry comments, we believe that the standards actions proposed in this SAR are appropriate.</p>		
Florida Municipal Power Agency	No	<p>FAC-003 should not be applicable to Generator Owners / Operators. The intent of all of the standards is to avoid an Adverse Reliability Impact, or as the FPA Section 215(a)(4) defines “reliable operations” as: “operating the elements of the bulk-power system within equipment and electric system thermal, voltage and stability limits so that instability, uncontrolled separation, or cascading failures of such systems will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.” Radial Facilities serving only generating plants when tripped will not threaten an Adverse Reliability Impact or we would be hard pressed to run that generation in the first place.FMPA believes the intent of the standard is to prevent a cascading event where, if a line trips, another line loads heavily increasing the sag of that line, which may sag into un-cleared vegetation, causing the second line to trip, which may in turn cause heavily loading on a third line, etc. If a line trips in the transmission network, radial Facilities from generating plants will not have their loading changed much at all (since they are radial) and will not participate in this sort of “thermal” cascading event. Hence, there is no cause to regulate vegetation management of radial Facilities to generating plants since the system is always planned and operated to that potential contingency anyway and there is no danger of an Adverse Reliability Impact. Regulating vegetation management on radial Facilities is beyond the scope of the Federal Power Act Section 215.Generator Owners / Operators are still incited to perform adequate vegetation management without the need for regulation because any outage of the plant results in lost opportunity costs to the plant.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Based on a review of the full body of industry comments, we believe that the standards actions proposed in this SAR are appropriate. Specific modifications will be determined by the SDT.</p>		
Ingleside Cogeneration, LP	No	<p>No. Ingleside Cogeneration, LP believes there is a secondary, but equally important issue which we believe has not been fully addressed in the proposed SAR. There can be components of the Generator Interconnection Facility located on the Generator Owner’s property, but are maintained by the Transmission Owner. An excellent example is the relays protecting the interconnected transmission line. Although these are usually purchased by the Generator Owner and are financially carried on their books, in some cases the Transmission Owner performs the associated maintenance and testing. This arrangement can</p>

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Organization	Yes or No	Question 2 Comment
		<p>make sense as the relays are protecting a transmission system and must properly interact with relays on the other side of the transmission line through associated communications systems. This kind of arrangement can lead to a variety of interpretations by auditors even when presented with an Interconnection Agreement specifying the ownership/maintenance arrangement. We believe that if the responsibility to a requirement is clearly delineated in a formal document, the associated collection and presentation of evidence of compliance is part of that responsibility - in this case the TO owning maintenance and testing of protective relays financially owned by the GO. The Exclusion statement under Section III.c.4 of the Statement of Compliance Registry Criteria allows for compliance responsibility to be transferred to another entity provided it registers as the appropriate entity. In addition, we recognize that Sections 501 and 507 of the NERC Rules of Procedure allows distribution of responsibility among two or more entities through a Joint Registration - although that process is designed for tightly connected organizations such as joint ventures or cooperatives.</p> <p>We recommend these all-or-nothing approaches be modified in the exclusion as suggested below:</p> <p style="padding-left: 40px;">A generator owner/operator will not be registered based on these criteria if responsibilities for compliance with approved NERC reliability standards or associated requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, such as a load-serving entity, G&amp;T cooperative or joint action agency as described in Sections 501 and 507 of the NERC Rules of Procedure. "Responsibility for individual requirements applicable to the Generator Interconnection Facility including reporting can be transferred by written agreement without a change to an entity's registration."</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. It is outside the scope of both the SAR DT and the SDT to propose changes to the NERC Rules of Procedure.</p>		
ISO RTO Council Standards Review Committee	No	Please see our comments under Q8.
<p><b>Response:</b> The SAR DT thanks you for your comment. Based on a review of the full body of industry comments, we believe that the standards actions proposed in this SAR are appropriate. Specific modifications will be determined by the SDT.</p>		
Constellation Power Source Generation Inc.	No	Please see the comments for Question #4: Constellation agrees with the proposed new requirements in principal. However, further clarity is needed in the requirements so that there isn't any added confusion. Either an implementation plan or a "frequently asked questions" document would be recommended.
<p><b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT.</p>		

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Organization	Yes or No	Question 2 Comment
Prairie Power, Inc.	No	PPI believes the group has extended the scope too broadly from its initial intent as described in comments below.
<p><b>Response:</b> The SAR DT thanks you for your comment. Based on a review of the full body of industry comments, we believe that the standards actions proposed in this SAR are appropriate. Specific modifications will be determined by the SDT.</p>		
AmerenUE, Power Operations Services	No	While we agree with the overall scope of the proposed actions, there appears to be one missing critical element. What requirement will ensure that each GO, GOP, TO and TOP agree on the specifics of implementing these new requirements for each GIF? Has the Ad Hoc Group considered adding a requirement to mandate execution of an Agreement or Procedure between the GO, GOP, TO and TOP to ensure minimal specific actions that would guarantee compliance with each GIF Requirement?
<p><b>Response:</b> The SAR DT thanks you for your comment. The SAR has been modified to allow the SDT the option of merging the changes into one new standard or an existing standard(s).</p>		
American Transmission Company	Yes	
Bonneville Power Administration	Yes	
Competitive Power Ventures, Inc.	Yes	
Detroit Edison Company	Yes	
Duke Energy	Yes	
El Dorado Energy LLC	Yes	
Electric Market	Yes	

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Organization	Yes or No	Question 2 Comment
Policy		
Energy Standards Working Group	Yes	
Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners	Yes	
ERCOT ISO	Yes	
Independent Electricity System Operator	Yes	
Kansas City Power & Light	Yes	
Manitoba Hydro	Yes	
Mesquite Power	Yes	
Midwest ISO Standards Collaborators	Yes	
North Carolina Electric Membership Corporation	Yes	
PSEG Companies	Yes	



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Organization	Yes or No	Question 2 Comment
Sempra Generation	Yes	
SERC Planning Standards Subcommittee	Yes	
South Carolina Electric and Gas	Yes	
Southern California Edison co.	Yes	
Tenaska, Inc.	Yes	
Entegra Power Group LLC	Yes	<p>BUT, FAC-003 SHOULD BE APPLIED IN A REASONABLE MANNER. MORE DETAIL SHOULD BE PROVIDED THAN IT WOULD APPLY FOR MORE THAN 2 SPANS. WHAT IF THERE ARE 3 SPANS, BUT ONLY A QUARTER MILE IN DISTANCE WHICH IS TOTALLY VISIBLE FROM THE GIF. THE SDT SHOULD MAKE SOME REASONABLE CONCESSIONS FOR THESE SITUATIONS, OR ALLOW THE GIF TO DOCUMENT THE SOUND REASONING USED IN NOT IMPLEMENTING FAC-003 TO THE EXTENT REQUIRED BY THE EXISTING STANDARD. A REASONABLE VEGETATION MANAGEMENT PROGRAM SHOULD BE ADEQUATE. MORE DETAIL AND SPECIFICS DESCRIBING WHAT ADEQUATE TRAINING IS FOR PER-002.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT.</p>		
Pepco Holdings, Inc - Affiliates	Yes	<p>Defining “Generator Interconnection Facility” in the glossary is a good idea. Going beyond this to specifically note this term in so many other standards seems unnecessary since other individual devices are not noted in so many other locations. If “Generator Interconnection Facility” is included in all other Generating Facilities, this may simplify the process.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
First Wind	Yes	<p>The proposed SAR modification set is the responsible approach to resolve gaps Generator Interconnection Facility gaps identified by the industry. The functions required of an Owner(s) and Operator(s) of facilities used to connect generation to the</p>

**Consideration of Comments on Generator Requirements at the Transmission Interface — Project 2010-07**

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Organization	Yes or No	Question 2 Comment
		BES (Generator Interconnection Facilities) are not the same as the functions required to own and operate Transmission and should not be considered to be the same. We commend the task force for coming up with a reasonable approach that directly addresses reliability without requiring GO and GOPs to perform activities that have no bearing on the reliability of the BES.
<b>Response:</b> The SAR DT thanks you for your comment.		

**3. Do you agree with the proposed NERC Glossary additions or revisions? If you disagree with one or more of the proposed new or modified definitions, please provide a revision that would make the definition acceptable to you.**

**Summary Consideration:** While a majority of comments did not challenge the need for the proposed new definitions, some did suggest modifications to those new terms, as well as to some existing terms defined in the *NERC Glossary of Terms*. Given this, the SAR DT modified the SAR to make it clearer that the SDT can adopt proposals as indicated in the report or modify them to address stakeholder concerns expressed in responses to the SAR DT questionnaire.

Organization	Yes or No	Question 3 Comment
Xcel Energy		Should the definition of Generator Interface Facility indicate that no BES (or any) loads be tapped between the generator and the GIF operational interface?
<b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT.		
Independent Electricity System Operator	No	(1) Generator Operator: We agree with the first sentence of the definition for Generator Operator, but do not agree with the need for the second sentence. The first sentence already states inclusion of Generator Interconnection Facility. The first part of the second is simply a repeat of this change. The latter part of the second sentence is a requirement that should be stipulated in an appropriate standard. We suggest to strike out the second sentence. (2) Generator Interconnection Facility: The Sole-use facilities should include those which transmit power to radial customer loads if such facilities do not form a part of the connection to multiple transmission facilities that are subject to network power flows.
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		
ISO RTO Council Standards Review Committee	No	(1) Generator Operator: We agree with the first sentence of the definition for Generator Operator, but do not agree with the need for the second sentence. The first sentence already states inclusion of Generator Interconnection Facility. The first part of the second is simply a repeat of this change. The latter part of the second sentence is a requirement that should be stipulated in an appropriate standard. We suggest to strike out the second sentence.
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		
Duke Energy	No	<ul style="list-style-type: none"> <li>o The definitions of Generator Owner and Generator Operator should not be revised, because every Generator Owner and Generator Operator may not own and operate a Generator Interconnection Facility, as the revised definitions imply. The revised definition of Generator Operator also adds a coordination requirement which is more properly included in the requirements of a standard.</li> <li>o While we are sensitive to the fact that this SAR is attempting to close a reliability gap, we believe that the definition of</li> </ul>

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Organization	Yes or No	Question 3 Comment
		<p>Generator Interconnection Facility is too broad. The Standard Drafting Team should consider limiting it to the voltages defined for the Bulk Electric System, and other facilities as deemed critical by the Regional Entity. Also, how does the Regional Entity deem a facility “critical”?</p> <p>o The Right-of-Way (ROW) definition should spell out TO and GO. Suggested rewording: “A corridor of land on which electric lines may be located. The Transmission Owner or Generator Owner which owns the lines may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain the lines.”</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
<p>Public Utility District #1 of Clark County</p>	<p>No</p>	<p>Clark Public Utilities believes the proposed definitions do not provide the necessary amount of guidance and clarity. The proposed definitions and standards revisions are being considered because of the potential impacts of a 26-mile 500 kV Generation Interconnection Facility. The proposed definition for the term “Generation Interconnection Facility” will include the 26- mile interconnection as well as a host of other types of interconnections that should not be considered in this effort. Clark’s generator is attached to the transmission grid by slack span (less than 100’) between the high side of the GSU (owned by the generator) and a circuit breaker (owned and operated by the Transmission Operator) located within the Transmission Operators switchstation. There are no operable components in the slack span. Clark believes the currently proposed standards actions are overly broad. The definitions and applicability of these standards must be narrowed. Clark proposes the following definition for Generator Interconnection Facility: Generator Interconnection Facility Sole-use facility for the purpose of connecting the generating unit(s) to the transmission grid. In this regard, the sole-use facility only transmits power associated with the interconnecting generator, whether delivered to the grid or delivered to the generator for station service or auxiliary load, or delivered to meet cogeneration load requirements. Generator Interconnection Facilities shall not include lines that are less than or equal to two spans in length or lines that the host Transmission Operator has agreed to include as part of the transmission system it operates.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
<p>Kansas City Power &amp; Light</p>	<p>No</p>	<p>I believe the intent of what has been proposed here is to define the term, “Generator Operator” to mean the Operator that operates units directly at a power station. With that in mind, although the proposed definition is close, I believe the interaction with the Transmission Operator only in the definition makes this confusing. Recommend consideration of the following definition: The entity that operates generating unit(s) and the Generator Interconnection Facility and performs the functions of supplying energy and reactive power as directed by the Balancing Authority and the Transmission Operator. The Generator Operator may also operate the Generator Interconnection Facility and is responsible for coordinating with the Balancing Authority and the Transmission Operator when the facility is energized or about to be energized to/de-energized from the transmission system. In addition, recommend adding the generating station property line to the definition for Generator Interconnection Facility for clarity: Sole-use facility that leaves generator property line for the purpose of connecting the generating unit(s) to the transmission grid. In this regard, the sole-use facility only transmits power</p>

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Organization	Yes or No	Question 3 Comment
		associated with the interconnecting generator, whether delivered to the grid or delivered to the generator for station service or auxiliary load, or delivered to meet cogeneration load requirements.
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		
American Electric Power	No	It is unclear if the Generator Interconnection Facility definition only includes facilities at 100 kV or greater or those deemed critical to the Bulk Electric System by the Regional Entity.
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		
North Carolina Electric Membership Corporation	No	<p>NCEMC seeks clarification from the ad hoc team regarding the definition of Generation Interconnection Facility (GIF), especially regarding the option for ownership of the GIF. The way the definition currently reads leaves the interpretation that it might be optional for the Generator Operator to own the GIF. We are not sure that the Ad Hoc team intended this possible conclusion, which in our opinion, could completely change the scope of this SAR (in the case where the GOP does NOT own the GIF). If that is the intent of the Ad Hoc team or SDT, then the definition of Generator Operator should be changed to reflect the "option" of the GOP owning the GIF versus someone else like the Transmission Owner/Operator. Also, the second sentence of the GOP definition is not needed in our opinion since it is a requirement of the standards and as such requirements are not usually a part of the NERC definition.</p> <p>Other definitions we suggest changing are as follows:Vegetation Inspection - The systematic examination of a Right-of-Way to document vegetation conditions. The main reason for the change in definition for ROW was the proposed use of the non-capitalized term "electric line". Since the use of that phrase sometimes means distribution lines as well as transmission, we suggest staying with the capitalized NERC terms for better clarity.Right-of-Way (ROW) - A corridor of land on which a Transmission Line or Generator Interconnection Facility may be located. The owner of the Transmission Line or Generator Interconnection Facility may own the land in fee, own an easement, or have certain franchise,prescription, or license rights to construct and maintain lines.</p>
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		
Prairie Power, Inc.	No	PPI agrees with the first and existing sentence of the Generator Operator definition. However, the first part of the second sentence regarding operating the Generator Interconnection Facility is redundant with the first sentence. The second portion of the second sentence regarding coordinating with the Transmission Operator has been established already in TOP-001 R7.1 and TOP-003 R1.1 for the purpose of this project.
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		

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Organization	Yes or No	Question 3 Comment
California ISO	No	<p>The definition for “Generator Interconnection Facility” (GIF) is not consistent with either Conclusion #1 of the Adhoc Group’s final report, or with “Applicability 4.5” added under FAC-003-1. Conclusion #1 mentions “Generator Interconnecting Facilities operating at a voltage of 100 kV or greater or those deemed critical to the Bulk Electric System by the Regional Entity...” and Applicability 4.5 mentions “Generator Interconnection Facility above 200 kV... or are otherwise deemed critical by the Regional entity below 200 kV...”. In both these instances it appears that the Adhoc Group is emphasizing those Generator Interconnection Facilities that are either part of the Bulk Electric System (BES) or deemed critical by the Regional entity. Therefore, we suggest modifying the definition as follows:First sentence, after the word grid, add “above 200 kV or otherwise deemed critical by the Regional entity below 200 kV”.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
Manitoba Hydro	No	<p>The definition for Generator Interconnection Facility does not fully include the recommendations of the Ad Hoc Group Conclusions. The first conclusion states that the facility must be 100 KV and above and more importantly that if there is power flows through this station that do not belong to the generators or their exclusive station loads, then this station becomes a TO responsibility.The definition of Transmission somewhat covers the above statement, but still need clarity.Example:Transmission - An interconnected group of lines and associated equipment in which network powerflows through this station are associated with the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems. Generator Interconnection Facility will not contain any of the above criteria.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
Constellation Power Source Generation Inc.	No	<p>The term “point of interconnection” must be used in the glossary definitions of a “Generator Interconnection Facility” and “Generator Interconnection Operational Interface.” It is a common industry term that is widely understood, and is even being used in the revision to FAC-008. Using the term “point of interconnection” would further clarify the new glossary definitions. Here are the proposed changes:Generator Interconnection Facility (NEW)Sole-use facility for the purpose of connecting the generating unit(s) to the transmission grid. In this regard, the sole-use facility only transmits power associated with the interconnecting generator, whether delivered to the grid or delivered to the generator for station service or auxiliary load, or delivered to meet cogeneration load requirements.The Generator Interconnection Facility is physically defined as the facility and its encompassing equipment beginning at the low side of the Generator Step Up to the point of interconnection. Generators connected to the same interconnection facility with different Generator Operators must coordinate operations. Generator Interconnection Operational Interface (NEW)Location at which operating responsibility for the Generator Interconnection Facility changes between the Transmission Operator and the Generator Operator.This location is known as the point of interconnection.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Because of potential confusion with language in various interconnection agreements, the SAR DT will</p>		

Organization	Yes or No	Question 3 Comment
not make changes to this definition and will defer to the SDT.		
Midwest ISO Standards Collaborators	No	We agree with the first sentence of the definition of Generator Operator. However, the first part of the second sentence regarding operating the Generator Interconnection Facility is redundant with the first sentence. The second portion of the second sentence regarding coordinating with the Transmission Operator is a requirement and already established in requirement X.
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		
First Wind	No	<p>We recommend the definition of Generator Interconnection Facility be modified.</p> <p>”Generator Interconnection Facility (NEW)A facility used for the sole purpose of connecting the generating unit(s) to the transmission grid. In this regard, the sole-use facility only transmits power associated with the interconnecting generator(s), whether delivered to the grid or delivered to the generator(s) for station service or auxiliary load, or delivered to meet cogeneration load requirements.</p> <p>The purpose of the above modification is to account for the situations where a Generator Operator may have many units, such as wind turbines, all using the same Generator Interconnection Facility to connect to the transmission grid. Additionally, we feel it is irrelevant if the Generating Unit is owned by one or the same owners. Two scenarios explain why multiple generators using the same Generator Interconnection Facility does not serve a function of a TO or TOP.</p> <ul style="list-style-type: none"> <li>• Scenario 1Each Generator Operator is connected to the Transmission Operator through an independent Generator Interconnection Facility. There is no need for the Generator Operators to coordinate their operations with one another because their operations do not impact common facilities. However, there may be a need for the Transmission Operator to coordinate its instructions to the Generator Operators (if they issue voltage schedules, for example). When it becomes necessary for the Transmission Operator to communicate instructions to the Generator Operators, it is necessary for the Transmission Operator to communicate with each of the Generator Operators.</li> <li>• Scenario 2Generator Operator A is connected independently, but Generator Operators B and C share a common Generator Interconnection Facility. In this case, it is necessary for Generators B and C to coordinate their operations. It is not necessary to designate either GO_B or GO_C as the “operator” of the Generator Interconnections Facility. Rather, it is most appropriate to place the obligation to coordinate operations on both parties. By placing the obligation on both parties, they share an equal burden to comply with the applicable standards.Placing the obligation to coordinate operations on both GO_B and GO_C does not increase the burden to the Transmission Operator.</li> </ul> <p>If there is trouble at the point of interconnect substation, the Transmission Operator might need to coordinate operations with GO_A, GO_B and GO_C in either Scenario 1 or Scenario 2. If in Scenario 2, the Transmission Operator only issued</p>

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Organization	Yes or No	Question 3 Comment
		<p>instructions to GO_A and GO_B, they could not be sure that GO_C would receive the instructions. Furthermore, since GO_B is not a Transmission Operator, they lack the authority to issue instructions to GO_C.</p> <p>We recommend an additional requirement to resolve coordination between generators. For example “Generator Operators interconnected through a common Generator Interconnection Facility shall coordinate their operations.”</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
<p>SERC Planning Standards Subcommittee</p>	<p>No</p>	<p>We suggest 3 alternate modified definitions:</p> <p>Right-of-Way (ROW)A corridor of land on which a Transmission Line or Generator Interconnection Facility may be located. The owner of the Transmission Line or Generator Interconnection Facility may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.</p> <p>Vegetation InspectionThe systematic examination of a Right-of-Way to document vegetation conditions.The main reason for the change in definition for ROW was the proposed use of the non-capitalized term "electric line". Since the use of that phrase sometimes means distribution lines as well as transmission, we suggest staying with the capitalized NERC terms for better clarity.</p> <p>Generator OperatorThe entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services. The Generator Operator may also operate the Generator Interconnection Facility. The main reason for the change in the definition for Generator Operator was that the 2nd sentence in the proposed definition was a requirement and not a true definition. The other change was to allow for the case where the Generator Operator was not the operator of the Generator Interconnection Facility.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
<p>AmerenUE, Power Operations Services</p>	<p>Yes</p>	
<p>American Transmission Company</p>	<p>Yes</p>	
<p>Bonneville Power Administration</p>	<p>Yes</p>	



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Organization	Yes or No	Question 3 Comment
Detroit Edison Company	Yes	
El Dorado Energy LLC	Yes	
Electric Market Policy	Yes	
Entegra Power Group LLC	Yes	
Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners	Yes	
Florida Municipal Power Agency	Yes	
Ingleside Cogeneration, LP	Yes	
Mesquite Power	Yes	
PSEG Companies	Yes	
Sempra Generation	Yes	
South Carolina Electric and Gas	Yes	
Tenaska, Inc.	Yes	

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Organization	Yes or No	Question 3 Comment
Pepco Holdings, Inc - Affiliates	Yes	<p>“Generator Interconnection Facility” is useful to allow GOs to be distinguished from TOs and their responsibilities. “Generator Interconnection Operational Interface” is also known as the “Point of Interconnect” by the RTO. This may be an alternate name that could be used to make things standard.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Because of potential confusion with language in various interconnection agreements, the SAR DT will not make changes to this definition and will defer to the SDT.</p>		
Southern California Edison co.	Yes	<p>Additional clarification would be useful as it/ they would cut down on future requests for interpretation... i.e provide a specific threshold for the proposed Generator interconnection Facility definition</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT.</p>		
Energy Standards Working Group	Yes	<p>In particular we support the revised definition of the Generator Interconnection Facility, which has appropriately incorporated our comments from the draft of the Team’s report</p>
<p><b>Response:</b> The SAR DT thanks you for your comment.</p>		

**4. Do you agree with the proposed *new* requirements intended to add clarity around expectations for generator owners and operators at the transmission interface?**

**Summary Consideration:** A number of responses expressed concern about the need for various proposed new requirements. An in-depth review of the comments, however, indicated that most of the concerns could be addressed by the SDT. As a result, many of these comments will be referred to the SDT for their consideration, including final resolution of which standards need to be modified. Revisions to the SAR also allow the SDT the option of merging the changes into one new standard or an existing standard(s).

Organization	Yes or No	Question 4 Comment
Kansas City Power & Light	No	<ul style="list-style-type: none"> <li>o PER-001, R1: The language proposed for PER-001, R1, infers the Generator Operator is able to take independent actions regarding the “Generation Facility” and the Generator Interconnection Facility. There is no definition for Generation Facility in this proposal or currently in the NERC Glossary. At any rate, do not agree with the Generator Operator taking any independent actions other than those to monitor and maintain the safe operation of a generating unit for the production of energy and reactive power.</li> <li>o PER-002, R3 (Proposed here): This infers again the Generator Operator taking independent actions with regard to equipment within the Generator Interconnection Facility. Although, the Generation Interconnection Facility is defined properly, that does not mean the Generator Operator is the control authority over that equipment. It is not uncommon for the Generator Operator to operate equipment within the Generator Interconnection Facility at the direction of the Transmission Operator. Recommend consideration be given to modify this requirement to reflect that.</li> <li>o TOP-001, R9 and R10 (Proposed here): This infers again the Generator Operator taking independent actions with regard to equipment within the Generator Interconnection Facility. Although, the Generation Interconnection Facility is defined properly, that does not mean the Generator Operator is the control authority over that equipment. It is not uncommon for the Generator Operator to operate equipment within the Generator Interconnection Facility at the direction of the Transmission Operator. Recommend consideration be given to modify these requirements to reflect the Transmission Operator can be the authority over the equipment within the Generation Interconnection Facility but that the Generator Operator may operate that equipment at the direction of the Transmission Operator.</li> </ul>
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		
American Electric Power	No	AEP believes that the only new requirement that should be addressed is in reference to FAC-003. AEP does not see benefit in expanding the scope of EOP-003, PER-001, and PER-002. With respect to TOP-004, AEP does not feel the added requirement is necessary as the Generator Interconnection Facility should be adequately sized to handle the output of the generator. The added requirement in TOP-008 for notification is redundant with other obligations for the GOP to notify other entities, such as in COM-002 and TOP-003.

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Organization	Yes or No	Question 4 Comment
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		
American Transmission Company	No	Clarify the definition of generator interconnection facility to include who this applies to as shown in the conclusions above in #3. A Generator Interconnection Facility is considered as though part of the generating facility specifically for purposes of applying Reliability Standards to a Generator Owner or Generator Operator.
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		
E.ON U.S.	No	E.ON U.S. has already determined a Division of Responsibilities between the GO/TO and therefore does not see the need for auditable reliability standards to be added between the GO/TO. Also, it is not necessary to include the phrase “including the Generator Interconnection Facility” in all the applicable requirements. Since the term Generator Interconnection Facility is proposed to be included in the Glossary definitions for Generator Operator, then it would be redundant to also add the phrase throughout the applicable standards.
<b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT.		
Public Utility District #1 of Clark County	No	<p>Many of the new requirements place excessive demands on generators that do not increase system reliability.</p> <p>In EOP-003 Generator Operators are added to the applicability and as a result R7 is a newly applicable requirement to Generator Operators. However, this requirement now implies that Generator Operators are required to engage in the coordination efforts (with the BA and TOP) of automatic underfrequency load shedding. Generators do not have the option of determining what levels of frequency to ride through and what levels of frequency to trip on. Those quantities are defined by the RC and the BA and Generator Operators are required to have generator protection system settings that allow this ride through. Generators should have frequency and voltage ride through requirements that are coordinated with automatic load shedding programs by the RC, BA and/or TOP but should simply be required to comply with these requirements and should not have a role in the coordination. The comments in the GOTO Final report indicate that this addition is required to ensure that a generator frequency trip set point is appropriately included in the currently required coordination between the BA and TOP. Clark believes that generators should not participate in the coordination but simply be required to comply with frequency ride through requirements dictated by the RC, BA and/or TOP.</p> <p>Clark believes that FAC-002 clearly applies to Generator Owners and this standard requires that generator integration facilities address reliability impacts in the interconnected transmission system. Additionally, the proposed change to EOP-003 appears to have nothing to do with the issue at hand (i.e. removal of TOP status to a generator because of a Generator Interconnection Facility).</p> <p>Clark believes it is inappropriate to make EOP-003 applicable to Generator Operators and to imply that a Generator</p>

Organization	Yes or No	Question 4 Comment
		<p>Operator has any participation in coordination of underfrequency load shedding other than to comply with frequency ride through requirements of the RC, BA and/or TOP.</p> <p>Clark agrees that the changes to FAC-003 are appropriate, will lead to increased reliability and do not result in unnecessary reporting or paperwork. The applicability section clearly limits the scope of what Generation Interconnection Facilities would be included in this standard by having a “two span” limit in the length of the facility. This limit appropriately will exclude those generators that have arranged for a Transmission switchstation owned and operated by a Transmission Operator located immediately adjacent to the generator.</p> <p>In IRO-005, R13, the standard proposes to require a Generator Operator to immediately inform the TOP of status changes to SPS. While Clark is not opposed to this change, it is unclear why the issue at hand (i.e. removal of TOP status to a generator because of a Generator Interconnection Facility) has led to this addition. The SAR implies that the industry need leading to the SAR is the “registration of Generator Owners and Generator Operators as Transmission Owners and Transmission Operators, based on the facilities that connect the generators to the interconnected grid.” IRO-005, R13 does not appear to have any connection to this industry need.</p> <p>In PER-001, Generator Operators are added to the applicability and as a result of the new R2 Generator Operators will be required to demonstrate the authority of operating personnel over Generation Facilities and Generation Interconnection Facilities. This level of authority is unnecessary. Transmission Operators already have this authority (refer to PER-001, R1). Generator Operators are already required to comply with reliability directives issued by RCs, BAs, and TOPs in other reliability standards. The requirement to demonstrate that a generator needs this authority over its generating facility is unnecessary and has no connection with the industry need the SAR is based on. A generator operator has authority over its generator by virtue of its registration as a Generator Operator. The need for further proof that a GOP can operate generation facilities for which it is a registered GOP has not been demonstrated. The requirement to demonstrate that a generator needs authority over a Generation Interconnection Facility is; for the same reason, unnecessary. A generator operator has authority over its generator by virtue of its registration as a Generator Operator for that facility. The need for further proof that a GOP can operate Generation Interconnection Facilities for which it is a registered GOP has not been demonstrated.</p> <p>In PER-002, Generator Operators are added to the applicability and as a result of the new R3 Generator Operators will be required to demonstrate training programs similar to TOP training requirements. Clark is not opposed to training its GOP personnel; however, including the training program within the PER-002 training requirements elevates this training to a level that has not been demonstrated to be necessary in all cases. Currently, this requirement is applicable to a TOP. By removing the TOP classification to certain GO/GOP registered entities that are only a TOP by virtue of Generation Interconnection Facilities, the potential exists that inadequately trained personnel may be directing the operation of a Generation Interconnection Facility. However, as stated earlier, when the Generation Interconnection Facility is short in length and more importantly when this facility has no devices which can be operated (i.e. direct connection between the generator step-up transformer or generator protection circuit breaker (owned or</p>

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Organization	Yes or No	Question 4 Comment
		<p>operated by the GOP) and the TOP owned and operated transmission breaker) there is no gap in having adequately trained personnel operating transmission facilities. Clark believes the applicability section should include minimal limits for applicable Generation Interconnection Facilities or that the definition of Generation Interconnection Facilities should be amended such that PER-002 applicability is limited to GOPs that own facilities that are similar in nature to the New Harquahala Generation Interconnection Facilities that have led to this SAR.</p> <p>The proposed changes to TOP-004 are confusing. The proposal does not add GOP in the applicability section but the newly proposed R7 appears to obligate GOPs. The requirement should be revised to obligate a TOP to ensure that a GOP operates within its applicable limits. These limits should have already been established.</p> <p>In FAC-008 Transmission Owners and Generator Owners are required to have a ratings methodology.</p> <p>In FAC-009 TOs and GOs are required to calculate facility ratings. In both of these standards, documentation is to be made available to RCs, TOPs, PAs and TPs that have responsibility. At the very least, the applicability section of a standard should be coordinated with the entities having obligations due to the requirements of a standard.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.)</p>		
Luminant	No	<p>No, for the bulk of the Generator Owners whose Generation Interconnection Facilities (GIF) are connected in close proximity (i.e., one-half mile or less) to the BES, the requirements will only add additional unduly burdensome documentation, paperwork and compliance risk, with no reliability benefit</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
Independent Electricity System Operator	No	<p>Please see our comments under Q5 where we comment on both the additions and modifications to the standards.</p>
ISO RTO Council Standards Review Committee	No	<p>Please see our comments under Q5 where we comment on both the additions and modifications to the standards.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
Prairie Power, Inc.	No	<p>PPI considers the phrase “for SPS relay or control equipment under its control” to be confusing and ambiguous in the new requirement IRO-005 R13. We suggest deletion of this phrase maintains the intent of the requirement and removes the unclear reference to the subject associated with the word “its”.</p>

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Organization	Yes or No	Question 4 Comment
		<p>PPI questions why the sub-elements of new requirement TOP-001 R9 are stipulated in bullet item format rather than sub-requirement format.</p> <p>PPI agrees with the first portion of new requirement PER-001 R2. Regarding the second portion of new PER-001 R2, the Generator Operator is already required to comply with Reliability Coordinator directives as established in IRO-001 R8 and TOP-001 R3, and further the Generator Operator is already required to comply with Transmission Operator directives also as established in TOP-001 R3. PPI does not see any benefit in reiterating the Generator Operator responsibility and authority to follow directives in this new requirement. PPI would suggest stipulating the Generator Operator be responsible for following directives of the Balancing Authority in a separate Requirement or sub-requirement, and not lumped into this new requirement.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT. The bulleted items in TOP-001 R9 should have been numbered. We'll pass this comment on to the SDT.</p>		
Duke Energy	No	See detailed comments under Question 5 below.
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
AmerenUE, Power Operations Services	No	See response to Item #2.
<p><b>Response:</b> The SAR DT thanks you for your comment. The SAR has been modified to allow the SDT the option of merging the changes into one new standard or an existing standard(s).</p>		
Midwest ISO Standards Collaborators	No	The requirement additions to the TOP standards parallel requirements that the Real-Time Operations standards drafting team has already proposed for removal. This project needs to be coordinated with the Real-Time Operations project.
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
Tenaska, Inc.	No	TOP-001 R10 should be amended such that the proposed R10 reads as follows: The Transmission Operator shall have decision-making authority over operation of the Generator Interconnection Operational Interface at all times in order to preserve interconnection reliability, unless by exercising that authority such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability

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Organization	Yes or No	Question 4 Comment
		Coordinator or Transmission Operator can implement alternate remedial actions.
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		
North Carolina Electric Membership Corporation	No	<p>We agree with most of the new requirements with the exception of two:</p> <p>1) New requirement R9 of TOP-001 appears to be very similar to existing requirements of TOP-001 (req R7) and TOP-003 (req R1). Further clarification is needed to distinguish the differences between this new requirement and existing requirements.</p> <p>2) New requirement R5 of TOP-008 directs the GOP to disconnect the GIF when “safety is jeopardized” or... which triggers the immediate question: Who’s safety does the Ad Hoc group refer to, the personnel of the GO/GOP or the safety of the transmission system or its personnel or both possibly? Please clarify. If it the safety of the transmission, its personnel or the system grid in general, then why would it not be the TOP's responsibility to provide a directive of this nature since the TOP would have a greater perspective/visibility than the GO/GOP of the system operating conditions in real time?</p>
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		
Energy Standards Working Group	No	<p>We are supportive of most of the new requirements being suggested with the following two exceptions:</p> <p>IRO-005 R13 which states:R13. The Generator Operator shall immediately inform the Transmission Operator of the status ofthe Special Protection System, including any degradation or potential failure to operate as expected for SPS relay or control equipment under its control.We believe that this proposed additional requirement is redundant as it is already covered by the requirements of PRC-001-1</p> <p>ANDTOP-001 R10 which states:The Transmission Operator shall have decision-making authority over operation of theGenerator Interconnection Operational Interface at all times in order to preserveInterconnection reliability.</p> <p>We would amend the proposed R10 as follows: The Transmission Operator shall have decision-making authority over operation of the Generator Interconnection Operational Interface at all times in order to preserve interconnection reliability, unless by exercising that authority such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.</p>
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		



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Organization	Yes or No	Question 4 Comment
Electric Market Policy	No	We feel it is not necessary to include the phrase “including the Generator Interconnection Facility” in all the applicable requirements. The term Generator Interconnection Facility is proposed to be included in the Glossary definitions and the proposed definition of Generator Operator includes the following language “also operates the Generator Interconnection Facility and is responsible for coordinating with the Transmission Operator when the facility is energized or about to be energized to/de-energized from the transmission system” which we feel is sufficient and superior to having the phrase repeated throughout the applicable standards.
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		
First Wind	No	We feel it is not necessary to include the phrase “including the Generator Interconnection Facility” in all the applicable requirements. The term Generator Interconnection Facility is proposed to be included in the Glossary definitions and the proposed definition of Generator Operator includes the following language “also operates the Generator Interconnection Facility and is responsible for coordinating with the Transmission Operator when the facility is energized or about to be energized to/de-energized from the transmission system” which we feel is sufficient and superior to having the phrase repeated throughout the applicable standards.
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		
California ISO	Yes	
Competitive Power Ventures, Inc.	Yes	
El Dorado Energy LLC	Yes	
Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners	Yes	
Florida Municipal Power Agency	Yes	
Ingleside Cogeneration,	Yes	

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Organization	Yes or No	Question 4 Comment
LP		
Manitoba Hydro	Yes	
Mesquite Power	Yes	
PSEG Companies	Yes	
Sempra Generation	Yes	
SERC Planning Standards Subcommittee	Yes	
South Carolina Electric and Gas	Yes	
Southern California Edison co.	Yes	Additional clarification would be useful as it/ they would cut down on future requests for interpretation.
<b>Response:</b> The SAR DT thanks you for your comment.		
Pepco Holdings, Inc - Affiliates	Yes	Application of FAC-003 for Gen Interconnect Facilities that are "two spans, generally 1/2 mile or more past the property line" is reasonable as long as the "property line" remains in the definition. OK.
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		
Constellation Power Source Generation Inc.	Yes	Constellation agrees with the proposed new requirements in principal. However, further clarity is needed in the requirements so that there isn't any added confusion. Either an implementation plan or a "frequently asked questions" document would be recommended.
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		
Bonneville Power Administration	Yes	However, believe there is a problem with #8 referring to TOP-008. The solution to the generator facility line overload may be a transmission system problem so the Generator should not disconnect unless the TOP directs it to do

**Consideration of Comments on Generator Requirements at the Transmission Interface — Project 2010-07**

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Organization	Yes or No	Question 4 Comment
		so(confer unless a safety issue). Also, TOP-001 needs careful work. The transmission system doesn't want environmental issues turning off generators during emergency or critical transmission conditions.
Entegra Power Group LLC	Yes	SEE COMMENTS FOR QUESTION 2.
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		

**5. Do you agree with the proposed *modified* requirements intended to add clarity around expectations for generator owners and operators at the transmission interface?**

**Summary Consideration:** A number of responses expressed concern about the proposed modifications. An in-depth review of the comments indicated that most of the concerns could be addressed by the SDT during the standards drafting process. Based on discussions with FERC and NERC staffs regarding previous Commission actions and NERC compliance filings, the SAR DT modified the SAR to give the SDT the flexibility to consider further modifications not identified in the Ad Hoc Report.

Organization	Yes or No	Question 5 Comment
Independent Electricity System Operator		<p>(1) We realize that the SDT needs to make changes to “approved standards” but there are a number of standards involved in this project whose newer versions have either received the BoT approval, or about to be adopted by the BoT or at the stage of being finalized or balloted. To make changes to the soon to be outdated versions is confusion and will require a subsequent change when FERC approves the standards. We therefore suggest the SDT to also mark up those which have newer versions already or soon to be adopted by the BoT and those that are being balloted. Alternatively, the SDT may want to post the changes to those FERC approved standards only, and defer actions on those that have not been approved by FERC and those that are being revised/balloted until FERC approves them.</p> <p>(2) EOP-001: R7.3 has been changed to add the term “..., including outages to the Generator Interconnection Facility, to maximize .....”. It is not clear whom the TOP and the BA should coordinate with and it does not place a requirement on the entity that is responsible for the Generator Interconnection Facility outage planning and scheduling. We suggest to add the appropriate responsible entity (Generator Owner?) to the Applicability Section, and add this entity to R7.3.</p> <p>(3) In EOP-008 R1.3, is it the intent of the revised requirement that the plan address monitoring and control of ALL Generator Interconnection Operational Interface[s] or just the critical ones (as with the critical transmission facilities)?</p> <p>(4) R10 of TOP-001 is not written in the form of a requirement. We suggest replacing “have” with “exercise”. Thus, the requirement would read “The Transmission Operator shall exercise decision-making authority over operation of the Generator Interconnection Operational Interface...”</p> <p>(5) TOP-004: The Applicability Section needs to be revised to add Generator Operator to reflect the new requirement R7. We also suggest the SDT to evaluate if there is an alternative or more suitable place for this requirement than the TOP standard.</p> <p>(6) A number of standards are missing their VSLs. Most VSLs have similar wording in the requirements so many of them will need to be revised to reflect changes to the requirements proposed in this project.</p>

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Organization	Yes or No	Question 5 Comment
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT. The redlines were only intended to provide stakeholders with an idea of the proposed scope of changes – the team recognizes that any new/revised requirement may result in associated changes to the VRFs, Time Horizons, VSLs, data retention, measures, etc.</p>		
<p>Energy Standards Working Group</p>	<p>No</p>	<p>Comments: see my note re FAC-003</p> <p>We are supportive of the modified requirements being suggested with the following exception:</p> <p>FAC-003:We offer the following suggested changes for greater clarity.</p> <p>4. Applicability:Replace the proposed sections 4.4 and 4.5 with the following:4.4. Generator Owner that owns a Generator Interconnection Facility above 200 kV that exceed two spans from the generator property line or are below 200 kV and deemed critical to the reliability of the electric system by the Regional Entity (subject to the two-span criteria.)</p> <p>Furthermore, the Standard Drafting Team should insure that in drafting the requirements and subsequent sections of the standards, it is clear that the use of the words “Generator Owner” refers only to the subset of Generator Owners as specified by section 4.4, not to all Generator Owners included in the NERC Registry.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
<p>Constellation Power Source Generation Inc.</p>	<p>No</p>	<p>Constellation agrees with the proposed changes for BAL-5, EOP-1, EOP-4, EOP-8, FAC-1, FAC-8, FAC-9, IRO-5, MOD-10, MOD-12, PER-1, PRC-1, PRC-5, TOP-1, TOP-2, TOP-3, VAR-1, and VAR-2. Furthermore, the changes made to CIP-2 are especially valuable in that the clarity it brings with the added terminology would assist in identifying individual assets.</p> <p>Constellation does not agree with (or has comments for) the proposed changes to:</p> <ul style="list-style-type: none"> <li>oEOP-3 - GOs/GOPs should not be included in this standard</li> <li>oFAC-3 - Constellation agrees in principal with this change, but further work is needed in regards to which GOs fall into this category. The wording may be changed to “two or more spans exceeding ½ mile in total length,” but further discussions is needed on this topic.</li> <li>oPER-2 - Constellation agrees in principal with this change, but believes that this requirement should be combined into PRC-001 R1, and eliminate the redundancy.</li> <li>oPRC-5 - Testing of the Protection System of the Generator Interconnection Facility is not always the sole responsibility of the GO. Some verbiage attesting to that is needed. Otherwise, it is wise to include the Generator Interconnection Facility into this standard so that no gap may exist in the testing of a Protection System that may impact the BES.</li> </ul>

Organization	Yes or No	Question 5 Comment
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
E.ON U.S.	No	E.ON U.S. has already determined a Division of Responsibilities between the GO/TO and therefore does not see the need for auditable reliability standards to be added between the GO/TO.
<p><b>Response:</b> The SAR DT thanks you for your comment. Based on a review of the full body of industry comments, we believe that there is a reliability need for this SAR.</p>		
Duke Energy	No	<ul style="list-style-type: none"> <li>o General Comment - The Standards Drafting Team (SDT) will need to make sure that Measures are developed or modified to correspond to new or revised requirements of the standards.</li> <li>o Process Question - Will the SDT fold these standards revisions into other projects, or will new versions be created as part of this project?</li> <li>o FAC-003-1 - Applicability sections 4.4 and 4.5 should be combined to make it clear that the standard only applies to the Generator Owner’s GIF. Does the 2-span limit mean that there are three towers? What criteria will the Regional Entity use to deem a GIF critical? The language about the generator property line is confusing - how does it compare to the Right-of-Way (ROW) definition? In some cases the TO may own the ROW, while the GO owns the GIF.</li> <li>o FAC-008-1 - Requirement R1 raises a question regarding whether a GIF can be jointly owned by a TO and a GO. If a TO is an owner, then the GIF is not a GIF but a transmission facility, right?</li> <li>o FAC-009-1 - We don’t think revisions are needed to R1 and R2, since the term “Facilities” already implicitly includes GIF. If you don’t agree, then perhaps a more straightforward approach would be to revise the definition of “Facility” to explicitly include the GIF.</li> <li>o IRO-005-2 - We think that you don’t need to specifically add the GIF to R9 because it would have to already be included in the requirement as part of any generation outage coordination. Under R13 we would change “the Special Protection System” to “any Special Protection System”. We also note that this new R13 propagates the poor language of R12 (i.e., how does anyone define “a potential failure to operate”?).</li> <li>o PER-001-0 - Applicability section 4.3 should be expanded to make it clear that Requirement R2 only applies to the Generator Operator with respect to the GIF, and R2 should be likewise revised. The GOP is already obligated under TOP-001-1 Requirement R3 to comply with RC and TOP directives unless such actions would violate safety, equipment, regulatory or statutory requirements. Suggested rewording of Applicability section 4.3 : “Generator Operators -This standard shall apply to Generator Operators who own a Generator Interconnection Facility.” Suggested rewording of Requirement R2 : “For Generation Facility Interconnection equipment under their direct control, each Generator Operator shall provide operating personnel with the responsibility and authority to implement real-time actions and to follow reliability</li> </ul>

Organization	Yes or No	Question 5 Comment
		<p>directives of Reliability Authorities, Transmission Operators and Balancing Authorities, to ensure the stable and reliable operation of the Generation Interconnection Facility.”</p> <ul style="list-style-type: none"> <li>o PER-002-0 - Applicability section 4.3 should be expanded to make it clear that Requirement R2 only applies to the Generator Operator with respect to the GIF. Suggested rewording of Applicability section 4.3 : “Generator Operators -This standard shall apply to Generator Operators who own a Generator Interconnection Facility.”</li> <li>o PRC-001-1 - Changes to PRC-001-1 should probably not be made right now, because it is already a vague standard, and was the subject of an Interpretation (Project 2009-30) which was voted down in February.</li> <li>o TOP-003-0 - Requirement R1 and its sub-requirements are poorly written. We suggest folding R1.3 into R1 with this suggested rewording: “Generator Operators and Transmission Operators shall provide planned outage information by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection, as follows : “</li> <li>o TOP-004-2 - We question whether Requirement R7 is appropriate, since by definition the GIF is not part of the transmission system network and does not fit with the Purpose statement of this standard. If R7 is retained, then you need to add Generator Operator to the Applicability section.</li> <li>o TOP-008-1 - Need to add GOPs to the Purpose statement.</li> </ul>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
California ISO	No	<p>Please see our comments under Question 2 above. In addition, with regard to the proposed change to Standard PRC-001, the California ISO (CAISO) questions the need for a BA to understand the purpose and limitations of protection schemes associated with all of the Generator Interconnection Facilities in its area given a BA’s role is to balance load/generation/interchange which does not require the BA to operate any generator or BES facilities, or to understand the characteristics or limitations of any equipment. Any potential loss of one or more generator due to protection or equipment issues will need to be communicated by the GO or GOP to the BA for consideration in reserve calculation</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
Prairie Power, Inc.	No	<p>PPI does not agree with the modification to EOP-003 R7. The Generator Operator does not have load to be shed, therefore none to be coordinated. If the drafting team is intending to require the Generator Operator to coordinate the underfrequency relay settings on their resources with load shedding plans established by the Transmission Operator and Balancing Authority, this is an appropriate requirement. The modification, though, does not accomplish this.PPI questions why the sustained line outages reported quarterly to the RRO pursuant to FAC-003 R3 by the Generator Owner, as modified, are not reported to NERC in Requirement 4 of the same Standard.</p>

Organization	Yes or No	Question 5 Comment
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
AmerenUE, Power Operations Services	No	See response to Item #2.
<p><b>Response:</b> The SAR DT thanks you for your comment. The SAR has been modified to allow the SDT the option of merging the changes into one new standard or an existing standard(s).</p>		
Luminant	No	<p>The following comments are specific to each standard</p> <p>CIP-002 - This standard is currently under revision and any change should be addressed by the Cyber Security Standards Revision Team.</p> <p>EOP-003 - Application of this reliability standard to a GOP is incorrect. The Generator Operator has no direct responsibility for load shedding. Only the TOP and BA have load shedding responsibility.</p> <p>EOP-004 - The inclusion of GIF in this reliability standard is redundant as the GOP has responsibility for all of its facilities, including any generators. . Since generation units are not independently identified with a particular GOP, the GIF does not need to be independently identified. Also, there is a NERC project currently underway to revise this standard (Project 2009-01).</p> <p>FAC-003 - Luminant agrees this standard should apply in those instances when the generator is connected to the BES through its GIF over a substantial distance. However, the applicability of this standard to a GIF needs to specify a distance (such as one-half (½) mile from the plant property boundary) not a number of spans since the spacing between spans can vary from extensively. Defining the applicability of this standard in terms of a number of spans will create inconsistency in the application of the requirements.</p> <p>IRO-005 - New requirement R13 presumes that a Special Protection System (SPS) is the sole responsibility of a GOP, which, in most cases, it is not. Most SPS are the responsibility of the TO, not the GOP. This requirement does not define which SPS is being monitored. A requirement of this nature should define an SPS on the GIF.</p> <p>PER-001 - The addition of a requirement applicable to GOP in this standard goes well beyond the scope of this project's purpose. A NERC Standards Drafting Team, under Project 2006-01, did not add any GOP requirements to the PER standards. This proposed GOP requirement is redundant. Current NERC Reliability Standard TOP-001, R3 requires Generator Operators to follow reliability directives, as does IRO-001, R8. This proposed requirement should be deleted. It adds paperwork, documentation and compliance risk with no reliability benefit. The PER-001 standards were intended for overall grid management, not the operation of a power plant.</p>



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Organization	Yes or No	Question 5 Comment
		<p>PER-002 - The recent NERC Standards Drafting Team, under Project 2006-01, specifically declined to make this standard applicable to GOP. In addition, the 2006-01 project is retiring this standard with the adoption of the revised PER-005.</p> <p>PRC-001 - The inclusion of Generator Interconnection Facility is redundant. However, there is a current NERC Drafting team revising PRC-001 and this issue should be referred to that team.</p> <p>PRC-005 - Any revisions to PRC-005 should be referred to the current PRC-005 drafting team.</p> <p>TOP-001 - Draft Requirements R9 and R10 are extremely broad. These should only apply to narrowly defined GIFs such as long span connections or GIFs with transmission load flowing through the GIF. Care should be taken in this requirement not to duplicate requirements such as coordination of outage planning. The requirements should be specific, and not fill in the blank for the TOP or region.</p> <p>TOP-004 - Draft Requirement R7 is redundant to requirements in other standards and is not needed.</p> <p>IRO-005-2, R13, and IRO-005-3, R10, require the GOP to operate the BES to its most limiting factor, which is, by definition, implicitly within its facility ratings.</p> <p>TOP-008 - Does draft requirement R5 fit in this standard that addresses IROL and SOL? This requirement should only apply to the same long connection GIF facilities identified in TOP-003.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
Florida Municipal Power Agency	No	<p>The modification of EOP-003-1, R7 is inconsistent with the requirement. The original requirement requires the BA and TOP to coordinate with others (presumably DPs, TOs and GOPs) in their area for various automatic action (e.g., UFLS, automatic tripping of cap banks, and frequency capabilities of generators for instance). The GOP has no “area” to coordinate and no one within its area to coordinate with. So, it is the BA and TOP that coordinate within their area, not the entities embedded within the BA or TOP area. Otherwise, we ought to add at a minimum DPs, LSEs, and TOs to the list.</p> <p>The modifications to EOP-004-1 R2; FAC-001-0 R1.1; FAC-008-1; FAC-009-1; MOD-010, MOD-012, PRC-001, PRC-004; PRC-005; TOP-001-1 R7; TOP-002 R3 and R18; TOP-003 R1 and R1.1; and VAR-002 R3.2 are redundant with no need to specifically call out the Generator Interconnection Facility. The interconnection facilities are facilities and already included in the term “on its system or facilities” and “generating facilities”, etc. And, the Generator Owner and Operator are already responsible for their interconnection facilities in the definition of those Entities. Specifically calling out the interconnection facilities calls into question why other facilities are not specifically called out.</p> <p>As discussed in the response to #2 above, addition of the Generator Owner to FAC-003 over-steps Federal Power Act Section 215 since radial transmission lines to generating plants will not participate in a cascading outage since the loading of radial facilities to power plants will not change significantly with outages on the interconnected system.</p>

Organization	Yes or No	Question 5 Comment
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
<p>North Carolina Electric Membership Corporation</p>	<p>No</p>	<p>We agree with most all of the modified requirements with one exception:                      For FAC-003, regarding the "two-span criteria" or "about 0.5 miles" test for generator applicability, we would like the ad hoc team to consider providing more direction or greater specificity that makes a GIF of two or less spans to become exempt, while one of greater than two spans (0.5 mile) but less than 5 spans (0.8 miles) to suddenly become subject to the FAC-003 standard requirements. The "generator's line-of sight" rule as described in response to item #3 in the Final Report in our opinion should be clearly specified in the FAC-003 proposed standard change at a minimum to avoid mis-interpretations. Also, regarding item #10 issue in the report, we would like the ad hoc team to consider proposing a 4th proposal which would be a hybrid between Proposal 2 and Proposal 3 as reported within the Final Report which would provide a "bright-line test" as to what generators are exempt or not to the FAC-003 standard, rather than solely relying on Proposal 2 which relies on the physical attributes of the GIF in ruling out generators subject to FAC-003. If the GIF is 3-4 spans or 0.53 miles in length, but still within the "line of sight" of the GOP, then allow the GOP working with the RE and TOP to rule out smaller generators that are immaterial to the reliability of the grid.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
<p>Tenaska, Inc.</p>	<p>No</p>	<p>We are supportive of the modified requirements being suggested with the following exception related to the suggested changes on FAC-003 for which we offer the following modification for greater clarity:                      4. Applicability: Replace the proposed sections 4.4 and 4.5 with the following:                      4.4. Generator Owner that owns a Generator Interconnection Facility above 200 kV that exceed two spans from the generator property line or are below 200 kV and deemed critical to the reliability of the electric system by the Regional Entity (subject to the two-span criteria.)                      Furthermore, the Standard Drafting Team should insure that in drafting the requirements and subsequent sections of the standards, it is clear that the use of the words "Generator Owner" refers only to the subset of Generator Owners as specified by section 4.4, not to all Generator Owners included in the NERC Registry.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
<p>Midwest ISO Standards Collaborators</p>	<p>No</p>	<p>We do not agree with the modification to EOP-003 R7. The Generator Operator does not have load shed to coordinate. We believe the drafting team is intending to require the Generator Operator to coordinate underfrequency relay settings on their generators with the BA and TOP load shedding plans. We agree this is appropriate but the modification does not</p>

Organization	Yes or No	Question 5 Comment
		<p>accomplish this.</p> <p>EOP-004 R2 seems to be modified unnecessarily. System and facilities are already included in the requirement and, thus, would include the Generator Interconnection Facility.</p> <p>We do not agree adding Generator Interconnection Operational Interface to R1.3 in EOP-008. The sub-requirement already requires the contingency plan to consider generation control which would require consideration of the Generator Interconnection Operational Interface. Furthermore, there is a lack of coordination with the project to update this standard. A newer, significantly modified version of this standard has already been through an initial ballot period.</p> <p>IRO-005 R9 modifications are not needed. The requirement already requires an RC to coordinate pending generation outages. This would have to include any outage such as the Generator Interconnection Facility. Many of the changes to the TOP standard are modifying requirements that the Real-Time Operations standards drafting team has already proposed for removal. This project needs to be coordinated with the Real-Time Operations project.</p> <p>VAR-001 R8 modifications are not necessary because the TOP is already required to operate reactive generation scheduling. They can't do this without considering the Generator Interconnection Facility.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
<p>ISO RTO Council Standards Review Committee</p>	<p>No</p>	<p>While we generally agree with the proposed wording change, we have a number of comments the first of which is a timing decision issue.</p> <p>(1) We realize that the SDT needs to make changes to “approved standards” but there are a number of standards involved in this project whose newer versions have either received the BoT approval, or about to be adopted by the BoT or at the stage of being finalized or balloted. To make changes to the soon to be outdated versions is confusing and will require a subsequent change when FERC approves the standards. We therefore suggest the SDT to coordinate their changes with the other drafting teams that are working on the newer versions already or soon to be adopted by the BoT and those that are being balloted. Alternatively, the SDT may want to post the changes to those FERC approved standards only, and defer actions on those that have not been approved by FERC and those that are being revised/balloted until FERC approves them.</p> <p>(2) EOP-001: R7.3 has been changed to add the term “..., including outages to the Generator Interconnection Facility, to maximize .....”. It is not clear with whom the TOP and the BA should coordinate with and it does not place a requirement on the entity that is responsible for the Generator Interconnection Facility outage planning and scheduling. We suggest removing the changes on this requirement all together. Generator maintenance will include the Generator Interconnection Facility. These are extra words that are not needed.</p> <p>(3) A number of standards are missing their VSLs. Most VSLs have similar wording in the requirements so many of them</p>

**Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07**

Organization	Yes or No	Question 5 Comment
		<p>will need to be revised to reflect changes to the requirements proposed in this project.</p> <p>(4) We do not agree with the modification to EOP-003 R7. The Generator Operator does not have load shed to coordinate. We believe the drafting team is intending to require the Generator Operator to coordinate underfrequency relay settings on their generators with the BA and TOP load shedding plans. We agree this is appropriate but the modification does not accomplish this.</p> <p>(5) EOP-004 R2 seems to be modified unnecessarily. System and facilities are already included in the requirement and, thus, would include the Generator Interconnection Facility.</p> <p>(6) We do not agree adding Generator Interconnection Operational Interface to R1.3 in EOP-008. The sub-requirement already requires the contingency plan to consider generation control which would require consideration of the Generator Interconnection Operational Interface. Furthermore, there is a lack of coordination with the project to update this standard. A newer, significantly modified version of this standard has already been through an initial ballot period.</p> <p>(7) IRO-005 R9 modifications are not needed. The requirement already requires an RC to coordinate pending generation outages. This would have to include any outage such as the Generator Interconnection Facility.</p> <p>(8) PRC-001: We question the need for a BA to understand the purpose and limitations of protection schemes associated with all of the Generator Interconnection Facilities in its area given a BA's role is to balance load/generation/interchange which does not require the BA to operate any generator or BES facilities, or to understand the characteristics or limitations of any equipment. Any potential loss of one or more generator due to protection or equipment issues will need to be communicated by the GO or GOP to the BA for consideration in reserve calculation.</p> <p>(9) Many of the changes to the TOP standard are modifying or adding parallel requirements that the Real-Time Operations standards drafting team has already proposed for removal. This project needs to be coordinated with the Real-Time Operations project to assess the need for these additions/modifications.</p> <p>(10) VAR-001 R8 modifications are not necessary because the TOP is already required to operate reactive generation scheduling. They can't do this without considering the Generator Interconnection Facility.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
Bonneville Power Administration	Yes	
Competitive Power Ventures, Inc.	Yes	

**Consideration of Comments on Generator Requirements at the Transmission Interface — Project 2010-07**

Organization	Yes or No	Question 5 Comment
Detroit Edison Company	Yes	
El Dorado Energy LLC	Yes	
Electric Market Policy	Yes	
Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners	Yes	
First Wind	Yes	
Ingleside Cogeneration, LP	Yes	
Kansas City Power & Light	Yes	
Mesquite Power	Yes	
PSEG Companies	Yes	
Sempra Generation	Yes	
SERC Planning Standards Subcommittee	Yes	

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Organization	Yes or No	Question 5 Comment
South Carolina Electric and Gas	Yes	
Southern California Edison co.	Yes	Additional clarification would be useful as it/ they would cut down on future requests for interpretation
<b>Response:</b> The SAR DT thanks you for your comment.		
American Electric Power	Yes	AEP feels that a majority of the standards that were modified add clarity. We reserve the right to comment when the Standard Drafting Team posts the draft Standard(s).
<b>Response:</b> The SAR DT thanks you for your comment. There will be additional opportunities to comment on the specific proposed modifications when the project progresses to standard drafting.		
Public Utility District #1 of Clark County	Yes	Except as discussed in comments 2, 3, and 4, Clark is in agreement with the proposed changes.
<b>Response:</b> The SAR DT thanks you for your comment.		
American Transmission Company	Yes	<p>For FAC-009 [Establish and Communicate Facility Ratings], we believe that the additional wording to highlight that the term “Facilities” includes “Generation Interconnection Facilities” is superfluous, and therefore, it should not be added. The proposed new and revised definitions provide more than enough clarity</p> <p>For MOD-010 [Steady State Data for System Modeling], we believe that the additional wording of “for plant and Generator Interconnection Facilities” is superfluous, and therefore, it should not be added. The proposed new and revised definitions provide more than enough clarity.</p> <p>For MOD-012 [Dynamic System Data for System Modeling], we believe that the additional wording of “for plant and Generator Interconnection Facilities” is superfluous, and therefore, it should not be added. The proposed new and revised definitions provide more than enough clarity.</p>
<b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT.		
Entegra Power	Yes	SEE COMMENTS FOR QUESTION 2.

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Organization	Yes or No	Question 5 Comment
Group LLC		
<p><b>Response:</b> The SAR DT thanks you for your comment. Please see the response to your comments on Question 2.</p>		
Manitoba Hydro	Yes	The modifications at this point appear appropriate.
<p><b>Response:</b> The SAR DT thanks you for your comment.</p>		
Pepco Holdings, Inc - Affiliates	Yes	<p>There should be a clause that the TO shall be responsible for FAC-003 activities inside the TO's substation regardless of ownership of the Generation Interconnection Facility so we don't have to coordinate entry, etc. and they will likely have this handled for the bulk of their property anyway. R3 quarterly reporting of outage caused by vegetation is excessive for GOs. GOs would probably survey and cut as needed their Right of Ways at least once a year and probably already do so. TOs probably perform vegetation management on a multi-year cycle, so they might need to note quarterly if there is a veg. incident that occurs one or two quarters before the next round of survey/management on that line.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT. There were many suggestions for additional or alternate modifications to FAC-003 and these suggestions will be addressed by the SDT.</p>		

**6. Do you believe there are any other Transmission Owner or Transmission Operator standards or requirements that should be applicable to the Generator Owner or Generator Operator other than those identified?**

**Summary Consideration:** Stakeholders did not indicate the need to include any requirements or standards that were not already contained in the SAR. However, based on discussions with FERC and NERC staffs regarding previous Commission actions and NERC compliance filings, the SAR DT modified the SAR to give the SDT the flexibility to consider further modifications not identified in the Ad Hoc Report.

Organization	Yes or No	Question 6 Comment
AmerenUE, Power Operations Services	No	
American Transmission Company	No	
Bonneville Power Administration	No	
California ISO	No	
Competitive Power Ventures, Inc.	No	
Constellation Power Source Generation Inc.	No	
Detroit Edison Company	No	
E.ON U.S.	No	
El Dorado Energy LLC	No	
Electric Market Policy	No	
Energy Standards Working Group	No	



**Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07**

Organization	Yes or No	Question 6 Comment
Entegra Power Group LLC	No	
Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners	No	
First Wind	No	
Florida Municipal Power Agency	No	
Independent Electricity System Operator	No	
Ingleside Cogeneration, LP	No	
ISO RTO Council Standards Review Committee	No	
Luminant	No	
Mesquite Power	No	
Midwest ISO Standards Collaborators	No	
North Carolina Electric Membership Corporation	No	
Pepco Holdings, Inc - Affiliates	No	
Prairie Power, Inc.	No	
PSEG Companies	No	

**Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07**

Organization	Yes or No	Question 6 Comment
Public Utility District #1 of Clark County	No	
Sempra Generation	No	
SERC Planning Standards Subcommittee	No	
South Carolina Electric and Gas	No	
Tenaska, Inc.	No	
American Electric Power	No	At this point in time, AEP cannot identify any other TO/TOP requirements that should be considered.
<b>Response:</b> The SAR DT thanks you for your comment.		
Southern California Edison co.	No	Do not feel that this question is in the scope of Project 2010-07 as written
<b>Response:</b> The SAR DT thanks you for your comment.		
Duke Energy	No	However the SDT should perform a complete review.
<b>Response:</b> The SAR DT thanks you for your comment. The SDT will review all applicable standards changes as needed and required by the scope and purpose of the SAR.		
Manitoba Hydro	No	No manpower available at this time to examine all possibilities and scenarios.
<b>Response:</b> The SAR DT thanks you for your comment.		
Kansas City Power & Light	No	Not at this time.
<b>Response:</b> The SAR DT thanks you for your comment.		

**7. The next posting of the proposed revisions to these standards will include conforming changes to the measures and compliance elements, and will include an implementation plan. Please identify how much time you feel an entity will need to become fully compliant with the following new/ revised requirements:**

The Generator Operator who has responsibility for monitoring the status of a special protection system or remedial action scheme at the generating facility for the benefit of Bulk Electric System reliability should notify the Transmission Operator when a change in status or capability occurs. (IRO-005)

**Summary Consideration:** The SAR DT thanks all stakeholders for their response to this question and its subcomponents. This series of questions was meant to provide input for the SDT in development of the required implementation plan that will accompany this project as it moves forward. The SAR DT would like to note that the three challenges most cited were training, agreements, and technical details. This information will be referred to the SDT for their consideration.

Organization	Time	Question 7 Comment
Pepco Holdings, Inc - Affiliates		No SPS currently in system.
<b>Response:</b> The SAR DT thanks you for your comment.		
California ISO		<p>We are not a GOP and hence we are unable to comment on this and other questions addressing the GOP compliance. However, the CAISO has the following comments on the effort required for other aspects of this Project:</p> <ul style="list-style-type: none"> <li>o As discussed under the answer to Question 5 above, it is not clear if the proposed changes to PRC-001 will require the Balancing Authority (BA) to understand the purpose and limitations of protection schemes associated with all of the Generator Interconnection Facilities in its area, even if such facilities are not under the control of the BA. If this is the case, significant and time-consuming effort will be required to identify the technical details of all of the Generator Interconnection Facilities in the BA and develop a training program to train applicable personnel on them. This is estimated to require up to 24 months.</li> <li>o If the proposed changes are approved they will affect 16 Standards affecting CAISO registrations. Most, if not all, of these changes will require modifications to the Reliability Standards Agreements (RSAs) between the CAISO and its Participating Transmission Operators to reflect the new wording and any delegated tasks. This may require 12 to 24 months to implement.</li> </ul>
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		

**Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07**

Organization	Time	Question 7 Comment
Constellation Power Source Generation Inc.	1 year	
Energy Standards Working Group	1 year	
Tenaska, Inc.	1 year	
Bonneville Power Administration	1 year, if agreements need to be renegotiated.	
North Carolina Electric Membership Corporation	12 months	
SERC Planning Standards Subcommittee	12 months	
Kansas City Power & Light	12 months	Basically this is a training issue. It takes time to prepare the training materials and to train all Generator Operators considering shift schedules and to implement the training as part of an ongoing process.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Prairie Power, Inc.	12 months following Regulatory Approval	
Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners	18 months	
Luminant	18 months	

**Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07**

Organization	Time	Question 7 Comment
South Carolina Electric and Gas	18 months	
Electric Market Policy	18 months to two years	We feel that, in most cases, such monitoring will only require RTU connectivity of the data points as well as incorporation into GOP control room displays.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Southern California Edison co.	3yrs	Pls refer to question No. 8
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Duke Energy	Approximately 3 months.	Depends upon measures and data requirements, but would probably be a short period of time.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
First Wind	Immediately unless status requires change to additional requirements which might be 18 months to two years)	The Generator Interconnection Facilities are already considered to be part of our Generator Plant and therefore have already been included in our existing compliance program.
<b>Response:</b> The SAR DT thanks you for your comment.		
Entegra Power Group LLC	NO COMMENT	
Public Utility District #1 of Clark County	No time	Clark has no SPS or RAS for which it is responsible.
<b>Response:</b> The SAR DT thanks you for your comment.		

**Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07**

Organization	Time	Question 7 Comment
Florida Municipal Power Agency	The amount of time it takes to compile documentation to fulfill the data retention requirements of the requirement	For most of these new requirements, the Entities are most likely fulfilling the requirements, but, may be missing the documentation to prove that they are doing so. So, to be auditably (“fully”) compliant, the Entities will need the amount of time it takes to build up sufficient evidence of compliance. This may only be a month to develop documentation, to a longer period of time to prove periodicity (e.g., a PRC-005 type of requirement - not PRC-005 itself - but a requirement that may need to be done periodically such as training to show that it is done periodically.
<p><b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.</p>		

- a. Each Generator Operator shall provide its operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Generation Facility and the Generation Interconnection Facility, and to implement directives of the Transmission Operator and Balancing Authority. (PER-001)

**Summary Consideration:** The SAR DT thanks all stakeholders for their response to this question and its subcomponents. This series of questions was meant to provide input for the SDT in development of the required implementation plan that will accompany this project as it moves forward. The SAR DT would like to note that the three challenges most cited were training, agreements, and technical details. This information will be referred to the SDT for their consideration.

Organization	Time	Question 7a Comment
American Electric Power		AEP believes that this requirement is not needed and should be out of the scope for this SAR.
<b>Response:</b> The SAR DT thanks you for your comment. These comments will be referred to the SDT.		
Pepco Holdings, Inc - Affiliates		These responsibilities and authorities are already in place for other standards.
<b>Response:</b> The SAR DT thanks you for your comment. These comments will be referred to the SDT.		
Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners	12 months	
North Carolina Electric Membership Corporation	12 months	
SERC Planning Standards Subcommittee	12 months	
South Carolina Electric and Gas	12 months	
Prairie Power, Inc.	12 months following	

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Organization	Time	Question 7a Comment
	Regulatory Approval	
Luminant	18 months	
Energy Standards Working Group	2 years	
Tenaska, Inc.	2 years	
Constellation Power Source Generation Inc.	2 years	Time is needed for training and terminology to percolate throughout the Generation Facility and that it be ingrained with the Operators.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Southern California Edison co.	3yrs	Pls refer to question No. 8
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Bonneville Power Administration	6 months	
Duke Energy	Approximately 24 months.	Multiple shifts and multiple facilities will require time to get training developed and delivered.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
First Wind	Less than 1 year	Memo from management should suffice.
Electric Market Policy	Less than one year	Memo from management should suffice.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Kansas City Power & Light	N/A	The Generator Operator should be operating equipment within the Generator Interconnection Facility at the



**Consideration of Comments on Generator Requirements at the Transmission Interface — Project 2010-07**

Organization	Time	Question 7a Comment
		direction of the Transmission Operator.
<b>Response:</b> The SAR DT thanks you for your comment. We will refer these comments to the SDT.		
Entegra Power Group LLC	NO COMMENT	
Public Utility District #1 of Clark County	No Time.	Clark’s Generator Operator personnel have responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Generation Facility and the Generation Interconnection Facility, and to implement directives of the Transmission Operator and Balancing Authority.
<b>Response:</b> The SAR DT thanks you for your comment.		
Florida Municipal Power Agency	See above	See above
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		

- b. Each Generator Operator shall implement an initial and continuing training program for all personnel responsible for operating the Generator Interconnection Facility to ensure the ability to operate the equipment in a reliable manner. (Per-002)

**Summary Consideration:** The SAR DT thanks all stakeholders for their response to this question. This series of questions was meant to provide input for the SDT in development of the required implementation plan that will accompany this project as it moves forward. The SAR DT would like to note that the three challenges most cited were training, agreements, and technical details. This information will be referred to the SDT for their consideration. The time needed to comply varied from 0-3 years.

Organization	Time	Question 7b Comment
E.ON U.S.		A training program for this would need to be created, procedures approved, implemented, and instituted at all power plants for all shifts. E.ON U.S. recommends that the addition of PER-002 R3 be coordinated with the existing standard PRC-001 R1, to eliminate redundancy.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
American Electric Power		AEP believes that this requirement is not needed and should be out of the scope for this SAR.
<b>Response:</b> The SAR DT thanks you for your comment. We will refer these comments to the SDT.		
Pepco Holdings, Inc - Affiliates	0-2 years	Currently establish training based on the RTO requirements. It would be Conectiv's policy to continue this training for this requirement. If other training is imposed upon the Entities, it may require up to two years to develop and initiate full training.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Entegra Power Group LLC	1 YEAR	
Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners	12 months	
North Carolina Electric	12 months	

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Organization	Time	Question 7b Comment
Membership Corporation		
SERC Planning Standards Subcommittee	12 months	
South Carolina Electric and Gas	12 months	
Energy Standards Working Group	2 years	
Tenaska, Inc.	2 years	
First Wind	2 years	Developing the training and providing it while accommodating shift employees will require a substantial amount of time.
<p><b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.</p>		
Constellation Power Source Generation Inc.	2 years	Time is needed to implement a training plan and revise it based on feedback from those being trained.
<p><b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.</p>		
Bonneville Power Administration	2-3 years, depending on the extent of equipment involved and size of facility.	
Luminant	24 months	
Prairie Power, Inc.	24 months following Regulatory Approval	

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Organization	Time	Question 7b Comment
Southern California Edison co.	3yrs	Pls refer to question No. 8
<b>Response:</b> The SAR DT thanks you for your comment.		
Duke Energy	Approximately 24 months.	Multiple shifts and multiple facilities will require time to get training developed and delivered.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Kansas City Power & Light	N/A	The Generator Operator should be operating equipment within the Generator Interconnection Facility at the direction of the Transmission Operator.
<b>Response:</b> The SAR DT thanks you for your comment. We will refer these comments to the SDT.		
Florida Municipal Power Agency	See above	See above
<b>Response:</b> The SAR DT thanks you for your comment.		
Public Utility District #1 of Clark County	Twelve months.	Clark’s generating operating personnel regularly engage in training however, to implement a Training Program as rigorous as the TOP Training Program will take some time to complete.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Electric Market Policy	two years	Developing the training and providing it while accommodating shift employees will require a substantial amount of time.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		

**c. The Generator Operator shall coordinate the operation of its Generator Interconnection Facility with the Transmission Operator to whom it interconnects to preserve Interconnection reliability. (TOP-001)**

**Summary Consideration:** The SAR DT thanks all stakeholders for their response to this question. This series of questions was meant to provide input for the SDT in development of the required implementation plan that will accompany this project as it moves forward. The SAR DT would like to note that the three challenges most cited were training, agreements, and technical details. This information will be referred to the SDT for their consideration. The time needed to comply varied from 0-3 years.

Organization	Time	Question 7c Comment
E.ON U.S.		Appears redundant with point e) below. There are already generator-outage reporting protocols in place. This would be an unnecessary addition to existing processes.
<b>Response:</b> The SAR DT thanks you for your comment.		
Pepco Holdings, Inc - Affiliates	0-2 years	Entity currently coordinates this operation with the TOP. If additional requirements are instituted by NERC, there may be a need to have time to develop new programs and policies to comply with additional requirements.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Constellation Power Source Generation Inc.	1 year	
Energy Standards Working Group	1 year	
Tenaska, Inc.	1 year	
Bonneville Power Administration	1 year, if agreements need to be renegotiated.	

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Organization	Time	Question 7c Comment
Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners	12 months	
North Carolina Electric Membership Corporation	12 months	
SERC Planning Standards Subcommittee	12 months	
Luminant	18 months	
South Carolina Electric and Gas	18 months	
Prairie Power, Inc.	24 months following Regulatory Approval	
Southern California Edison co.	3yrs	Pls refer to question No. 8
<b>Response:</b> The SAR DT thanks you for your comment.		
Kansas City Power & Light	6 months	If this is not already going on, this should not take long to implement.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Duke Energy	Approximately 3 months.	Depends upon measures and data requirements, but should be a short period of time.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
First Wind	Less than 1 year	There is already generator outage reporting protocols in place. This is just an addition to existing processes. Additionally, the Generator Interconnection Facility is already considered to be part of the Generating Facility and is likely already part of our existing compliance program.

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Organization	Time	Question 7c Comment
<b>Response:</b> The SAR DT thanks you for your comment.		
Electric Market Policy	Less than one year	There is already generator outage reporting protocols in place. This is just an addition to existing processes.
<b>Response:</b> The SAR DT thanks you for your comment.		
Entegra Power Group LLC	NO COMMENT	
Public Utility District #1 of Clark County	No Time.	Clark believes the operation of its generator is already under the direction of its TOP and that coordination has already occurred since the TOP has included the operation of Clark’s generator in its TOP-002 Normal Operations Plan.
<b>Response:</b> The SAR DT thanks you for your comment.		
Florida Municipal Power Agency	See above	See above

**d. The Transmission Operator has decision-making authority for the Generator Interconnection Operational Interface. (TOP-001)**

**Summary Consideration:** The SAR DT thanks all stakeholders for their response to this question. This series of questions was meant to provide input for the SDT in development of the required implementation plan that will accompany this project as it moves forward. The SAR DT would like to note that the three challenges most cited were training, agreements, and technical details. This information will be referred to the SDT for their consideration. The time needed to comply varied from 0-3 years.

Organization	Time	Question 7d Comment
Pepco Holdings, Inc - Affiliates	0-2 years	Coordination is required for the TOP to notify the GO/GOP of the decisions being implemented.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Constellation Power Source Generation Inc.	1 year	
Energy Standards Working Group	1 year	
Tenaska, Inc.	1 year	
Bonneville Power Administration	1 year, if agreements need to be renegotiated.	
Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners	12 months	
North Carolina Electric Membership Corporation	12 months	



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Organization	Time	Question 7d Comment
SERC Planning Standards Subcommittee	12 months	
Prairie Power, Inc.	12 months following Regulatory Approval	
Luminant	18 months	
South Carolina Electric and Gas	18 months	
Southern California Edison co.	3yrs	Pls refer to question No. 8
<b>Response:</b> The SAR DT thanks you for your comment. Please see the response to question 8.		
Kansas City Power & Light	6 months	If this is not already going on, this should not take long to implement.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Duke Energy	Approximately 3 months	Depends upon measures and data requirements, but should be a short period of time.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
First Wind	less than 1 year	Expect that, in most cases, the Interconnection Agreement between the generator and the TO or DP that it connects with already contains language that supports this because the Generator Interconnection Facility is already considered to be part of the Generating Facility.
<b>Response:</b> The SAR DT thanks you for your comment.		
Electric Market Policy	Less than one year	Expect that, in most cases, the Interconnection Agreement between the generator and the TO or DP that it connects with already contains language that supports this.
<b>Response:</b> The SAR DT thanks you for your comment.		

**Consideration of Comments on Generator Requirements at the Transmission Interface — Project 2010-07**

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Organization	Time	Question 7d Comment
Entegra Power Group LLC	NO COMMENT	
Public Utility District #1 of Clark County	No time.	Clark believes that existing standards already grant the TOP decision-making authority for the Generator Interconnection Operational Interface.
<b>Response:</b> The SAR DT thanks you for your comment.		
Florida Municipal Power Agency	See above	See above
<b>Response:</b> The SAR DT thanks you for your comment.		

**e. The Generator Operator shall notify the Transmission Operator of a change in status of the Generation Interconnection Facility.**

**Summary Consideration:** The SAR DT thanks all stakeholders for their response to this question. This series of questions was meant to provide input for the SDT in development of the required implementation plan that will accompany this project as it moves forward. The SAR DT would like to note that the three challenges most cited were training, agreements, and technical details. This information will be referred to the SDT for their consideration. The time needed to comply varied from 0-3 years.

Organization	Time	Question 7e Comment
Pepco Holdings, Inc - Affiliates	0-2 years	Entity currently coordinates this operation with the TOP. If additional requirements are instituted by NERC, there may be a need to have time to develop new programs and policies to comply with additional requirements.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Constellation Power Source Generation Inc.	1 year	
Energy Standards Working Group	1 year	
Tenaska, Inc.	1 year	
North Carolina Electric Membership Corporation	12 months	
SERC Planning Standards Subcommittee	12 months	
South Carolina Electric and Gas	12 months	
Prairie Power, Inc.	12 months following Regulatory Approval	

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Organization	Time	Question 7e Comment
Luminant	18 months	
Southern California Edison co.	3yrs	Pls refer to question No. 8
<b>Response:</b> The SAR DT thanks you for your comment.		
Kansas City Power & Light	6 months	If this is not already going on, this should not take long to implement.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Bonneville Power Administration	6 months.	
Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners	8 months	
Duke Energy	Approximately 3 months	Depends upon measures and data requirements, but should be a short period of time.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
First Wind	less than 1 year	Expect that, in most cases, the Interconnection Agreement between the generator and the TO or DP that it connects with already contains language that supports this.
<b>Response:</b> The SAR DT thanks you for your comment.		
Electric Market Policy	Less than one year	Expect that, in most cases, the Interconnection Agreement between the generator and the TO or DP that it connects with already contains language that supports this.
<b>Response:</b> The SAR DT thanks you for your comment.		
Entegra Power Group LLC	NO COMMENT	

**Consideration of Comments on Generator Requirements at the Transmission Interface — Project 2010-07**

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Organization	Time	Question 7e Comment
Public Utility District #1 of Clark County	No time.	Clark’s Generation Interconnection Facility status is already provided to the TOP in real time over the TOP’s SCADA system.
<b>Response:</b> The SAR DT thanks you for your comment.		
Florida Municipal Power Agency	See above	See above
<b>Response:</b> The SAR DT thanks you for your comment.		

f. The Generator Operator shall operate the Generation Interconnection Facility within Facility Ratings. (TOP-004)

**Summary Consideration:** The SAR DT thanks all stakeholders for their response to this question. This series of questions was meant to provide input for the SDT in development of the required implementation plan that will accompany this project as it moves forward. The SAR DT would like to note that the three challenges most cited were training, agreements, and technical details. This information will be referred to the SDT for their consideration. The time needed to comply varied from 0-3 years.

Organization	Time	Question 7f Comment
American Electric Power		AEP does not believe that the added requirement is necessary as the Generator Interconnection Facility should be adequately sized to handle the output of the generator.
<b>Response:</b> The SAR DT thanks you for your comment. Based on a review of the full body of industry comments, we believe that the standards actions proposed in this SAR are appropriate. Specific modifications will be determined by the SDT.		
Bonneville Power Administration	0 months.	
Pepco Holdings, Inc - Affiliates	0-2 years	Entity currently operates within the facility ratings as required under FAC. If additional requirements are instituted by NERC, there may be a need to have time to develop new programs and policies to comply with additional requirements
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Constellation Power Source Generation Inc.	1 year	
Energy Standards Working Group	1 year	
Tenaska, Inc.	1 year	
North Carolina Electric Membership Corporation	12 months	
SERC Planning Standards	12 months	

**Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07**

Organization	Time	Question 7f Comment
Subcommittee		
Prairie Power, Inc.	12 months following Regulatory Approval	
Luminant	18 months	
South Carolina Electric and Gas	18 months	
Southern California Edison co.	3yrs	Pls refer to question No. 8
<b>Response:</b> The SAR DT thanks you for your comment.		
Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners	6 months	
Kansas City Power & Light	6 months	If this is not already going on, this should not take long to implement.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Duke Energy	Approximately 3 months.	Depends upon measures and data requirements, but should be a short period of time.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
First Wind	less than 1 year	The Generator Interconnection Facility is already considered to be part of the Generator Unit and the facility should be compliant currently with FAC standards.
<b>Response:</b> The SAR DT thanks you for your comment.		
Electric Market Policy	less than one year	Facility should be compliant currently with FAC standards.

**Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07**

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Organization	Time	Question 7f Comment
<b>Response:</b> The SAR DT thanks you for your comment.		
Entegra Power Group LLC	NO COMMENT	
Public Utility District #1 of Clark County	No time.	The Generation Interconnection Facilities of Clark have ratings that exceed the maximum generating capability of the interconnected generation facility.
<b>Response:</b> The SAR DT thanks you for your comment.		
Florida Municipal Power Agency	See above	See above
<b>Response:</b> The SAR DT thanks you for your comment.		



**g. The Generator Operator shall disconnect the Generation Interconnection Facility immediately in coordination with the Transmission Operator when time permits or as soon as practical thereafter if an overload or other abnormal condition threatens equipment or personnel safety. (TOP-008)**

**Summary Consideration:** The SAR DT thanks all stakeholders for their response to this question. This series of questions was meant to provide input for the SDT in development of the required implementation plan that will accompany this project as it moves forward. The SAR DT would like to note that the three challenges most cited were training, agreements, and technical details. This information will be referred to the SDT for their consideration. The time needed to comply varied from 0-3 years.

Organization	Time	Question 7g Comment
E.ON U.S.		In case of overload, the E.ON U.S. GOP has an overload current relay that already removes a generating unit from the grid immediately. Moreover, it is expected that in most cases an Interconnection Agreement between the generator and TO that it connects with already contains language supportive of this.
<b>Response:</b> The SAR DT thanks you for your comment.		
Pepco Holdings, Inc - Affiliates	0-2 years	Entity currently coordinates this operation with the TOP. If additional requirements are instituted by NERC, there may be a need to have time to develop new programs and policies to comply with additional requirements.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Constellation Power Source Generation Inc.	1 year	
Energy Standards Working Group	1 year	
Tenaska, Inc.	1 year	
Bonneville Power Administration	1 year, if agreements need to be renegotiated.	

**Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07**

Organization	Time	Question 7g Comment
Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners	12 months	
North Carolina Electric Membership Corporation	12 months	
SERC Planning Standards Subcommittee	12 months	
South Carolina Electric and Gas	12 months	
Prairie Power, Inc.	12 months following Regulatory Approval	
Luminant	36 months	
Southern California Edison co.	3yrs	Pls refer to question No. 8
<b>Response:</b> The SAR DT thanks you for your comment.		
Kansas City Power & Light	6 months	If this is not already going on, this should not take long to implement.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Duke Energy	Approximately 3 months.	Depends upon measures and data requirements, but should be a short period of time.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
First Wind	less than 1 year	The Generator Interconnection Facility is already considered to be part of the Generator Unit. Expect that, in most cases, the Interconnection Agreement between the generator and the TO or DP that it connects with already contains language that supports this.

**Consideration of Comments on Generator Requirements at the Transmission Interface — Project 2010-07**

Organization	Time	Question 7g Comment
<b>Response:</b> The SAR DT thanks you for your comment.		
Electric Market Policy	less than one year	Expect that, in most cases, the Interconnection Agreement between the generator and the TO or DP that it connects with already contains language that supports this.
<b>Response:</b> The SAR DT thanks you for your comment.		
Entegra Power Group LLC	NO COMMENT	
Public Utility District #1 of Clark County	No time.	Clark has experienced no operating conditions where it had to disconnect the Generation Interconnection Facility immediately due to an overload or other abnormal condition that threatened equipment or personnel safety.
<b>Response:</b> The SAR DT thanks you for your comment.		
Florida Municipal Power Agency	See above	See above
<b>Response:</b> The SAR DT thanks you for your comment.		

**8. If you have any other comments on this SAR or proposed standard revisions and NERC Glossary modifications that you have not already provided in response to the prior questions, please provide them here.**

**Summary Consideration:** The SAR DT thanks all stakeholders for their response to this question. Many of the comments were addressed in earlier responses. Based on discussions with FERC and NERC staffs regarding previous Commission actions and NERC compliance filings, the SAR DT modified the SAR to give the SDT the flexibility to consider further modifications not identified in the Ad Hoc Report. Finally, revisions to the SAR also allow the SDT the option of merging the changes into one new standard or into several different existing standards.

Organization	Question 8 Comment
<p>Constellation Power Source Generation Inc.</p>	<p>Constellation would like to thank the Ad-Hoc group for the excellent work they did in creating the GOTO Final Report. In particular, here are a few excerpts that Constellation agrees with, and would like the future SDT to consider:</p> <ul style="list-style-type: none"> <li>oThe Generator Owner or Generator Operator that owns and/or operates a Generator Interconnection Facility, that is, a sole-use facility that interconnects the generator to the grid, should not be registered as a Transmission Owner or Transmission Operator by virtue of owning or operating its Generator Interconnection Facility.</li> <li>oA Generator Interconnection Facility is considered as though part of the generating facility specifically for purposes of applying Reliability Standards to a Generator Owner or Generator Operator.</li> <li>oAfter review of the existing Transmission Operator requirements that are not currently applicable to Generator Operators, no existing Transmission Operator requirements should apply to Generator Operators as a result of the Generator Interconnection Facility.</li> </ul>
<p><b>Response:</b> The SAR DT thanks you for your comments. The SAR DT supports the three concepts identified.</p>	
<p>EI Dorado Energy LLC</p>	<p>EI Dorado Energy commends the efforts of the NERC Ad Hoc Group, and supports the Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface, and Standards Authorization Request addressing the various Standards containing GO/GOP and TO/TOP Requirements. The Final Report and SARs are products of detailed analysis and thoughtful consideration of the myriad issues surrounding the reliability implications of ownership and operation of Generator Interconnection Facilities. It is noteworthy - though hardly surprising - that, after many months of study, the GO/TO Task Force, a balanced group comprised of members from a broad spectrum of functional categories, concluded that only modest changes to the Reliability Standards would be required in order to ensure that generator interconnection facilities are operated reliably. When implemented, the recommendations included in the Final Report and SARs should go a long way toward providing the regulatory and compliance certainty needed by generators who own or operate Generator Interconnection Facilities. Accordingly, EI Dorado Energy encourages the Standards Drafting Team to act quickly to implement the SARs.</p>

Organization	Question 8 Comment
<p><b>Response:</b> The SAR DT thanks you for your comment.</p>	
<p>Competitive Power Ventures, Inc.</p>	<p>Every effort should be made to precisely describe requirements that directly correspond to, and address, the reliability issues framed by the GO/TO Ad Hoc Group. Particularly, "interconnection facilities" should be defined to account for and exclude various transmission configurations on the generator side of the interconnection point that do not create network power flows or otherwise operate as bona fide transmission systems.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT.</p>	
<p>Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners</p>	<p>FAC-003 - Applicability apply to GIF above 200 kV that exceed two spans should be revised to "less than one-half mile" as span lengths vary considerably. For example we have 3 spans over 1/4 mile. R1. requirement to "keep current, a formal TVMP" should allow latitude for those entities with one-quarter mile of radial connecting transmission, all visible from the office window, to have a less than a formal program, or at least a very SIMPLE program.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT.</p>	
<p>First Wind</p>	<p>FAC-003 - Step 4.5 should be clearly identified as a “qualifier” for Generator Owner applicability. Although not the intent of the standard, as currently drafted, the requirements apply to all Generator Owners. Additionally we recommend modifications to address a disqualifier if the plant is located in an environment whose natural environment would prevent vegetation from growing that could interfere with the reliability of the bulk Electric System. The following changes are recommended.</p> <p>4.4. Generator Owner.</p> <p>4.5. This standard shall apply to the Generator Interconnection Facility above 200 kV that exceed two spans from the generator property line or are otherwise deemed critical by the Regional Entity below 200 kV (subject to the two-span criteria.). This standard does not apply to all Generator Interconnection Facilities outside this threshold and those facilities located in an area whose environment would prevent vegetation from growing. A generating facility located underground, in the high desert or within a fully developed urban area where vegetation disturbances could not occur should not be required to have a vegetation management program.</p> <ul style="list-style-type: none"> <li>o MOD-010 - The changes made in this standard are not reflected in the associated standard, MOD-011 (possibly because MOD-011 is not FERC approved).</li> <li>o MOD-012 - The changes made in this standard are not reflected in the associated standard, MOD-013 (possibly because MOD-013 is not FERC approved).</li> <li>o PER-001 - The Purpose statement in the Standard needs to be modified to include GOP.</li> </ul>

Organization	Question 8 Comment
	<p>o PER-002 - The Purpose statement in the Standard needs to be modified to include GOP. We recommend the addition of PER-002 R3 is coordinated with the existing standard PRC-001 R1 to eliminate redundancy. While PER-002 R3 more clearly calls for training, PRC-001 R1 implies training. The two standards should be combined into one training requirement. PRC-001 R1 "Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area." We recommend retiring PRC-001 R1 and modifying the proposed standard PER-002 R3 as shown below:</p> <p style="padding-left: 40px;">Each Generator Operator shall implement an initial and continuing training program for all operating personnel that are responsible for operating the Generator Protection System Equipment, including the Generator Interconnection Facility that verifies the personnel's ability and understanding to operate the equipment in a reliable manner.</p> <p>o TOP-002 - Requirement R14 contains sub-requirements R14.1 and R14.2 that were retired August, 1, 2007. Suggest deleting the retired requirements with the proposed revision.</p> <p>o TOP-004 - Requirement R7 has been added for the Generator Operator; however, the Generator Operation has not been added to the Applicability.</p> <p>o TOP-008 - The Purpose statement in the Standard needs to be modified to include GOP.</p>
<p><b>Response:</b> The SAR DT thanks you for your comments. They will be referred to the SDT.</p>	
California ISO	<p>It does not appear that any of the Measures in the proposed Standards have been revised to reflect the new and/or revised requirements.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. The intent was to post just the initial set of proposed requirements to provide stakeholders with a sense of the scope of the project. The SDT assigned to this project will need to work with stakeholders to develop not only the requirements, but all the other elements needed to support those requirements, including measures, violation risk factors, time horizons, violation severity levels, evidence retention, etc.</p>	
North Carolina Electric Membership Corporation	<p>NC EMC is concerned with the decision to use "revisions to the latest versions of the following standards" that were included in red-line format in this SAR: o BAL-005 o CIP-002 o EOP-001, -003, -004, -008 o FAC-001, -003, -008, -009 o IRO-005 o MOD-010, -012 o PER-001, -002 o PRC-001, -004, -005 o TOP-001, -002, -003, -004, -008 o VAR-001, -002</p> <p>The use of these versions of the standards, many of which have been revised, approved by the NERC Board of Trustees and filed with FERC emphasizes the flaw in a regulatory approval process that is not uniform throughout North America. Not all registered entities are FERC jurisdictional, therefore, are already required to comply with Reliability Standards upon NERC Board of Trustees approval. Of the standards that are included in this SAR, three projects not including interpretations have been retired, modified, or new standards created that are now complied with by some registered entities. The projects include; Project 2006-01 "System Personnel Training" PER-002, PER-004, and PER-005, Pre-2006 "Operate Within Interconnection Reliability Operating Limits" IRO-007 through IRO-010 and Project 2008-06 "Cyber Security" Order</p>

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Organization	Question 8 Comment
	<p>706 – CIP-002 through CIP-009. In addition, it is difficult to determine whether there is any coordination between the activities of this SAR drafting team and those of the many existing drafting teams that are also revising standards. NCEMC understands the dilemma of how to revise standards in a regulatory environment that has no defined time-line guidelines for approval of standards upon filing with FERC, but reminds NERC, the Standards Committee and drafting teams that the process must address the varying regulatory approval processes in North America.</p>
<p><b>Response:</b> The SAR DT thanks you for your comments. They will be referred to the SDT. The SDT will work with the latest BOT approved versions of the standards in support of your comment.</p>	
SERC Planning Standards Subcommittee	No other comments
Kansas City Power & Light	No other comments.
South Carolina Electric and Gas	none
National Rural Electric Cooperative Association (NRECA)	<p>NRECA is concerned with the decision to use “revisions to the latest versions of the following standards” that were included in red-line format in this SAR: o BAL-005 o CIP-002 o EOP-001, -003, -004, -008 o FAC-001, -003, -008, -009 o IRO-005 o MOD-010, -012 o PER-001, -002 o PRC-001, -004, -005 o TOP-001, -002, -003, -004, -008 o VAR-001, -002 The use of these versions of the standards, many of which have been revised, approved by the NERC Board of Trustees and filed with FERC emphasizes the flaw in a regulatory approval process that is not uniform throughout North America. Not all registered entities are FERC jurisdictional, therefore, are already required to comply with Reliability Standards upon NERC Board of Trustees approval. Of the standards that are included in this SAR, three projects not including interpretations have been retired, modified, or new standards created that are now complied with by some registered entities. The projects include; Project 2006-01 – System Personnel Training – PER-002, PER-004, and PER-005, Pre-2006 – Operate Within Interconnection Reliability Operating Limits – IRO-007 through IRO-010 and Project 2008-06 – Cyber Security – Order 706 – CIP-002 through CIP-009. In addition, it is difficult to determine whether there is any coordination between the activities of this SAR drafting team and those of the many existing drafting teams that are also revising standards. NRECA understands the dilemma of how to revise standards in a regulatory environment that has no defined time-line guidelines for approval of standards upon filing with FERC, but reminds NERC, the Standards Committee and drafting teams that the process must address the varying regulatory approval processes in North America.</p>
<p><b>Response:</b> The SAR DT thanks you for your comments. They will be referred to the SDT. The SDT will work with the latest BOT approved versions of the standards in support of your comment.</p>	
Electric Market Policy	oEOP-003 - I do not understand the addition of GOP to this standard. Additionally, the Purpose statement is not in

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Organization	Question 8 Comment
	<p>alignment with the additional GOP applicability.</p> <ul style="list-style-type: none"> <li>oFAC-003 - Step 4.5 should be clearly identified as a “qualifier” for Generator Owner applicability. Although not the intent of the standard, as currently drafted, the requirements apply to all Generator Owners.</li> <li>oMOD-010 - The changes made in this standard are not reflected in the associated standard, MOD-011 (possibly because MOD-011 is not FERC approved).</li> <li>oMOD-012 - The changes made in this standard are not reflected in the associated standard, MOD-013 (possibly because MOD-013 is not FERC approved).</li> <li>oPER-001 - The Purpose statement is not in alignment with the additional GOP applicability.</li> </ul>
<p><b>Response:</b> The SAR DT thanks you for your comments. They will be referred to the SDT.</p>	
American Electric Power	<p>Overall, AEP supports the concept of this SAR, but we question the number of new requirements that are being brought in scope. Some of the requirements added appear to encourage this SAR to reach farther than the scope of addressing the Generator Interconnection Facilities.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT. The intent of the SAR was to collect feedback on the proposed scope of this project.</p>	
Prairie Power, Inc.	<p>PPI contends this SAR and associated requirement additions and revisions go well beyond the recommendations from the Group needed to resolve the barrier issue between Transmission Operator and Generator Operator. The FAC-003 standard revision, so that vegetation management can be enforced for transmission lines which interconnect generators to transmission, is really all that is necessary. All these other changes just add confusion to already overlapped requirements.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT. One of the goals of this project is to eliminate ‘overlaps’ so there is a clear line of responsibility for each facility.</p>	
Southern California Edison co.	<p>SCE believes that implementing changes type of changes proposed in 2010-07 should be looked at as a whole/ one entire project rather than piece meal as alluded to in question number 7 of the comments form. As such, it is the company’s position that approximately 3yrs is right amount of time to reliably implement the proposed revisions to the suite of standards as identified in Project 2010-07. A 3 yr timeline would enable the project to be fully scoped out and budgeted, and allow for: completion of the necessary engineering studies; design, procurement and construction of any new facilities necessitated by the revisions; development of any new operations and communications procedures with respect to both the transmission and generation facilities; and the training of personnel related to any new procedures.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. The SAR has been modified to allow the SDT the option of merging the changes into one new standard or an</p>	



Organization	Question 8 Comment
	<p>existing standard(s). All timing issues related to the implementation plan will be addressed by the SDT. As envisioned, all requirements would become effective at the same time as the proposed definitions to ensure that there are no gaps in the body of NERC requirements.</p>
Sempra Generation	<p>Sempra Generation commends the efforts of the NERC Ad Hoc Group, and supports the Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface, and Standards Authorization Request addressing the various Standards containing GO/GOP and TO/TOP Requirements. The Final Report and SARs are products of detailed analysis and thoughtful consideration of the myriad issues surrounding the reliability implications of ownership and operation of Generator Interconnection Facilities. It is noteworthy - though hardly surprising - that, after many months of study, the GO/TO Task Force, a balanced group comprised of members from a broad spectrum of functional categories, concluded that only modest changes to the Reliability Standards would be required in order to ensure that generator interconnection facilities are operated reliably. When implemented, the recommendations included in the Final Report and SARs should go a long way toward providing the regulatory and compliance certainty needed by generators who own or operate Generator Interconnection Facilities. Accordingly, Sempra Generation encourages the Standards Drafting Team to act quickly to implement the SARs.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT.</p>	
AmerenUE, Power Operations Services	<p>The items in Question #7 illustrate the need for a written Agreement or Procedure between the GO, GOP, TO and TOP on how to comply with these new, and modified, Requirements. An Agreement or Procedure would provide the certainty of:</p> <ul style="list-style-type: none"> <li>o Assignable and measurable responsibilities,</li> <li>o Mutual agreement on specific actions, and</li> <li>o Implementation deadlines.</li> </ul> <p>Without such an Agreement or Procedure, there will be no auditable commitment to defined specific actions, predetermined responsibilities and closure of the reliability gap in total.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. The SDT will discuss these kinds of issues, but such agreements are covered by the NERC Rules of Procedures and it is outside the scope of both the SAR DT and the SDT to propose changes to the NERC Rules of Procedure.</p>	
ERCOT ISO	<p>The proposed language in Requirements 9 and 10 (hereafter R9 and R10) for NERC Standard TOP-001-X, Reliability Responsibilities and Authorities, clouds the responsibilities among different functional entities that are and are not held accountable to this Standard. Specifically, the first part of the sentence in R9 states: “The Generator Operator, in accord with the expectations defined by the Transmission Operator, shall coordinate...” This statement is overly broad and vague. For instance, is the statement meant to refer to Interconnection Agreements that have been entered into between Generator Operators and Transmission Operators? Or, is the statement intended to include other agreements as well? In addition, there</p>

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Organization	Question 8 Comment
	<p>are items listed in R9 (i.e., switching elements, outage planning, and real-time and anticipated emergency conditions) which are normally the responsibilities of the Transmission Owner and/or the Reliability Coordinator; however, NERC Standard TOP-001-X is not applicable to the Transmission Owner or the Reliability Coordinator. Also, the item “other conditions mutually agreed-upon by the Generator Operator and Transmission Operator” is vague and ambiguous and should be clarified in order not to confuse tasks that may be more aligned with the responsibilities of the Transmission Owner or the Reliability Coordinator. Furthermore, R9 and R10 strongly imply and explicitly give the Transmission Operator authority to take action “in order to preserve Interconnection reliability.” This type of wide-area authority is meant to describe Reliability Coordinator-related obligations. The NERC Function Reliability Model is clear in defining the function and tasks of reliability operations. The Reliability Coordinator is responsible, in concert with other Reliability Coordinators, for the Interconnection as a whole; not the Transmission Operator. Lastly, it is unclear how an entity registered for multiple functions (for example, Reliability Coordinator and Transmission Operator) would be held accountable under this NERC Standard. If the intent is that R9 and R10 are to be the obligations only of those functional entities for which the NERC Standard is applicable, then the language in the NERC Standard should clearly state that intent.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT. As envisioned, the SDT will coordinate its work with the Functional Model Working Group to ensure that any new functional entities are identified with a clear definition, and a clear scope of responsibilities and tasks.</p>	
PSEG Companies	<p>The PSEG Companies support this approach to ensure that all components of the BES are adequately covered by the reliability standards. The drafting team has done a good job of identifying the appropriate areas of concern.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment.</p>	
Transmission Owner/Generation Owner	<p>The SAR for Project 2010-07 proposes a number of specific changes to existing Reliability Standards based on the GOTO Report. FPL believes that identifying the exact standards and language for revision should be the purview of a Standards Drafting Team and not embedded within the SAR itself. The Standards Drafting Team should be empowered to review the GOTO Report and make independent recommendations. Many of the questions contained in this SAR comment form are more appropriate for a Standard's drafting comment form and not for a SAR. The place to discuss and evaluate specific wording changes as applicable to standards revisions should be contained in the Standard Drafting process. The SAR should lay the foundation for the need for changes, not disseminate or debate exact changes. FPL would recommend that the sections “Brief” and “Detailed Description” of the SAR should be amended as follows: “Taking into consideration the GOTO Final Report from November 2009, the need for revisions to existing standards may exist. The Standards Drafting Team will evaluate the recommendations of the GOTO Final Report and recommend changes as necessary.”</p>
<p><b>Response:</b> The SAR DT thanks you for your comment and agrees. The SAR DT has assembled the specific suggestions for revisions to definitions and requirements provided in response to this SAR. As envisioned, the SDT will consider those comments. Note that the SAR has been modified to give the SDT the flexibility to address this concern.</p>	

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Organization	Question 8 Comment
Northeast Power Coordinating Council	The term “two spans” is used in the Introductory Section of this Comment Form (Conclusions Item 6, Recommendations Item 3), and will need a clear, and specific definition. “Generally” is not a word to be used in a definition.
<b>Response:</b> The SAR DT thanks you for your comments.They will be referred to the SDT.	
Xcel Energy	There are many other standards development projects underway that are modifying the same standard. It is unclear as to how the changes will be coordinated amongst the many teams.
Xcel Energy	There are many other standards development projects underway that are modifying the same standard. It is unclear as to how the changes will be coordinated amongst the many teams.
<b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT. As envisioned, the SDT will work with the latest BOT approved versions of the standards and will coordinate its work with all other SDTs that are actively working on the same standards.	
ISO RTO Council Standards Review Committee	These SAR and associated draft standards changes go beyond what is needed to resolve the GO/TO GOP/TOP registration issue. The only real changes that are needed are to include adding GO and GOP applicability in the FAC-003 standard so that vegetation management can be enforced for lines built to interconnect generators without registering the GO/GOP as a TO/TOP. All additional changes just add confusion and cause significant coordination issues with other draft standard changes.This proposed SAR and associated standards’ modifications does not appear to have been coordinated with any other drafting team. There are many standards and requirements that are in various states of change. For instance, the TOP standards have been significantly modified and are nearing the ballot phase. Coordination needs to occur before these changes are balloted.
Midwest ISO Standards Collaborators	These SAR and associated draft standards changes go beyond what is needed to resolve the GO/TO GOP/TOP registration issue. The only real changes that are needed are to include adding GO and GOP applicability in the FAC-003 standard so that vegetation management can be enforced for lines built to interconnect generators without registering the GO/GOP as a TO/TOP. All additional changes just add confusion and cause significant coordination issues with other draft standard changes.This proposed SAR and associated standards’ modifications does not appear to have been coordinated with any other drafting team. There are many standards and requirements that are in various states of change. For instance, the TOP standards have been significantly modified and are nearing the ballot phase. Coordination needs to occur before these changes are balloted.
<b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT. The purpose of this SAR was to seek stakeholder views on the scope of requirements that may need modification, and most stakeholders who participated in this comment period support modifications that go beyond modifying only the Transmission Vegetation Management standard.	

Organization	Question 8 Comment
E.ON U.S.	<p>This SAR should only apply to those separate entity GOPs that already adhere to an OATT. Those GOPs should be required to register additionally as a TO/TOP. This should not apply to a GOP within a Corporation that includes TO/TOP that adhere to an OATT, and have already defined an internal division of responsibilities for the Transmission Interface between the GOP and TOP.</p>
<p><b>Response:</b> Based on a review of the full body of industry comments, we believe that there is a reliability need for this SAR. Further, registration issues are outside the scope of the SAR DT.</p>	
Energy Standards Working Group	<p>We commend the work of the team that produced the report and this SAR and suggest that the Standard Drafting Team give due deference to the report with the modifications that we have suggested in questions 4 and 5 above. In addition, EPSC would highlight the following conclusions that follow from the report:</p> <ul style="list-style-type: none"> <li>o The Generator Owner or Generator Operator that owns and/or operates a Generator Interconnection Facility, that is, a sole-use facility that interconnects the generator to the grid, should not be registered as a Transmission Owner or Transmission Operator by virtue of owning or operating its Generator Interconnection Facility</li> <li>o A Generator Interconnection Facility is considered as though part of the generating facility specifically for purposes of applying Reliability Standards to a Generator Owner or Generator Operator</li> <li>o After review of the existing Transmission Operator requirements that are not currently applicable to Generator Operators, no existing Transmission Operator requirements should apply to Generator Operators as a result of the Generator Interconnection Facility</li> </ul>
<p><b>Response:</b> The SAR DT thanks you for your comment. The SAR DT agrees with your conclusions.</p>	
Tenaska, Inc.	<p>We commend the work of the team that produced the report and this SAR and suggest that the Standard Drafting Team give due deference to the report with the modifications that we have suggested in questions 4 and 5 above. In addition, we would highlight the following conclusions that follow from the report:</p> <ul style="list-style-type: none"> <li>o The Generator Owner or Generator Operator that owns and/or operates a Generator Interconnection Facility, that is, a sole-use facility that interconnects the generator to the grid, should not be registered as a Transmission Owner or Transmission Operator by virtue of owning or operating its Generator Interconnection Facility</li> <li>o A Generator Interconnection Facility is considered as though part of the generating facility specifically for purposes of applying Reliability Standards to a Generator Owner or Generator Operator</li> <li>o After review of the existing Transmission Operator requirements that are not currently applicable to Generator Operators, no existing Transmission Operator requirements should apply to Generator Operators as a result of the Generator Interconnection Facility</li> </ul>

Organization	Question 8 Comment
	<b>Response:</b> The SAR DT thanks you for your comment. The SAR DT agrees with your conclusions.

## **Informal Comments on White Paper for Project 2010-07—Generator Requirements at the Transmission Interface**

The Project 2010-07—Generator Requirements at the Transmission Interface standard drafting team (drafting team) thanks all who provided comments during this stage of development. The [White Paper Proposal for Informal Comment](#) was posted for a 30-day informal public comment period from March 4, 2011 through April 4, 2011. The stakeholders were asked to provide feedback via email to the NERC Project Coordinator. 51 sets of comments were submitted.

[http://www.nerc.com/filez/standards/Project2010-07\\_GOTO\\_Project.html](http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html)

The SDT has completed the review of the informal comments from industry for Project 2010-07—Generator Requirements at the Transmission Interface. Each comment was reviewed and considered by the drafting team as it proposed modifications to FAC-001 and FAC-003 and developed the project’s background document, and it will continue to consider this stakeholder feedback as the project progresses. If a comment is not specifically addressed, it is likely because the drafting team has addressed it elsewhere or the comment did not add clarity or otherwise improve the quality of the proposed standards.

A majority of commenters supported the concepts in the white paper, which represent a focused but comprehensive approach to including responsibility for generator interconnection Facilities in NERC’s Reliability Standards. Most commenters agreed that the approach of developing specific changes to a limited number of standards was preferable to developing new definitions or revising existing definitions.

The drafting team received many comments on the general direction of the project:

- **Some suggested that an interim solution be implemented until the modified standards are approved.** The drafting team is providing input to NERC compliance staff upon request as it works toward an interim solution.
- **Some said that Generator Owners and Generator Operators that are radial in nature should not have to comply with any additional standards.** In this phase of the project, the drafting team’s goal was to identify and modify standards necessary to eliminate any reliability gaps related to extended generation interconnection Facilities. Ultimately, this shall prevent the registration of Generator Owners and Generator Operators as Transmission Owners and Transmission Operators. After review of all of the standards, the drafting team believes that it is appropriate to apply FAC-001 and FAC-003 to Generator Owners (in certain cases). This was confirmed by stakeholder comments during the informal comment period.
- **Some were concerned with the drafting team’s use the term “transmission” to label generator interconnection Facilities.** Several commenters were concerned with the use of “transmission lines” as a label for generator interconnection Facilities. While such a label has been applied in other contexts by certain entities, the drafting team has avoided that labeling in its modifications to FAC-001 and FAC-003 and its background documents.

- **Some were concerned that the white paper did not acknowledge interface agreements.** The drafting team recognizes that interface/interconnection agreements usually have explicit language about coordination between Generator Owners and Operators and Transmission Owners and Operators, but unfortunately these agreements are not viewed by regulatory authorities as a tool that can be used for meeting reliability standards.
- **Some encouraged the SDT to revisit certain standards that already apply to Generator Owners and Generator Operators because some standards split requirements by applicable entity.** The drafting team has reviewed the standards that already include Generator Owners and Generator Operators and determined that no changes to specific requirements are necessary. The drafting team attempted to better explain its rationale in these cases in the latest version of the background document.
- **Several addressed commercial issues in their comments on the white paper.** Such comments are outside the scope of this drafting team (and NERC Reliability Standards in general) and thus have not been addressed here.
- **Some pointed out reference errors in the white paper.** The drafting team is grateful for these comments and has attempted to remedy all errors in the resource document that has evolved from the white paper.

The drafting team received no comments indicating that it should have included standards other than the two identified (FAC-001 and FAC-003), but several commenters suggested modifications to the proposed approaches to FAC-001 and FAC-003.

A number of comments stated that the “trigger” for the application of FAC-001 should not be the receipt of a request, but rather should be based upon “the intent or obligation” to interconnect a new Facility to an existing interconnecting Facility that is owned by a generator. Accordingly, the drafting team has proposed language to address this concern. The intent of this modified language is to start the compliance clock when the generator Facility owner executes an Agreement to perform the reliability assessment required in FAC-002. This step should occur whether the generator voluntarily agrees to the interconnection request or is compelled by a regulatory body to do so. In either case, we expect the Generator Owner and the requestor to execute some form of an Agreement. The drafting team intentionally excluded a specific reference to the kind of Agreement (such as a feasibility study) in deference to comments that we should avoid comingling of commercial and reliability aspects in reliability standards.

Similarly, a majority of comments supported FAC-003 applicability to the Generator Owner but suggested some exclusion for a “short length” Facility. Accordingly, we modified the language to apply only to a Facility that extends at least ½ mile beyond the fenced boundary(ies) of the switchyard, generating station, or generating substation.

In addition to the majority of comments addressing the line length issue, the drafting team received some minority comments on FAC-003:

- **Some indicated that Generator Owners should not be added to FAC-003 because they are never an IROL circuit.** FAC-003 addresses circuits other than those associated with an IROL.
- **Some stated that changing FAC-003 would do nothing to prevent adverse reliability impacts, because a radial line can't cascade.** The drafting team believes there is a reliability-related need to apply FAC-003 to GOs with extended interconnection Facilities.
- **One commenter suggested a better connection between FAC-003 and FAC-014, stating that there is nothing in either standard where the Planning Coordinator is informing the Transmission Owners and Generator Owners of the applicability of their Facilities as outlined in the Facilities section 4.2.2 of FAC-003.** FAC-014-2 R5 addresses this issue.
- **One commenter suggested that the requirement simply be that the Generator Owner coordinates with the Transmission Owner to ensure that the generator interconnection Facilities are included.** The drafting team believes there is a reliability-related need to apply FAC-003 to Generator Owners with extended interconnection Facilities. An entity always has the opportunity to enter into a JRO where appropriate.

A majority of commenters also supported the drafting team's proposal to not adopt new defined terms. But many commenters said that if the new terms were not adopted, the drafting team needed to work to address registration issues related to Generator Owners and Generator Operators, especially those with ownership/operational responsibility for the Facility that interconnects the generator(s) to the Transmission Owner's Facility. A few stated that there needed to be a clearer delineation of responsibilities between the Generator Owner and Transmission Owner and the Generator Operator and Transmission Operator where ownership and operational responsibility of an interconnection Facility wasn't clearly understood. While the drafting team agrees with some of the comments, it is not empowered to make all changes which may be necessary to alleviate the concerns expressed in the comments.

However, during this process, the drafting team has been meeting with NERC and FERC staffs, regional compliance managers, and industry organizations to discuss possible solutions to the issue of concern to most Generator Owner/Generator Operators (e.g., registration as a Transmission Owner/Transmission Operator). The drafting team believes this issue, and the related concerns, have the attention of appropriate NERC and regional staffs and has volunteered to provide assistance in their efforts to address them.

The goal of the Project 2010-07 drafting team is to work with NERC and regional compliance enforcement and compliance registration staffs to develop a comprehensive package that will address all reliability gaps, whether real or perceived, so that entities are appropriately registered and the appropriate reliability standards are applied to those entities.

**\*\*Note about comments from February and March 2010 SAR Posting\*\***

During its review of these comments, the drafting team also returned to comments from its SAR posting in February and March of 2010, as many of the comments on the SAR posting dealt with the proposals in the original Ad Hoc Group for Generator Requirements at the Transmission Interface's Final Report. In



returning to these comments, the drafting team confirmed that it had addressed all relevant comments. Because of the narrower focus of the current Project 2010-07, many comments (such as those on the Ad Hoc Group's proposed definitions) were no longer relevant, but all others have been addressed:

- **Need to align project with compliance responsibility:** The drafting team is working with NERC and regional compliance staffs on exactly this.
- **The scope of the project is too broad:** The scope has been narrowed.
- **The project needs further clarification:** The original white paper posted for informal comment was developed to provide further clarification on the project. That white paper has been modified to be used as a background resource document.
- **The standards changes should be implemented all at once:** With only two standard changes being implemented and an interim solution being developed by NERC's compliance staff (in coordination with Regional compliance staff), the drafting team is not as concerned with implementing the changes simultaneously. If, for instance, FAC-001 changes are implemented before FAC-003 changes, the interim compliance solution will remain in effect until FAC-003 changes are also implemented to ensure that there are no gaps during the implementation periods.

The drafting team thanks all those who participated in the original SAR posting; the comments from that posting were invaluable during the transition from ad hoc group to standard drafting team.

# Consideration of Comments on Generator

## Requirements at the Transmission Interface – Project 2010-07

The Generator Requirements at the Transmission Interface Drafting Team thanks all commenters who submitted comments on the first formal posting for Project 2010-07—Generator Requirements at the Transmission Interface. These standards were posted for a 30-day public comment period from June 17, 2011 through July 17, 2011. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 43 sets of comments, including comments from approximately 143 different people from approximately 100 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

[http://www.nerc.com/filez/standards/Project2010-07\\_GOTO\\_Project.html](http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html)

The SDT thanks all stakeholders who provided comments. Your feedback helped the drafting team further modify its proposed standard changes, and the team believes that the changes are clearer and more technically sound because of it.

The SDT made a few substantive changes to both FAC-001 and both versions of FAC-003. With respect to FAC-001, many commenters suggested changes to both R2 and R3 to add clarity. The “activation” language in R2 now reads “...within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the Transmission System...” R3 has been modified so that it is clearer that only Generator Owners applicable in accordance with R2 are required to comply, and the word “protection” in R3.1.5 has been made lowercase. Per stakeholder comments, the SDT also removed the Generator Owner from R4, because they agree that that inclusion was redundant to language in R2. Because Generator Owners have been removed from the requirement (and thus the requirement is no longer within the SDT’s scope), the SDT reverted back to the original requirement language in the approved version of the standard.

Some commenters were still concerned with the 45 day “activation” point, and indicated that more time could be needed for compliance. The SDT reminded these commenters that the 45 day timeframe is 45 days from the time the entity has a study Agreement, not 45 days to execute the Agreement altogether. Any commenters who were concerned that their Facilities could never receive an interconnection request were reminded that if that’s the case, this standard would never apply to them. And those commenters who insisted that Generator Owners could never receive a request for interconnection were reminded that in the past (for instance, 134 FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities. Thus, the SDT thinks it is important to clarify the responsibilities related to such a request in NERC’s Reliability Standards.

With respect to FAC-003, many commenters focused on the half-mile qualifier in both versions of the standard. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: "...that extends greater than one mile beyond the fenced area of the generating station switchyard..." The SDT believes that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, the team maintains that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.

The majority of commenters did not suggest the addition of any standards or requirements to the team's scope of work, and a few commenters cautioned strongly against any additions. Some commenters suggested that the team consider including those standards and requirements listed in the June 2011 Cedar Creek and Milford FERC orders. The drafting team has considered the inclusion of the requirements listed in the Cedar Creek and Milford orders in the past, and we have been revisiting them throughout our process. We continue to conclude, with stakeholder support, that no additional substantive standard or requirement changes are necessary to achieve the goal of this project. With this posting, the drafting team has revisited those standards yet again and developed a comprehensive document and spreadsheet tracing our rationale (at every stage of the process) for not including additional standards or requirements. The team has elected to propose a slight clarifying change in PRC-004-2, but no changes to the applicability of that or any other standard.

While the drafting team will not be adding standards at this time because they do not believe such additions are technically justified or justified by stakeholder comments, the SDT will be seeking some additional informal feedback from industry groups to ensure that their technical justifications are sound and supported by others outside of the drafting team. The current draft documents showing the team's rationale and technical justification for including/excluding standards for revision under this project have been posted for information on the project page with this posting. If you have any specific feedback on these documents, you are welcome to email [mallory.huggins@nerc.net](mailto:mallory.huggins@nerc.net).

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 404-446-2560 or at [herb.schrayshuen@nerc.net](mailto:herb.schrayshuen@nerc.net). In addition, there is a NERC Reliability Standards Appeals Process.<sup>1</sup>

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<sup>1</sup> The appeals process is in the Standard Processes Manual:  
[http://www.nerc.com/docs/standards/sc/Standard\\_Processes\\_Manual\\_Approved\\_May\\_2010.pdf](http://www.nerc.com/docs/standards/sc/Standard_Processes_Manual_Approved_May_2010.pdf).

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1.	Mahmood Safi	Omaha Public Power Dist	MRO	1, 3, 5, 6										
2.	Chuck Lawrence	American Transmission Company	MRO	1										
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1.	John Sullivan	Ameren Services Co.	SERC	1									
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3.	Philip Kleckley	SC Electric & Gas Co.	SERC	1									
4.	Pat Huntley	SERC Reliability Corp.	SERC	10									
5.	Bob Jones	Southern Company Services	SERC	1									
6.	Group	Jesus Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X				
<b>Additional Member</b>		<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>									
1.	Tino Zaragoza	IID	WECC	1									
2.	Jesus Sammy Alcaraz	IID	WECC	3									
3.	Diana Torres	IID	WECC	4									
4.	Marcela Caballero	IID	WECC	5									
5.	Cathy Bretz	IID	WECC	6									
7.	Group	Brent Ingebrigtsen	LG&E and KU Energy	X		X		X	X				
No additional members listed.													
8.	Group	John Seelke	Public Service Enterprise Group	X		X		X	X				
<b>Additional Member</b>		<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>									
1.	Ken Brown	PSE&G	RFC	1, 3									
2.	Clint Bogan	PSEG Fossil	RFC	5									
3.	Peter Dolan	PSEG ER&T	RFC	6									
4.	Scott Slickers	PSEG Fossil	NPCC	5									
5.	Eric Schmidt	PSEG ER&T	NPCC	6									
6.	Mikhail Falkovich	PSEG Fossil	ERCOT	5									
9.	Group	Jonathan Hayes	SPP Reliability Standards Development Team		X								
<b>Additional Member</b>		<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>									
1.	Valerie Pinamonti	AEP	SPP	1, 3, 5									
2.	Newton Alan Ward	AEP	SPP	1, 3, 5									



Group/Individual	Commenter	Organization	Registered Ballot Body Segment											
			1	2	3	4	5	6	7	8	9	10		
3. Mahmood Safi	OPPD	SPP	1, 3, 5											
4. John Allen	SPRM	SPP	1, 4											
5. Mitch Williams	Western Farmers	SPP	1, 3, 5											
6. Robert Cox	Lee County Electric		NA											
7. Don Reinert	Westar	SPP	1, 3, 5, 6											
8. Robert Rhodes	SPP	SPP	2											
10. Group	Annette Bannon	PPL Supply Group						X	X					
<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>											
1. Leland McMillan	PPL Montana, LLC	WECC	5											
2. Don Lock	Lower Mount Bethel Energy, LLC	RFC	5											
3.	PPL Brunner Island, LLC	RFC	5											
4.	PPL Holtwood, LLC	RFC	5											
5.	PPL Martins Creek, LLC	RFC	5											
6.	PPL Montour, LLC	RFC	5											
7. Mark Heimbach	PPL EnergyPlus, LLC	MRO	6											
8.	PPL EnergyPlus, LLC	NPCC	6											
9.	PPL EnergyPlus, LLC	RFC	6											
10.	PPL EnergyPlus, LLC	SERC	6											
11.	PPL EnergyPlus, LLC	SPP	6											
12. John Cummings	PPL EnergyPlus, LLC	WECC	6											
11. Group	Jason Marshall	ACES Power Members							X					
<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>											
1. Darin Adams	East Kentucky Power Cooperative	SERC	1, 3, 5											
2. Susan Sosbe	Wabash Valley Power Association	RFC	3											
3. Mohan Sachdeva	Buckeye Power	RFC	3, 5											
12. Individual	Chris Higgins	Bonneville Power Administration		X		X		X	X					
13. Individual	Jack Cashin	EPSA						X	X					
14. Individual	Sandra Shaffer	PacifiCorp		X		X		X	X					
15. Individual	Janet Smith, Regulatory	Arizona Public Service Company		X		X		X	X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
		Affairs Supervisor											
16.	Individual	Bo Jones	Westar Energy	X		X		X	X				
17.	Individual	Antonio Grayson	Southern Company					X					
18.	Individual	Mike Laney	Luminant Power					X					
19.	Individual	Thad Ness	American Electric Power	X		X		X	X				
20.	Individual	Edward Cambridge	APS	X		X		X					
21.	Individual	Gretchen Schott	BP Wind Energy North America Inc.										
22.	Individual	Katy Mirr	Sempra Generation					X					
23.	Individual	Brian Evans-Mongeon	Utility Services, Inc.								X		
24.	Individual	Samuel Reed	Tri-State Generation and Transmission, Inc.	X				X					
25.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
26.	Individual	Jody Nelson	Georgia Transmission Corporation	X									
27.	Individual	Bill Rees	BGE	X									
28.	Individual	John Bee	Exelom	X		X		X					
29.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP					X					
30.	Individual	Dale Fredrickson	Wisconsin Electric			X	X	X					
31.	Individual	Keith Morissette	Tacoma Power	X		X	X	X	X				
32.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
33.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
34.	Individual	Amir Hammad	Constellation Power Generation					X					
35.	Individual	Kirit Shah	Ameren	X		X		X	X				
36.	Individual	Rex Roehl	Indeck Energy Services					X					
37.	Individual	Chad Bowman	CHPD	X		X		X					
38.	Individual	Andrew Z Pusztai	American Transmission Company	X									
39.	Individual	Michael Falvo	Independent Electricity System Operator		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
40.	Individual	Doug Hohlbaugh	FirstEnergy Corp	X		X	X	X	X				
41.	Individual	Sandy O'Connor	TransAlta Centralia Generation LLC	X				X					
42.	Individual	Natalie McIntire	American Wind Energy Association										
43.	Individual	Donald Brookhyser	Cogeneration Association of California										

## 1. Do you support the proposed redline changes to FAC-001-1?

**Summary Consideration:** The SDT thanks all individuals and groups who provided feedback. The majority of comments indicated support for the SDT's changes to FAC-001, and the team has made additional changes, based on commenter feedback, where they believe those changes add clarity.

Commenters suggested changes to both R2 and R3 to add clarity. The "activation" language in R2 now reads "...within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System..." R3 has been modified so that it is clearer that only Generator Owners applicable in accordance with R2 are required to comply, and the word "protection" in R3.1.5 has been made lowercase. Per stakeholder comments, the SDT also removed the maintenance requirements for the Generator Owner from R2, and the Generator Owner from R4 altogether. Because Generator Owners have been removed from the requirement (and thus the requirement is no longer within the SDT's scope), the SDT reverted back to the original requirement language in the approved version of the standard.

Some commenters were still concerned with the 45 day "activation" point, and indicated that more time could be needed for compliance. The SDT reminded these commenters that the 45 day timeframe is 45 days from the time the entity has a study Agreement, not 45 days to execute the Agreement altogether. Any commenters who were concerned that their Facilities could never receive an interconnection request were reminded that if they are correct, this standard would not apply to them. Those commenters who insisted that Generator Owners could never receive a request for interconnection were reminded that in the past (for instance, 134 FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities. Thus, the SDT believes it is important to clarify the responsibilities related to such a request in NERC's Reliability Standards.

Some commenters brought up tariff-related issues. While the SDT has made changes attempting to clarify what was perceived by some commenters to be ambiguous qualifying language in R2, and while the commenters are correct that a valid interconnection would likely need to go through the generator interconnection process under its applicable tariff, it would be inappropriate for any market- or tariff-related language to be included in a NERC Reliability Standard. The goal of the drafting team was simply to clarify a Generator Owner's obligations, under NERC's Reliability Standards, for handling an interconnection request and the related interconnection requirements.

Several commenters also suggested changes to VRFs and VSLs. Because the SDT did not make any substantive changes to R1 or R4, the team only made changes to the VSLs or VRFs if we were correcting a typo; anything substantive would be outside the scope of this SDT. In the case of R2 and R3, changes were made per commenter suggestions.

Finally, the formatting error in the Applicability section has been corrected.

For a more detailed explanation of the team’s rationale, please see the accompanying FAC-001-1 technical justification.

Organization	Yes or No	Question 1 Comment
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	No	<p>In general, the NSRF supports the changes to FAC-001-1. However the 45 days to execute an agreement would be a significant burden on a Generator Operator that does not have an existing process in place. The NSRF believes an aggressive but realistic time frame is 120 days. This would allow sufficient time to develop the procedure and obtain the necessary technical and legal reviews.</p> <p>Please clarify why "Protection" is capitalized in section 3.1.5. "Protection System" is defined by NERC but "System Protection" is not.</p> <p>Recommend the "half mile" statement be included within the Applicability section of this Standard as it stated in FAC-003-X.</p>
<p><b>Response:</b> Thank you for your comment. The team proposed 45 days from the time the entity has a study Agreement, not 45 days to execute the Agreement altogether. Please see the SDT’s accompanying FAC-001-1 technical justification for a more detailed explanation of the team’s rationale for using that time frame. No change made.</p> <p>“Protection” in 3.1.5 has been made lowercase.</p> <p>With respect to the “half mile” comment, an entity could receive an interconnection request for its interconnection Facility at any point along that Facility. An exemption or exclusion based on the length of the Facility is not justified because doing so would create a reliability gap. No change made.</p>		
Public Service Enterprise Group	No	<p>The language in R2 needs to be clarified with regards to the term “its existing generation Facility.” The interconnection leads are considered part of the “existing generation Facility,” but so are the generator, generator step-up transformer and other equipment associated with the generator. The project Background Resource Document (p.2) makes it clear that the interconnection to an existing generator facility is contemplated to be to the “existing interconnecting Facility that is owned by a generator” - i.e., the generator’s interconnection leads. We propose that the term “its existing generation Facility” be replaced with “the Generator Owner’s existing interconnecting transmission Facility.”</p>
<p><b>Response:</b> Thank you for your comment. We agree that some additional specification could be useful, and we have used the suggested</p>		

Organization	Yes or No	Question 1 Comment
clarifying language.		
SPP Reliability Standards Development Team	No	<p>We are concerned that some of the language is ambiguous. We would like to be clear that placing new requirements on Generator Owners that are already in place and have been in place under FERC policy is inaccurate. We want to make sure that regardless of what the generator tie line is classified as, that a valid interconnection would go through the Generator Interconnection process under its applicable tariff.</p> <p>Format error in 2.4.1 should read 4.2.1 in applicability.</p> <p>We would like to see more definition in applicability section 4.2. How does the Generator Owner get involved in this process?</p> <p>The VRF for R4 is listed as a medium and appears to us as an administrative requirement. We would recommend that the VRF be changed to low.</p> <p>The moderate and high VSL for R1 seems to be duplicative. We would recommend taking a second look and would recommend that the high should be that “if you failed to do two of the following”.</p> <p>We would recommend that the VSL on R4 read: “The responsible entity failed to make the requirements available within 30 business days after a request.”</p>
<p><b>Response:</b> Thank you for your comment. We have attempted to clarify what was perceived by some commenters to be ambiguous qualifying language. You are correct that a valid interconnection would likely need to go through the generator interconnection process under its applicable tariff, but it would be inappropriate for any market- or tariff-related language to be included in a NERC Reliability Standard. The goal of the drafting team was simply to clarify a Generator Owner’s obligations, under NERC’s Reliability Standards, for handling an interconnection request and the related interconnection requirements.</p> <p>The format error in the applicability section has been corrected.</p> <p>A Generator Owner can get involved in the process by receiving a request for interconnection on their Facility and executing an Agreement to evaluate the reliability impact of that request. The team has attempted to clarify to qualifying language in the applicability section with its latest proposed changes. Please see the SDT’s accompanying FAC-001-1 technical justification for a more detailed explanation of the team’s rationale.</p> <p>With respect to the VRF for R4, we agree that “low” might be more appropriate, but that change is outside the scope of this drafting team. Your suggestion will be submitted in a Suggestion Form and added to NERC’s Issues Database to be addressed in a future project.</p>		

Organization	Yes or No	Question 1 Comment
<p>With respect to the moderate and high VSLs for R1, we agree that they are duplicative and believe this was a typo. Change made.</p> <p>With respect to the proposed language change in the VSL for R4, while we agree that the VSL should be written in the negative rather than the positive that change would be outside the scope of this drafting team. Your suggestion will be submitted in a Suggestion Form and added to NERC's Issues Database to be addressed in a future project.</p>		
PPL Supply Group	No	<p>A Generator Owner subject to the proposed standard (i.e., with an executed Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility) should only be responsible for evaluating the impact of such interconnection on its facilities. Generation Owners should have no responsibility for evaluating impacts on interconnected or adjacent Transmission Owner systems. GOs do not have staff trained or tools available to perform the studies necessary to evaluate reliability impacts of such interconnections on Transmission Owner systems which can extend geographically far beyond the POI. The SDT should clarify that Transmission Owners are solely responsible for evaluating and addressing any impacts on their systems.</p>
<p><b>Response:</b> Thank you for your comment. In the past (for instance, 134 FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities, and the drafting team thinks it is important to clarify the responsibilities related to such a request in NERC's Reliability Standards. The drafting team does not believe the standard as written requires the Generator Owner to be responsible for any interconnection Facility past the point of interconnection with the Transmission Owner's Facility. Please see the SDT's accompanying FAC-001-1 technical justification for a more detailed explanation of the team's rationale. No change made.</p>		
ACES Power Members	No	<p>We support the concept of modifying FAC-001-1 to include Generation Owners that own transmission lines that interconnect them to the BES for the purpose of eliminating the need to register Generation Owners as Transmission Owners. However, there are serious issues with the implementation of the FAC-001-1. The changes conflict with the tariff process of many established markets as well as the FERC pro forma tariff. Requests to interconnect are generally governed by tariffs. The request will be submitted to the transmission provider established by the tariff. The transmission provider will then perform the necessary studies such as system impact or feasibility studies to determine any necessary upgrades through its long-term planning function. After the completion of these studies or in parallel with them, the Transmission Owner (or Generation Owner that owns transmission) will perform the facility connection study. This may or may not require an additional contract as it may be governed completely under the tariff or may be covered under a blanket agreement in an organized</p>

Organization	Yes or No	Question 1 Comment
		<p>market. The language referring to the executed Agreement in the standard should be dropped as it is confusing and may not cover many situations. Rather, the standard should apply to the Generation Owner that owns Transmission and is not registered as Transmission Owner.</p> <p>R2 should be modified such as the Generation Owner that owns Transmission is required to create facility connection requirements upon request from the Planning Coordinator or Transmission Planner. While the NERC Functional Model is not clear on the function that performs the interconnection study, it likely will be either the Transmission Planner or the Planning Coordinator. Interconnection studies are typically long-term planning studies. Thus, it is the Transmission Planner or Planning Coordinator that will receive the interconnection request and determine on whose equipment will be impacted.</p> <p>R3 is problematic and contradicts the purpose of R2. R3 requires the Generation Owner that owns Transmission to have Facility connection requirements at all times. It appears the drafting team intended for R3 to simply define what must be included in the facility connection requirements. To do this, we suggest the drafting team remove the Generation Owner that owns Transmission from the requirement and copy the part 3.1 and its sub-parts to R2. The following language should be struck from R2: "to ensure compliance with NERC Reliability Standards and applicable Regional Entity, subregional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements". These requirements already exist elsewhere and inclusion here creates the potential for double jeopardy. R4 should be struck. There is no need for the Generator Owner that owns transmission to maintain its facility connection requirements. They should only be required to review and update them when they get a request. Tariff processes will already require them to make the facility connection requirements available to interconnection requesters.</p>
<p><b>Response:</b> Thank you for your comment. The drafting team believes that the execution of an Agreement to evaluate the reliability impact of interconnecting a third party Facility is the appropriate "activation" point for this standard for applicable Generator Owners. We have changed the language in the requirement to accommodate situations where it was not the Generator Owner itself that executed the Agreement. Please see the SDT's accompanying FAC-001-1 technical justification for a more detailed explanation of the team's rationale.</p> <p>R3 has been modified to more clearly apply only to Generator Owners in accordance with R2. Per your suggestion about maintenance, the drafting team has removed the maintenance obligation for Generator Owners. For more information on our rationale with respect to this, please see the accompanying FAC-001-1 technical justification document.</p>		
Westar Energy	No	We suggest the VRF for R4 be changed from medium to low, as it is administrative in nature. We recommend the high VSL for R1 read, "The Transmission Owner failed to do two of the



Organization	Yes or No	Question 1 Comment
		following.”
<p><b>Response:</b> Thank you for your comment. We agree that “low” might be more appropriate, but that change is outside the scope of this drafting team. Similarly, any change to the VSLs for R1 is outside the scope of this drafting team as that requirement does not include any reference to Generator Owners; we only made changes if the previous text appeared to have a typo. Your suggestions will be submitted in a Suggestion Form and added to NERC’s Issues Database to be addressed in a future project.</p>		
Southern Company	No	<p><b>A.</b> Southern does not think that the revision to FAC-001-1 is necessary. A Generator Owner (GO) cannot assess reliability impacts to the Bulk Electric System (BES) and determine acceptability without support and involvement of the applicable owner and operator of the Transmission System. A generator tie-line does not equate to a Transmission System. A GO must already adhere to a TO’s Facility connection requirements whether the GO wants to connect additional facilities or a third parties facilities to its own interconnection Facilities. Stated another way, the GO does not need Facility Connection requirements to govern how multiple units are tied to a collector bus so why are they needed for a third party to connect to an existing tie-line? In either case it is the interconnected TO that has connection requirements that must be fulfilled. The GO’s Interconnection Agreement would prohibit it from connecting additional facilities without a new application for Interconnection Service with its interconnected Transmission Provider. A GO should not need to develop “connection requirements” unless it is in the business of owning and operating facilities independently of its interconnected Transmission Provider.</p> <p>We do not believe a reliability gap exists in FAC-001-1 because the requestor for interconnecting another Facility to an existing generation Facility must coordinate with the applicable TO, TP, and PA in accordance with FAC-002-0 to ensure they meet all applicable facility connection and performance requirements. If and when there is an agreement in place for a third party to connect to a generator tie-line then the tie-line would become part of the integrated system and its purpose and the owner’s function would likely warrant registration as a TO/TOP and FAC-001 would then apply. The following excerpt from the 2010-07 Background Resource Document acknowledges that this may be necessary: “The drafting team also acknowledges that, if another party interconnects to a Facility owned by a Generator Owner, there may be the need to address MOD or TPL standards. However, the drafting team believes that this, too, is best handled through specific evaluation, perhaps accompanied by changes to the compliance registry. Entities that face this kind of scenario may also meet criteria applicable to other registrations such as Transmission Service Provider or Transmission Planner.”</p>

Organization	Yes or No	Question 1 Comment
		<p><b>B.</b> If the Project 2010-07 Drafting Team decides to continue revising FAC-001-1, there are jurisdictional, interconnection policy and open access transmission tariff issues that will need to be considered.</p> <p><b>(1)</b> Because of (a) jurisdiction under Section 215, (b) FERC’s interconnection policy, and (c) the requirements of the pro forma open access transmission tariff (OATT), a GO should not be required to comply with FAC-001-1 until that GO’s generating Facility reaches commercial operation.</p> <p><b>(a)</b> Jurisdiction under FPA Section 215. First, it is not clear that NERC or FERC has jurisdiction under FPA Section 215 to require generation facilities that have not actually reached commercial operation to be subject to reliability standards. Section 215(a)(2) of the FPA defines the “Electric Reliability Organization” as “the organization certified by the Commission ... the purpose of which is to establish and enforce reliability standards for the bulk-power system, subject to Commission review.” Further, (a)(3) provides that “The term ‘reliability standard’ means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system. The term includes requirements for the operation of existing bulk-power system facilities ... the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system ....” Thus, under Section 215 NERC can develop reliability standards that address requirements for existing bulk-power system facilities (i.e., facilities that have reached “commercial operation”) and for the design of planned additions or modifications. It is logical to interpret the phrase “design of new facilities” as meaning that new facilities must be designed to comply with existing reliability standards. However, it is not clear that this provision should be interpreted as requiring that a generating facility that has not yet reached commercial operation should be subject to reliability standards (including audit and penalties). Therefore, the GO with the existing generation facilities should not be required to incorporate the proposed generation facility into its Facility connection requirements before the proposed generation facility is subject to NERC or FERC jurisdiction.</p> <p><b>(b)</b> FERC’s interconnection policy. In addition, the revised FAC-001 would appear to place restrictions on interconnection customers in contravention of Order Nos. 2003 and 2006 (Standard Large and Small Interconnection Procedures and Agreements). FERC was very concerned about the ability of interconnection customers to interconnect their generating facilities and gave them a fair amount of flexibility. However, this revised</p>

Organization	Yes or No	Question 1 Comment
		<p>FAC-001 would appear to restrict some of this flexibility.</p> <p><b>(i)</b> Order No. 2003 gives the interconnection customer the ability to terminate a proposed interconnection on ninety days notice. Therefore, the interconnection customer is not required to build the facility. However, this revised FAC-001 appears to assume that the interconnection customer does not have this flexibility. What if the interconnection customer (the GO building a new generator on its site or the third party building a new generation facility) decides to terminate the Large Generator Interconnection Agreement (LGIA) or not proceed with the generation facility? In such event, the GO may be required to revert to its previous Facility connection requirements in order to accommodate the original configuration.</p> <p><b>(ii)</b> The LGIA permits modifications to the proposed interconnection. How would this affect the Facility connection requirements? How long would the GO have to revise its Facility connection requirements? In the event that there is a single modification, or perhaps multiple modifications, how does the GO stay in compliance with this standard?</p> <p><b>(iii)</b> FAC-001-1, R4 provides that each GO with Facility connection requirements and each TO shall maintain Facility connection requirements and make documentation of these requirements available to users of the Transmission System upon request. However, Large Generator Interconnection Procedures (LGIP), Section 3.4 requires the posting of certain interconnection information but the identity of the interconnection customer is not to be disclosed (unless it is an Affiliate). Requirement R4 would appear to potentially require disclosure of information and (more importantly) of the interconnection customer's identity in contravention of the requirements in Order No. 2003 and the LGIP.</p> <p><b>(c)</b> OATT requirements. The definition of "applicable Generator Owner" (Section 4.2.1) and Requirement R2 provide that the GO will have an executed Agreement to evaluate the impact of interconnecting a new facility to the GO's existing generation facility. This statement is ambiguous. This statement could be understood to mean that the GO of the existing generation Facility will enter into an Agreement with the GO proposing to interconnect and the existing GO will evaluate the impact of the proposed interconnection. However, requests to interconnect new generation are processed under an OATT. In that case, it would be the Transmission Provider (not the existing GO) that would evaluate the impact of interconnecting the new facility. Thus, the language in FAC-001-1 would need</p>

Organization	Yes or No	Question 1 Comment
		<p>to be revised to clarify that the owner of the new facility will need to interconnect under the OATT of an appropriate Transmission Provider (i.e., the Transmission Provider to which the existing GO is interconnected, not with the existing GO). Therefore, the owner of the new facility will most likely be the entity with the executed Agreement (with the Transmission Provider). Another consideration is that the existing GO could be developing a merchant transmission line. In that case, the existing GO would need to evaluate whether it needs have its own OATT and OASIS. In that case, the new generator owner would be interconnecting to the existing GO. However, the existing GO's line would not be a generator tie-line. This issue is not clear from the draft standard.</p> <p><b>(2)</b> The following are suggested changes to FAC-001-1.</p> <p><b>(a)</b> We recommend the Purpose statement be revised to state, "To avoid adverse impacts on BES reliability..."</p> <p><b>(b)</b> The numbering for "Applicable Generator Owner" should be 4.2.1 instead of 2.4.1.</p> <p><b>(c)</b> It is not clear who may request to interconnect to the Generator Owners' facility. The Background Resource document states that "[b]ecause Generator Owners may be requested to allow interconnection to their Facilities" - this would imply that a third party may request interconnection to the Generator Owner's Facilities. However, draft FAC-001-1 discusses "interconnecting another Facility to its existing generation Facility." This issue needs to be clarified. Is it simply when a Generator Owner proposes to add a new facility to its existing facility or does it also include a third party request to interconnect to the Generator Owner facilities?</p> <p><b>(d)</b> R4 should be revised to delete the requirement to maintain the Facility connection requirements because this is redundant to language in R1 (and R2, which we believe is not needed). In addition, R4 should be revised to state, "...on requests within five (5) business days" since the time requirement is essential for measurement of non-compliance as indicated by the VSLs.</p> <p><b>(e)</b> The Severe VSL for R3 should be revised to delete the second portion which states, "The responsible entity does not have Facility connection requirements." This non-compliance would be covered by the first portion of the two-part OR requirement (...four or more...). It is also covered by the Severe VSL of R1.</p> <p><b>(3)</b> Effect of the proposed revisions to FAC-001-1 on FAC-002-1.</p>

Organization	Yes or No	Question 1 Comment
		<p><b>(a)</b> As drafted, there are scenarios under which a new GO may attempt to interconnect to an existing GO even though, as explained above, the interconnection should actually be done to the appropriate Transmission Provider. If the appropriate Transmission Provider is not included in the evaluation of the interconnection various types of harm may occur. In such event, the TPs and PAs should be indemnified from any liability with respect to performance of the evaluations required by FAC-002.</p> <p><b>(b)</b> FAC-001 and FAC-002 should be revised to be clear that the existing GO and any new GOs must coordinate any interconnection with the appropriate Transmission Provider, TP and PA.</p>
<p><b>Response:</b> Thank you for your comment. The drafting team has considered the jurisdictional, interconnection policy and open access transmission issues that you raise. But in the past (for instance, 134 FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities, and the drafting team thinks it is important to clarify the responsibilities related to such a request in NERC’s Reliability Standards. You are correct that a jurisdictional, interconnection policy, and open access transmission tariff issues maybe have an impact, but it would be inappropriate for any market- or tariff-related language to be included in a NERC Reliability Standard. The goal of the drafting team was simply to clarify a Generator Owner’s obligations, under NERC’s Reliability Standards, for handling an interconnection request and the related interconnection requirements. Please see the SDT’s accompanying FAC-001-1 technical justification for a more detailed explanation of the team’s rationale.</p> <p>With respect to your suggested changes in section 2:</p> <ol style="list-style-type: none"> <li>Any change to the purpose statement would be outside the scope of this team. Please submit a <a href="#">Suggestion Form</a> to NERC if you continue to feel that this change is necessary.</li> <li>That formatting change has been made.</li> <li>The drafting team has worked to clarify who may request to interconnect to the Generator Owner’s Facility.</li> <li>The maintenance requirements in R2 and R4 are no longer applicable to Generator Owners. For more information on our rationale on this issue, please see the accompanying FAC-001-1 technical justification document.</li> <li>The drafting team agrees that the second portion of the Severe VSL for R3 is redundant. While other changes to VSLs and VRFs have been outside the scope of the team, because the SDT has made changes to R3, we feel comfortable making this change.</li> </ol> <p>For a more detailed justification of our changes to FAC-001 with respect to your comments in the third section, please see the FAC-001 justification document that is posted with these standard changes.</p>		
American Electric Power	No	There are substantial reliability issues, as well as additional regulatory, tariff, coordination, and generator and interconnection facility issues, which need to be dealt with before AEP could agree to such requirements. It is not clear that a generator can receive a request for

Organization	Yes or No	Question 1 Comment
		interconnection. We recommend adding qualifier text which states the standard only applies *if* an entity plans to allow such a requested interconnection. This would allow an entity to document that they do not plan to allow such interconnections.
<p><b>Response:</b> Thank you for your comment. In the past (for instance, 134 FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities, and the drafting team thinks it is important to clarify the responsibilities related to such a request in NERC’s Reliability Standards. No change made.</p>		
APS	No	Do not agree with adding GO to FAC-001-1
<p><b>Response:</b> Thank you for your comment. The vast majority of stakeholder commenters and the drafting team continue to support the addition of the Generator Owner to the applicability of FAC-001-1. No change made.</p>		
Exelon	No	Exelon does not agree that this standard should be broadly applied to a GO. GOs who do not own a switchyard and whose point of interconnection is a disconnect switch associated with the generator leads prior to the switchyard should be excluded from this standard. If a group of GOs share a generator tie line, then the associated Interconnect Agreement that each of the GO has with the applicable TO and/or TOP should address how these shared connections will effect the system. GOs may not have the resources or expertise to conduct the required interconnect studies to meet this standard
<p><b>Response:</b> Thank you for your comment. The standard does not automatically apply to all Generator Owners; rather, it applies only to those Generator Owners with an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the Transmission System. The drafting team believes that it has built the appropriate amount of time into the standard to allow an applicable Generator Owner to evaluate the impact of an Interconnect Agreement and obtain or contract for the necessary resources and expertise. Please see the SDT’s accompanying FAC-001-1 technical justification for a more detailed explanation of the team’s rationale. No change made.</p>		
Manitoba Hydro	No	The Applicable Entities now include a Generator Owner that meets the following condition: ‘Generator Owner with an executed Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility.’ A Generator Owner should not have such power. In many instances Generator Owners do not have the models or expertise to perform interconnection studies to determine if there is an impact on the Transmission Network. All interconnection requests should be implemented by the Transmission Owner (TO) regardless if the interconnection point is within a Generation Owner

Organization	Yes or No	Question 1 Comment
		<p>facility or End-User facility. The TO is in the best position to set unbiased connection requirements to ensure the reliability of the BES is maintained. If a mechanism is created to allow interconnection to a BES line owned by Generator Owner, then it is essential for this Generator Owner providing this interconnection service to be a TO to ensure all reliability standards, including the protection standards, are met so the reliability of the BES is maintained. The drafting team should demonstrate where this situation is occurring. If the redline changes are implemented, could Generator Owner #1 permit Generator Owner #2 to interconnect one of their generators within Generator Owner #1's Facility? Would Generator Owner #2 then need to have an executed Agreement to permit further generator interconnection? From a Transmission Owner viewpoint, it is tough enough to coordinate generator connection queues among adjacent TOs. Having to coordinate with Generator Owners as well would greatly increase the complexity of coordination.</p>
<p><b>Response:</b> Thank you for your comment. In the past (for instance, 134 FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities, and the drafting team thinks it is important to clarify the responsibilities related to such a request in NERC's Reliability Standards. No change made.</p>		
American Transmission Company	No	<p>R1 wording in this draft only requires having published Facility connection requirements, but speaks nothing of specific required content of this published document. (R1) VSLs specifically reference R1. If VSLs continue to include assessment of how many R3 (R2 in present standard) requirements are met, a TO potentially has a redundant obligation under two separate requirements. R1 and R3 do not read in a manner consistent with (R1) VSLs. Since R2 only applies to Generator Owners, the (R2) VSL should use "Generator Owner" in place of "responsible entity."</p>
<p><b>Response:</b> Thank you for your comment. The drafting team has removed the second portion of the Severe VSL for R3 to eliminate potential redundancy with the VSLs for R1 and R2. The VSL for R2 now refers to "Generator Owner" rather than "responsible entity."</p>		
Xcel Energy	Yes	<p>We believe it would be helpful to put explanatory wording in that if an entity is already registered as a Transmission Owner and Generator Owner, the Generator Owner portion of that entity would not have to have a separate set of interconnection requirements.</p>
<p><b>Response:</b> Thank you for your comment. The Facility in question in the standard would either be owned by the Generator Owner or the Transmission Owner. The owner must meet the requirement. The SDT does not determine how an entity complies, though we could expect that if an entity is already an Transmission Owner, it could easily simply apply its already existing set of interconnection requirements to any</p>		



Organization	Yes or No	Question 1 Comment
new Facilities that are applicable under this standard.		
Ingleside Cogeneration LP	Yes	However, there may need to be a variance for ERCOT because the Power Generating Companies in ERCOT are not allowed to own transmission assets.
<p><b>Response:</b> Thank you for your comment. If companies in ERCOT are not allowed to own transmission assets, the drafting team assumes that they would also never be in a position to have an Agreement to execute the reliability impact of an interconnection request. No change made.</p>		
Georgia Transmission Corporation	Yes	We commend the drafting team for their efforts to address gaps in Facility Connection Requirements. We believe that the requirements under R3 should be limited to Generator owned equipment to avoid duplication of efforts. A Generator Owner receiving an interconnection request is required to submit an interconnection request to the Transmission Owner which in turn would study the impact of such a request on the Transmission System. Therefore there is no gap as far as the Integrated Transmission System that the third party is interconnecting to through the Generator Owner. However, Generator Owners are responsible for verifying that their equipment is capable of accommodating the interconnection request.
<p><b>Response:</b> Thank you for your comment. The SDT does not believe that R3 is duplicative; there is no reason to assume that the Transmission Owner or the applicable Generator Owner would be addressing anything but the equipment that it owns. No change made.</p>		
BGE	Yes	This change closes the gap in areas not already covered under FAC-003-1 in a continuous improvement effort to ensure vegetation-related transmission reliability for applicable lines.
<p><b>Response:</b> Thank you for your comment.</p>		
FirstEnergy Corp	Yes	FirstEnergy (FE) appreciates the drafting team's careful consideration of the comments made by FE during the most recent informal comment period. The changes made to FAC-001 alleviate FE's prior concern related to a Generator Owner needing to maintain and publish a Facility Connection requirements document regarding facilities which are not yet subject to Open Access provisions. FE supports the team's changes to FAC-001-1 and the concept that a connection requirement document would be required upon the initial or 1st time a Generator Owner executes an Agreement to perform the reliability assessment required in FAC-002-1.
<p><b>Response:</b> Thank you for your comment.</p>		



Organization	Yes or No	Question 1 Comment
Sempra Generation	Yes	Sempra Generation supports the proposal for the compliance obligations under R2 associated with an interconnection request not to be triggered until an interconnection study agreement has been executed.
<b>Response:</b> Thank you for your comment.		
Arizona Public Service Company	Yes	These comments supersede the previous comments submitted by Arizona Public Service Company on July 7, 2011.
<b>Response:</b> Thank you for your comment.		
SERC OC Standards Review Group	Yes	Consider a better definition of what constitutes an “applicable” generator owner or point to the document that explains the definition.
<b>Response:</b> Thank you for your comment. The drafting team attempted to clarify the description of an “applicable” Generator Owner in the latest standards changes.		
Imperial Irrigation District (IID)	Yes	
PacifiCorp	Yes	
Ameren	Yes	
Luminant Power	Yes	
Constellation Power Generation	Yes	
SERC Planning Standards Subcommittee	Yes	
Duke Energy	Yes	

Organization	Yes or No	Question 1 Comment
Tri-State Generation and Transmission, Inc.	Yes	
Electric Market Policy	Yes	
Bonneville Power Administration	Yes	
Indeck Energy Services	Yes	
CHPD	Yes	
BP Wind Energy North America Inc.	Yes	
Independent Electricity System Operator	Yes	
Tacoma Power	Yes	
Northeast Power Coordinating Council	Yes	
TransAlta Centralia Generation LLC	Yes	
EPSA		<p>Background: The Electric Power Supply Association (EPSA) endorsed the initial recommendations of the Ad Hoc Group for Generator Requirements at the Transmission Interface, offered informal comments on the March 2011 White Paper Proposal for Project 2010-07 and now appreciates this opportunity to provide comments on the questions posted June 17, 2011. Since NERC's creation of the "GOTO Team" in February of 2009, EPSA has supported the efforts of Ad-Hoc Group and now the Project 2010-07 Standards Drafting Team (SDT). While EPSA members' compliance registration includes several functional entity types, the bulk of competitive suppliers' registrations are as Generator Owners (GOs) and Generator</p>

Organization	Yes or No	Question 1 Comment
		<p>Operators (GOPs).</p> <p>EPSA applauds the SDT’s decision to recommend the use the “intent of obligation” as the reason for application of FAC-001 rather than the receipt of request for interconnection and thereby supports the revisions to FAC-001-1. The proposed modification to FAC-001 (a new R2) would require a GO to develop “Facility connection requirements” within “45 days of executing an Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility...” The use of the agreement execution is a more reasonable triggering mechanism for FAC-001 application and compliance. The SDT’s recommendation intentionally excluded specific reference to the form of agreement to avoid commingling commercial and reliability aspects in reliability standards.</p> <p>However, the existing language may still may mix commercial and reliability issues. The accompanying project Background Resource Document (p.2) makes it clear that the interconnection to an existing generator facility is contemplated to be the “existing interconnecting Facility that is owned by a generator” - that is, the generator’s lead. The generator’s leads are considered part of the “existing generator Facility,” however, the generator, step-up transformer and other equipment that is within the generator switchyard can also be considered part of the Facility. FERC requires all transmission facilities to be available for “open access.” A generator lead would become open access if another customer interconnected to it. Therefore FAC-001-1 could be made clearer by modifying the language regarding the 45-day trigger as follows: within “45 days of executing an Agreement to evaluate the reliability impact of interconnecting another Facility to its the Generator Owner’s existing generation interconnecting transmission Facilities...” This modification would make it clear that the requirement does not apply to an entity that wants to, for example, connect a new generator within the fenced-in site of the existing generator, but instead only applies to request to interconnect to the generator lead.</p>
<p><b>Response:</b> Thank you for your comment. The drafting team has attempted to make this clarification regarding the “activation” of the applicability of this standard with respect to Generator Owners.</p>		
Utility Services, Inc.		
LG&E and KU Energy		

Organization	Yes or No	Question 1 Comment
Wisconsin Electric		

**2. Do you support the one year compliance timeframe for Generator Owners as proposed in the Implementation Plan for FAC-001-1?**

**Summary Consideration:** Most commenters supported the one year compliance timeframe for Generator Owners as proposed in the Implementation Plan for FAC-001-1. A few suggested a longer timeframe, but the drafting team believes it has built in the appropriate amount of time by giving a year in the implementation plan and then waiting to “activate” the standard until a Generator Owner has an executed Agreement to evaluate the reliability impact of the interconnection request.

Organization	Yes or No	Question 2 Comment
Manitoba Hydro	No	See question #1 comments. We do not support changing the applicability of FAC-001-1 to include Generator Owners ‘with an executed Agreement’ or Generator Owners that own BES transmission.
<b>Response:</b> Thank you for your comment. Please see our response to your Question 1 comments above.		
Ingleside Cogeneration LP	No	As drafted, the document still refers to generation interconnection lines as transmission lines in critical places. We understand that the SDT has taken significant steps to minimize this in both FAC-001 and FAC-003 and has had discussions with NERC about not registering GOs as TOs; however, this lack of distinction between high voltage generation interconnection lines and actual transmission lines still presents a difficult situation for Generations Owners and a source of contention with Reliability Entities. This could be resolved somewhat by using the non-defined term “generation interconnection lines” in place of “transmission lines” in, for example, section 4.3.1. Since the term “transmission line” is also undefined, this would seem to be a reasonable approach.
<b>Response:</b> Thank you for your comment. We have provided a disclaimer about the use of the term “transmission lines” in FAC-003, and have avoided use of the term elsewhere.		
APS	No	Leave the GO out of the standard.
<b>Response:</b> Thank you for your comment. In the past (for instance, 134 FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities, and the drafting		

Organization	Yes or No	Question 2 Comment
<p>team thinks it is important to clarify the responsibilities related to such a request in NERC's Reliability Standards by including applicable Generator Owners in FAC-001-1.</p>		
SERC OC Standards Review Group	No	We feel that an 18 month implementation plan would be more conducive for generators to meet these new requirements
<p><b>Response:</b> Thank you for your comment. The drafting team believes it has built in an adequate amount of time by giving a year in the implementation plan and then waiting to "activate" the standard until a Generator Owner has an executed Agreement to evaluate the reliability impact of the interconnection request.</p>		
PPL Supply Group	No	It may take longer since very few (if any) GOs are prepared to perform this type of work.
<p><b>Response:</b> Thank you for your comment. The drafting team believes it has built in the appropriate amount of time by giving a year in the implementation plan and then waiting to "activate" the standard until a Generator Owner has an executed Agreement to evaluate the reliability impact of the interconnection request.</p>		
BGE	Yes	This requirement is consistent with the initial time frame when FAC-003-1 was first implemented.
<p><b>Response:</b> Thank you for your comment.</p>		
Southern Company	Yes	However, we do not believe it is necessary to require a GO to have Facility connection requirements as we discuss in our response to Question 1.
<p><b>Response:</b> Thank you for your comment. Please see our response to your Question 1 comments above.</p>		
FirstEnergy Corp	Yes	The one year lead time is sufficient lead-time to notice the GOs of new expectations required under FAC-001-1.
<p><b>Response:</b> Thank you for your comment.</p>		
Northeast Power Coordinating	Yes	

Organization	Yes or No	Question 2 Comment
Council		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	
Electric Market Policy	Yes	
SERC Planning Standards Subcommittee	Yes	
Imperial Irrigation District (IID)	Yes	
Public Service Enterprise Group	Yes	
SPP Reliability Standards Development Team	Yes	
ACES Power Members	Yes	
Bonneville Power Administration	Yes	
EPSA	Yes	
PacifiCorp	Yes	
Arizona Public Service Company	Yes	

Organization	Yes or No	Question 2 Comment
Westar Energy	Yes	
Luminant Power	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Sempra Generation	Yes	
Tri-State Generation and Transmission, Inc.	Yes	
Xcel Energy	Yes	
Tacoma Power	Yes	
Duke Energy	Yes	
Constellation Power Generation	Yes	
Ameren	Yes	
Indeck Energy Services	Yes	
CHPD	Yes	
Independent Electricity System Operator	Yes	



Organization	Yes or No	Question 2 Comment
TransAlta Centralia Generation LLC	Yes	
Georgia Transmission Corporation		
Wisconsin Electric		
Utility Services, Inc.		
Exelom		
LG&E and KU Energy		
American Transmission Company		

**3. Taking into consideration that only one of the versions of FAC-003 will actually be implemented, a decision that will be made as the Project 2010-07 drafting team learns more about the status of Project 2007-07—Vegetation Management, do you support the proposed redline changes to FAC-003-X and FAC-003-3?**

**Summary Consideration:** The SDT thanks all individuals and groups who provided feedback. The majority of comments indicated support for the SDT’s changes to FAC-003-X and FAC-003-3, and the drafting team made additional changes, based on commenter feedback, where the team believes those changes add clarity.

Many commenters focused on the half-mile qualifier in FAC-003-X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: “...that extends greater than one mile beyond the fenced area of the generating station switchyard...” The drafting team believes that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, the team maintains that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.

One commenter caught typos in the Effective Dates sections of the standards, and those typos have been corrected.

Single commenters brought up minority issues, but the SDT found no justification for these issues. We address those minority issues in our responses to the specific comments below.

Organization	Yes or No	Question 3 Comment
American Transmission Company	No	<p>ATC does not support the changes for FAC-003-X, however, ATC does support FAC-003-3.</p> <p>FAC-003-X Concerns. The VRF and VSL tables do not correlate to the original FAC-003-1 levels of non-compliance section D.2. ATC believes that section D.2 should be rewritten to align with the already approved FAC-003-1.</p> <p>FAC-003-X Corrections- Applicability Section 4.3.1, sentence 3 - Transmission should not be capitalized.</p>

Organization	Yes or No	Question 3 Comment
		FAC-003-3 - No Concerns
<p><b>Response:</b> Thank you for your comment. The VSLs and VRFs in FAC-003-X were taken from already approved NERC projects to update all early versions of standards with VSLs and VRFs instead of levels of non-compliance. Any additional changes to those VSLs and VRFs would be beyond the scope of this drafting team. No change made.</p> <p>Applicability Section 4.3.1 no longer includes a capitalized version of Transmission (just a reference to the "Transmission Owner's Facility").</p>		
Public Service Enterprise Group	No	<p>FAC-003-X and FAC-003-3 both have similar "one half mile" language, the starting point for the one half mile is vague. In FAC-003-X, the language in 4.3.1 reads "Generator Owner that owns an overhead Facility that extends greater than one half mile beyond the fenced area of the switchyard, generating station or generating substation up to the point of interconnection with the Transmission system and ...". While we support the one half mile language, there are three possible starting points for the measurement of the one half mile: beyond the fenced area of (i) the switchyard, (ii) the generating station, or (iii) the generation substation. While a GO's fencing policy may differ between generation stations, the requirement to implement vegetation management should be clear. For clarity, while we believe that the language should retain flexibility with regards to "fencing" by the Generator Owner, it should be clear that the Generation Owner determines the starting point.</p> <p>Second, a Generator Owner's overhead Facility that is within the fence should explicitly not be applicable to the standard. Finally, we believe the language that refers to the "interconnection with the Transmission system" should be changed to "interconnection with a Transmission Owner's Facility. The reason is that the term "Transmission" which is defined in the NERC Glossary could be construed to include all of a Generator Owner's interconnection leads. (The definition is excerpted from the Glossary in our response to question 7) Therefore, we suggest that the language in 4.3.1 be modified as follows to make all of these points clear: A Generator Owner that owns an overhead Facility that extends greater than one half mile beyond the fenced area of either the generator switchyard, generating station or generating substation (as specified by the Generation Owner) up to the point of interconnection with</p>

Organization	Yes or No	Question 3 Comment
		<p>a Transmission Owner’s Facility and is operated 200 kV and above and any lower voltage lines designated by the RE as critical to the reliability of the electric system within the region is applicable to this standard.”</p>
<p><b>Response:</b> Thank you for your comment. The drafting team received many comments about the half-mile qualifier in FAC-003-X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: “...that extends greater than one mile beyond the fenced area of the generating station switchyard...” We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.</p> <p>The drafting team agrees that “interconnection with a Transmission Owner’s Facility” adds clarity. That change has been made.</p>		
<p>SPP Reliability Standards Development Team</p>	<p>No</p>	<p>In both FAC-003-3 and FAC-003-X it lists “greater than one half mile cutoff”. We would recommend that the distance cutoff be removed. We feel that overhead Facilities shouldn’t be treated any differently than any other. Also we would like to see these two sections in both standard proposals reflect similar language for 4.3.1.</p>
<p><b>Response:</b> Thank you for your comment. The drafting team received many comments about the half-mile qualifier in FAC-003-X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: “...that extends greater than one mile beyond the fenced area of the generating station switchyard...” We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.</p>		

Organization	Yes or No	Question 3 Comment
PPL Supply Group	No	<p>Version 3 (based on V2): Third Effective date appears to contain a typographical error.</p> <p>Version X (based on V1): Same as Version 3 comments.</p> <p>Please consider streamlining the section Background (Version 3).</p>
<p><b>Response:</b> Thank you for your comment. The typographical errors were corrected in both versions of the standard. Streamlining the Background section in Version 3 is not within the scope of this drafting team. No change made.</p>		
Westar Energy	No	<p>The language in the applicability section 4.3.1 in both FAC-003-3 and FAC-003-X states "extends greater than one half mile beyond..." We propose that the SDT consider removing the distance exclusion to be consistent with language for Transmission Owner Facilities and treat all overhead facilities the same.</p>
<p><b>Response:</b> Thank you for your comment. The drafting team received many comments about the half-mile qualifier in FAC-003-X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: "...that extends greater than one mile beyond the fenced area of the generating station switchyard..." We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.</p>		
Southern Company	No	<p>(1) We question whether R1 of FAC-003-3 would ever apply to a GO who owns transmission interconnection equipment. Can the SDT provide an example or two in the Guideline and Technical Basis section of the standard?</p> <p>(2) We recommend rearranging the language in R5 of FAC-003-3 to state, "The applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments when..." This places the "shall" at the beginning of the</p>

Organization	Yes or No	Question 3 Comment
		<p>requirement which is clearer and consistent with the structure of the other requirements.</p> <p>(3) We question why there are no VSLs assigned to R4. Should there be? What are the consequences if a Regional Entity does not comply?</p> <p>(4) There does not appear to be any coordination with the Vegetation Management Standard Drafting Team (VMSDT) concerning proposed modifications to the standard. The VMSDT should be consulted.</p>
<p><b>Response:</b> Thank you for your comment.</p> <p>(1) The SDT is not currently aware of specific examples where R1 would apply, but we do not see any reason to remove that reference, as it could apply in the future. If we removed it now, we'd create a reliability gap, but if we leave it in, no Generator Owner has to take action unless it has an IROL or WECC transfer path.</p> <p>(2) This change is beyond the scope of our drafting team. It is an issue that should have been addressed under Project 2007-07. We will submit the issue in a Suggestion Form to be added to NERC's Issues Database.</p> <p>(3) Because the Regional Entity is not a Functional Entity, it cannot be assigned penalties under NERC's Reliability Standards.</p> <p>(4) The Project 2007-07 Vegetation Management drafting team's latest draft standard has already passed ballot, so coordination with that team was no longer a possibility.</p>		
APS	No	Leave the GO out of both Standards proposed.
<p><b>Response:</b> Thank you for your comment. The drafting team and the majority of stakeholder commenters support making both FAC-001 and FAC-003 applicable to Generator Owners to ensure that all Generator Owner responsibilities at the generator interconnection Facility are covered under NERC Reliability Standards. No change made.</p>		
Indeck Energy Services	No	4.3.1.3 is a regional variation. The ROP doesn't permit members of one region to vote on regional requirements for another region. A separate regional standard will be required.
<p><b>Response:</b> Thank you for your comment. It is our understanding that any stakeholder can vote on regional requirements as long as they're in the body of the standard. This does not require a separate regional standard.</p>		

Organization	Yes or No	Question 3 Comment
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP believes there should be a relaxation in the vegetation management requirements for those interconnections which only serve as a radial link to the BES. Although we fully understand the importance of keeping vegetation away from high voltage lines, the one year period is much too frequent in our generator locations. The added documentation and other expenses simply do not justify the non-existent gain in reliability when vegetation in a locale (e.g.; desert) never reaches five feet above the ground. Consider limiting this exception to units below a certain MVA rating that are not critical to the BES - perhaps coupled with evidence that vegetative intrusions are highly unlikely.
<p><b>Response:</b> Thank you for your comment. We have attempted to set up a reasonable qualifier/balance with the new one mile designation and “stake in the ground” at the fenced line of the switchyard. Because of a perceived reliability gap at the interconnection between Generator Owner Facilities and Transmission Owner Facilities, we are doing our best to apply the same Transmission Owner vegetation management requirements to the Generator Owner. This issue you raise (with respect to the vegetation in certain locales) could possibly be applied to other entities besides the Generator Owner if it was technically justified, so the drafting team encourages you to submit a SAR suggesting this.</p>		
Notheast Power Coordinating Council	No	See comments in the following questions.
EPSA	Yes	<p>EPSA generally supports the SDT’s proposed redline changes to FAC-003-X and FAC-003-3 and SDT’s diligence in monitoring Project 2007-07. There is one distinction however that EPSA would like to bring to the SDT’s attention that could increase clarity. FAC-003-X and FAC-003-3 both have similar “one half mile” language, but the starting point for the one half mile can occur one of three ways.</p> <p>In FAC-003-X, the language in 4.3.1 reads “Generator Owner that owns an overhead Facility that extends greater than one half mile beyond the fenced area of the switchyard, generating station or generating substation up to the point of interconnection with the Transmission system and ...” Therefore, there are three possible starting points for the measurement of the one half mile: beyond the fenced area of (i) the switchyard, (ii) the generating station,</p>

Organization	Yes or No	Question 3 Comment
		<p>or (iii) the generation substation. While it would appear implicit that GO's would determine which of the three was used to make the determination that the GO determines the starting point.</p> <p>Another point for consideration is that a Generator Owner's overhead Facility that is within the fence should explicitly not be applicable to the standard. EPSA believes the language that refers to the "interconnection with the Transmission system" should be changed to "interconnection with a Transmission Owner's Facility. The reason is that the term "Transmission" which is defined in the NERC Glossary could be construed to include all of a Generator Owner's interconnection leads. Therefore, we suggest that the language in 4.3.1 be modified as follows to make all of these points clear: A Generator Owner that owns an overhead Facility that extends greater than one half mile beyond the fenced area of either the generator switchyard, generating station or generating substation (as specified by the Generation Owner) up to the point of interconnection with the Transmission Owner's Facility and is operated 200 kV and above and any lower voltage lines designated by the RE as critical to the reliability of the electric system within the region is applicable to this standard."</p>
<p><b>Response:</b> Thank you for your comment. The drafting team received many comments about the half-mile qualifier in FAC-003-X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: "...that extends greater than one mile beyond the fenced area of the generating station switchyard..." We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.</p> <p>The drafting team agrees that "interconnection with a Transmission Owner's Facility" adds clarity. That change has been made.</p>		



Organization	Yes or No	Question 3 Comment
BGE	Yes	As noted in Question-1 above.
<b>Response:</b> Thank you for your comment. See our response to Question 1.		
SERC OC Standards Review Group	Yes	
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	
Electric Market Policy	Yes	
SERC Planning Standards Subcommittee	Yes	
Imperial Irrigation District (IID)	Yes	
ACES Power Members	Yes	
Bonneville Power Administration	Yes	
PacifiCorp	Yes	
Arizona Public Service Company	Yes	
Luminant Power	Yes	

Organization	Yes or No	Question 3 Comment
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Sempra Generation	Yes	
Tri-State Generation and Transmission, Inc.	Yes	
Xcel Energy	Yes	
Georgia Transmission Corporation	Yes	
Exelom	Yes	
Duke Energy	Yes	
Constellation Power Generation	Yes	
Ameren	Yes	
CHPD	Yes	
Independent Electricity System Operator	Yes	
FirstEnergy Corp	Yes	
TransAlta Centralia	Yes	

Organization	Yes or No	Question 3 Comment
Generation LLC		
LG&E and KU Energy		
Manitoba Hydro		
Tacoma Power		
Wisconsin Electric		
Utility Services, Inc.		

4. The drafting team has added Generator Owners to the Applicability sections of FAC-003-X and FAC-003-3 with the qualifier that the included lines “extend greater than one half mile beyond the fenced area of the switchyard, generating station or generating substation up to the point of interconnection with the Transmission system.” The team received many comments about the need to define a distance rather than other measures for exclusion, and decided on the one half mile as a reasonable distance. Do you agree with this half-mile qualifier?

**Summary Consideration:** The SDT thanks all individuals and groups who provided feedback. The majority of comments indicated support for the SDT’s changes to FAC-003-X and FAC-003-3, and the drafting team has made additional changes, based on commenter feedback, where they think those changes add clarity.

The drafting team received many comments about the half-mile qualifier in FAC-003-X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: “...that extends greater than one mile beyond the fenced area of the generating station switchyard...” The SDT believes that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, the team maintains that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.

One commenter suggesting including the equivalent kilometer length in the qualifying language in the standard, and we have made that change.

Organization	Yes or No	Question 4 Comment
Northeast Power Coordinating Council	No	The qualifier should be similar to that specified in Part 4.2.4 of FAC-003-3: “This standard applies to overhead transmission lines identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence. “ Vegetation needing attention can exist within a half mile of a switchyard. Vegetation does not discriminate between Generation and Transmission Owners.

**Response:** Thank you for your comment. The drafting team received many comments about the half-mile qualifier in FAC-003-

Organization	Yes or No	Question 4 Comment
		<p>X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: "...that extends greater than one mile beyond the fenced area of the generating station switchyard..." We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.</p>
<p>SPP Reliability Standards Development Team</p>	<p>No</p>	<p>See comment above. We feel like there is no need for using a distance exclusion.</p>
		<p><b>Response:</b> Thank you for your comment. The drafting team received many comments about the half-mile qualifier in FAC-003-X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: "...that extends greater than one mile beyond the fenced area of the generating station switchyard..." We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.</p>
<p>PPL Supply Group</p>	<p>No</p>	<p>Version 3 (based on V2):Comments: Although the "one half mile" is much clearer than "two spans", what is the rationale for choosing ½ mile as opposed to another length such as 1 or 2 miles? Version X (based on V1): Same as Version 3 comments</p>
		<p><b>Response:</b> Thank you for your comment. The drafting team received many comments about the half-mile qualifier in FAC-003-X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: "...that extends greater than one mile beyond the fenced area of the generating station switchyard..." We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of</p>

Organization	Yes or No	Question 4 Comment
		the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.
Bonneville Power Administration	No	BPA believes that there needs to be a clear demarcation where Transmission Owner and Generator Owner responsibilities begin and end.
		<b>Response:</b> Thank you for your comment. The drafting team is operating under the assumption the Generator Owner’s responsibilities to its interconnection Facility up to the point of interconnection with the Transmission Owner’s Facility, and we have attempted to make that clear in our draft standards. We are considering changes to the definitions of Generator Owner and Generator Operator, or creation of new terms to provide additional clarity in the next steps of our project plan, pending Standards Committee approval.
Arizona Public Service Company	No	The generator should be responsible no matter the length from fence area to the point of interconnection.
		<b>Response:</b> Thank you for your comment. The drafting team received many comments about the half-mile qualifier in FAC-003-X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: “...that extends greater than one mile beyond the fenced area of the generating station switchyard...” We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.
Southern Company	No	We agree with a one-half mile line as being “within the Generator Owner’s line of sight and could be visually monitored for vegetation conditions on a routine basis.” However, we suggest that some generation interconnection Facilities greater than ½ mile in length could also fall within the GO’s line of sight or be constructed such that they should be considered for exemption. Thus, the Task Force should consider including exclusions for longer generator tie lines if

Organization	Yes or No	Question 4 Comment
		<p>the GO can provide sufficient justification. Examples of justifications could include (1) a clear line of sight, (2) pavement, gravel, or other non-vegetation covered path, or (3) routine monitoring is performed from a roadway parallel to the line, etc. Do not obviate any other transmission requirements such as the following (which are incorporate into the draft standard): i. Operated at 200kV or higher; or ii. Operated below 200kV and included in IROL; or iii. Operated below 200kV and inclusion in a Major WECC Transfer Path</p>
<p><b>Response:</b> Thank you for your comment. The drafting team received many comments about the half-mile qualifier in FAC-003-X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: "...that extends greater than one mile beyond the fenced area of the generating station switchyard..." We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.</p> <p>The issue you raise with respect to justification for further exclusions could possibly be applied to other entities besides the Generator Owner (assuming it was technically justified), so the drafting team encourages you to submit a SAR suggesting this.</p>		
APS	No	Leave GOs out of the standards.
<p><b>Response:</b> Thank you for your comment. The drafting team and the majority of stakeholder commenters support making both FAC-001 and FAC-003 applicable to Generator Owners to ensure that all Generator Owner responsibilities at the generator interconnection Facility are covered under NERC Reliability Standards. No change made.</p>		
Ingleside Cogeneration LP	No	<p>The SDT needs to clarify that the one-half mile distance is measured from the property line of the Generation Owner, i.e., an interconnection line that is in a ROW. In addition, the half mile qualifier makes sense only for those interconnections into critical generation facilities. See our response under Question #3.</p>

Organization	Yes or No	Question 4 Comment
<p><b>Response:</b> Thank you for your comment. The drafting team received many comments about the half-mile qualifier in FAC-003-X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: "...that extends greater than one mile beyond the fenced area of the generating station switchyard..." We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.</p>		
Wisconsin Electric	No	In addition to the "greater than one-half mile" criteria, we maintain there should also be an exclusion for lines up to one mile in length which are entirely on the Generator Owner's property.
<p><b>Response:</b> Thank you for your comment. The drafting team received many comments about the half-mile qualifier in FAC-003-X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: "...that extends greater than one mile beyond the fenced area of the generating station switchyard..." We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.</p>		
Ameren	No	(1)We do not agree there should be a ½ mile exemption. On what legitimate basis could we say the first ½ mile is not important? (2) There may be different usage of the term "point of interconnection" in the industry. We suggest the SDT to consider proposing a formal definition of this term.
<p><b>Response:</b> Thank you for your comment. The drafting team received many comments about the half-mile qualifier in FAC-003-X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others</p>		



Organization	Yes or No	Question 4 Comment
<p>found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: "...that extends greater than one mile beyond the fenced area of the generating station switchyard..." We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.</p> <p>The drafting team is considering proposing a formal definition of the term "point of interconnection," or other definitional changes to make the use of that term clearer.</p>		
Westar Energy	No	
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	<p>Although the NSRF agrees with the 1/2 mile criteria (see question 1); we believe the drafting team will have to develop additional justification for this criteria given FERC's recent orders, RC11-1 and RC11-2 (see question 6 for full FERC Order details). In these orders FERC "implies" that if the GO/GOP is responsible for a breaker operated at 100kV or higher the entity should be required to register as a TOP/TO. Therefore it appears FERC would not be inclined to provide any leeway based on distance from the substation. The SDT should note that the FERC Order points to this Project to "address matters involving reliability obligations at the interface of the transmission grid", which is foot note 58.</p>
<p><b>Response:</b> Thank you for your comment.</p>		
SERC Planning Standards Subcommittee	Yes	<p>However, we are concerned that there may be a reliability gap for locations where there is not a half-mile line-of-sight from the generation switchyard.</p>
<p><b>Response:</b> Thank you for your comment. The SDT believes these cases are limited enough that an exclusion within the standard is not necessary. If you believe it is, we encourage you submit to a <a href="#">Suggestion Form</a>.</p>		
EPSA	Yes	<p>EPSA appreciates the SDT proposing to use the approach that provides a</p>

Organization	Yes or No	Question 4 Comment
		specific distance for determining which GO Facility lead lines that FAC-003 should apply to. EPSA agrees that the half-mile qualifier provides a discrete parameter that will limit ambiguity in the Standard.
<b>Response:</b> Thank you for your comment.		
LG&E and KU Energy	Yes	Although the "one half mile" is much clearer than "two spans", what is the rationale for choosing ½ mile as opposed to another length such as 1 or 2 miles?
<b>Response:</b> Thank you for your comment. The drafting team received many comments about the half-mile qualifier in FAC-003-X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: "...that extends greater than one mile beyond the fenced area of the generating station switchyard..." We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.		
Independent Electricity System Operator	Yes	We generally agree with the proposed distance. However, we suggest that in Applicability Section 4.3.1 of the two draft standards, an equivalent kilometer value be inserted after the "one half mile".
<b>Response:</b> Thank you for your comment. We have added the equivalent kilometer value.		
SERC OC Standards Review Group	Yes	While we agree, we believe that a better explanation of "the fenced area of the switchyard, generating station or generating substation up to the point of interconnection with the Transmission system" should be included. One suggestion is to distinguish between a plant perimeter fence and an internal switchyard fence.
<b>Response:</b> Thank you for your comment. The drafting team received many comments about the half-mile qualifier in FAC-		

Organization	Yes or No	Question 4 Comment
<p>003-X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: "...that extends greater than one mile beyond the fenced area of the generating station switchyard..." We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.</p>		
BGE	Yes	1/2 mile is a distance that can generally be viewed from one location, e.g. the switchyard, and can be construed to present minimal risk since switchyards have a reasonably frequent personnel presence that could be expected to notice vegetation issues in the <1/2 mile area.
<p><b>Response:</b> Thank you for your comment.</p>		
Electric Market Policy	Yes	
Imperial Irrigation District (IID)	Yes	
Public Service Enterprise Group	Yes	
ACES Power Members	Yes	
PacifiCorp	Yes	
Luminant Power	Yes	
American Electric Power	Yes	

Organization	Yes or No	Question 4 Comment
Xcel Energy	Yes	
Sempra Generation	Yes	
Tri-State Generation and Transmission, Inc.	Yes	
BP Wind Energy North America Inc.	Yes	
Georgia Transmission Corporation	Yes	
Exelom	Yes	
FirstEnergy Corp	Yes	
TransAlta Centralia Generation LLC	Yes	
Duke Energy	Yes	
Indeck Energy Services	Yes	
Constellation Power Generation	Yes	
CHPD	Yes	
Utility Services, Inc.		
Manitoba Hydro		

<b>Organization</b>	<b>Yes or No</b>	<b>Question 4 Comment</b>
Tacoma Power		
American Transmission Company		

**5. Do you support the two year compliance timeframe for Generator Owners as included and explained in the Implementation Plans for FAC-003-X and FAC-003-3?**

**Summary Consideration:** The SDT thanks all individuals and groups who provided feedback. The vast majority of commenters supported the two-year compliance timeframe for Generator Owners as included and explained in the Implementation Plan. One commenter suggested that one year would be sufficient because most lines will be short, but the SDT pointed out that the distances of the lines can vary, and Generator Owners that have not been practicing any sort of vegetation management will need to hire new staff and develop a full vegetation management plan, which could take longer than the year given to Transmission Owners for implementation of FAC-003-1. No changes were made to the two-year compliance timeframe, although the team has modified FAC-003-3's implementation plan to account for a few different scenarios that could occur with respect to the filing of FAC-003-2 and FAC-003-3

Organization	Yes or No	Question 5 Comment
Ingleside Cogeneration LP	No	The two year compliance time frame makes sense only for those GOs who own interconnections into critical generation facilities. See our response under Question #3.
<p><b>Response:</b> Thank you for your comment. It is unclear whether you find the two year timeframe too long or too short, or if you believe that the standard should only apply to Generator Owners who own interconnections into critical generation facilities. No change made.</p> <p>Please see our response to your comments under Question 3 above.</p>		
APS	No	Leave GOs out of the standards.
<p><b>Response:</b> Thank you for your comment. The drafting team and the majority of stakeholder commenters support making both FAC-001 and FAC-003 applicable to Generator Owners to ensure that all Generator Owner responsibilities at the generator interconnection Facility are covered under NERC Reliability Standards. No change made.</p>		
Arizona Public Service Company	No	The generator should be able to be in compliance within one year since the distance of line miles is small.
<p><b>Response:</b> Thank you for your comment. The distances of the lines can vary, and Generator Owners that have not been practicing any sort of vegetation management will need to hire new staff and develop a full vegetation management plan, which could take</p>		

Organization	Yes or No	Question 5 Comment
longer than the year given to Transmission Owners for implementation of FAC-003-1. No change made.		
Northeast Power Coordinating Council	Yes	
SERC OC Standards Review Group	Yes	
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	
Electric Market Policy	Yes	
SERC Planning Standards Subcommittee	Yes	
Imperial Irrigation District (IID)	Yes	
Public Service Enterprise Group	Yes	
SPP Reliability Standards Development Team	Yes	
PPL Supply Group	Yes	
ACES Power Members	Yes	
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 5 Comment
EPSA	Yes	
PacifiCorp	Yes	
Westar Energy	Yes	
Southern Company	Yes	
Luminant Power	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Sempra Generation	Yes	
Tri-State Generation and Transmission, Inc.	Yes	
Xcel Energy	Yes	
Georgia Transmission Corporation	Yes	
BGE	Yes	No comment.
Exelom	Yes	
Wisconsin Electric	Yes	
Duke Energy	Yes	



Organization	Yes or No	Question 5 Comment
Constellation Power Generation	Yes	
Ameren	Yes	
Indeck Energy Services	Yes	
CHPD	Yes	
Independent Electricity System Operator	Yes	
FirstEnergy Corp	Yes	
TransAlta Centralia Generation LLC	Yes	
Utility Services, Inc.		
LG&E and KU Energy		
Tacoma Power		
Manitoba Hydro		
American Transmission Company		

6. In its background resource document, the drafting team lists the standards that it has not modified, and offers rationale for its decisions. Are there any reliability standards or requirements that you believe should apply to Generator Owners or Generator Operators that own and are responsible for the operation of an overhead Facility, that are not already applicable or have been proposed to be applicable (FAC-001 and FAC-003) by the Project 2010-07 drafting team? If so, please list them and offer an explanation as to why they should be applicable to that entity.

**Summary Consideration:** The SDT thanks all stakeholders for their feedback. The majority of commenters did not suggest the addition of any standards or requirements to the team’s scope of work, and a few commenters cautioned strongly against any additions. Some commenters suggested that the team consider including those standards and requirements listed in the June 2011 Cedar Creek and Milford FERC orders. The drafting team has considered the inclusion of the requirements listed in the Cedar Creek and Milford orders in the past, and has been revisiting them throughout our process. They have continued to conclude, with stakeholder support, that no additional substantive standard or requirement changes are necessary to achieve the goal of this project. With this posting, the drafting team has revisited those standards yet again and developed a comprehensive document and spreadsheet tracing their rationale (at every stage of the process) for not including additional standards or requirements. The team has elected to propose a slight clarifying change in PRC-004-2, but no changes to the applicability of that or any other standard.

While the SDT will not be adding standards at this time because they do not believe such additions are technically justified or justified by stakeholder comments, the team will be seeking some additional informal feedback from industry groups to ensure that their technical justifications are sound and supported by others outside of the drafting team. The team has posted their current draft rationale and technical justification documents on the project webpage with this posting. If you have any specific feedback on these documents, you are welcome to email [mallory.huggins@nerc.net](mailto:mallory.huggins@nerc.net).

Organization	Yes or No	Question 6 Comment
Manitoba Hydro	No	The direction of the background resource document gives special treatment to the Generator Owner in that it allows the Generator Owner TO status for a couple of standards (FAC-001 and FAC-003), but exempts the Generator Owner from many of the standards applicable to a TO. The NERC Functional Model defines the various functional entities. If a Generator Owner wants to be a TO, all the Requirements applicable to a TO should apply. There is no need to change specific Reliability Standards to allow the

Organization	Yes or No	Question 6 Comment
		Generator Owner to perform only selected TO functions.
<p><b>Response:</b> Thank you for your comment. The purpose of the drafting team is “To propose a set of changes to existing requirements and definitions, as well as additional requirements and definitions, that collectively adds significant clarity to Generator Owners and Generator Operators regarding their reliability standard obligations at the interface with the interconnected grid. This global strategy is proposed to expedite the closing of the reliability gap.” The SDT is applying select Transmission Owner standards to Generator Owners, not attempting to give them TO status.</p>		
Sempra Generation	No	No, Sempra Generation believes the Project 2010-07 Team has effectively indentified the Standards and Requirements that should apply to Generator Owners or Generator Operators that own, and are responsible for, the operation of an overhead Facility, that are not already applicable or have been proposed to be applicable.
<p><b>Response:</b> Thank you for your comment.</p>		
APS	No	Leave GOs and GOPs out of the FAC-001 and FAC-003 standards.
<p><b>Response:</b> Thank you for your comment. The drafting team and the majority of stakeholder commenters support making both FAC-001 and FAC-003 applicable to Generator Owners to ensure that all Generator Owner responsibilities at the generator interconnection Facility are covered under NERC Reliability Standards. No change made.</p>		
SERC OC Standards Review Group	No	
Electric Market Policy	No	
SERC Planning Standards Subcommittee	No	
Imperial Irrigation District (IID)	No	
SPP Reliability Standards	No	

Organization	Yes or No	Question 6 Comment
Development Team		
ACES Power Members	No	
EPSA	No	
PacifiCorp	No	
Arizona Public Service Company	No	
Westar Energy	No	
Luminant Power	No	
American Electric Power	No	
BP Wind Energy North America Inc.	No	
Tri-State Generation and Transmission, Inc.	No	
Xcel Energy	No	
Georgia Transmission Corporation	No	
BGE	No	No comment.
Exelom	No	

Organization	Yes or No	Question 6 Comment
Ingleside Cogeneration LP	No	
Wisconsin Electric	No	
Duke Energy	No	
Constellation Power Generation	No	
Ameren	No	
Indeck Energy Services	No	
CHPD	No	
Independent Electricity System Operator	No	
FirstEnergy Corp	No	
TransAlta Centralia Generation LLC	No	
Public Service Enterprise Group	Yes	<p>FERC's Cedar Creek and Milford order (issued on June 16, 2011 and that is posted at <a href="http://www.nerc.com/files/Order_Denying_Appeals_RC11-1_RC11-2_20110616.pdf">http://www.nerc.com/files/Order_Denying_Appeals_RC11-1_RC11-2_20110616.pdf</a>) listed several standards (in Paragraphs 71 and 87) that should be applicable to Cedar Creek and Milford, respectively. Because of this order, the drafting team should examine the listed standards and determine whether they are or are not applicable to Generator Owners or Generator Operators that own and are responsible for the operation of an overhead Facility. We emphasize that our recommendation takes no position on any legal issues regarding the referenced order.</p>
<p><b>Response:</b> Thank you for your comment. The drafting team has considered the inclusion of the requirements listed in the Cedar</p>		

Organization	Yes or No	Question 6 Comment
		<p>Creek and Milford orders in the past, and we have been revisiting them throughout our process. We continue to conclude, with stakeholder support, that no additional substantive standard or requirement changes are necessary to achieve the goal of this project. With this posting, the drafting team has revisited those standards yet again and developed a comprehensive document and spreadsheet tracing our rationale (at every stage of the process) for not including additional standards or requirements. We have elected to propose a slight clarifying change in PRC-004-2, but no changes to the applicability of that or any other standard. Please see the accompanying resource documents for more information.</p>
<p>Midwest Reliability Organization's NERC Standards Review Forum (NSRF)</p>	<p>Yes</p>	<p>In FERC order "Denying Appeals of Electric Reliability Organization Registration Determinations" dated June 16, 2011 (RC11-1 and RC11-2) FERC explicitly stated compliance GAPS existed with the following standards at a minimum: o FAC-011, Requirements R2, R2.1, R2.2. o PRC-001-1, Requirements R2, R2.2, R4; o PRC-004-1 Requirement R1; o TOP-004-2, Requirements R6, R6.1, R6.2, R6.3, R6.4; o PER-003-1, Requirements R1, R1.1, R1.2; o FAC-003-1, Requirements R1, R2; o TOP-001, Requirement R1 and o FAC-014-2, Requirement R2. When a GO/GOP owns transmission equipment but is not registered as a TO or TOP. The drafting team should explicitly address each of these the above requirements.</p>
<p><b>Response:</b> Thank you for your comment. The drafting team has considered the inclusion of the requirements listed in the Cedar Creek and Milford orders in the past, and we have been revisiting them throughout our process. We continue to conclude, with stakeholder support, that no additional substantive standard or requirement changes are necessary to achieve the goal of this project. With this posting, the drafting team has revisited those standards yet again and developed a comprehensive document and spreadsheet tracing our rationale (at every stage of the process) for not including additional standards or requirements. We have elected to propose a slight clarifying change in PRC-004-2, but no changes to the applicability of that or any other standard. Please see the accompanying resource documents for more information.</p>		
<p>Tacoma Power</p>	<p>Yes</p>	<p>Tacoma Power suggests that three standards be reconsidered for inclusion in this Project, to include the Generator Owner and/or Operator: EOP-005, more directly responsible for participation in restoration plans; PER-002, responsible for training; and VAR-001.</p>
<p><b>Response:</b> Thank you for your comment. We have considered the inclusion of additional standards and requirements throughout our process and we continue to conclude, with stakeholder support, that no additional substantive standard or requirement changes are necessary to achieve the goal of this project. With this posting, the drafting team has revisited those standards yet again and developed a comprehensive document and spreadsheet tracing our rationale (at every stage of the process) for not including</p>		

Organization	Yes or No	Question 6 Comment
<p>additional standards or requirements. We have elected to propose a slight clarifying change in PRC-004-2, but no changes to the applicability of that or any other standard. Please see the accompanying resource documents for more information. The SDT does not agree that VAR-001 should be applied to a GOP as VAR-002 @R2 already requires the GOP to “maintain the generator voltage or Reactive Power output (within applicable Facility Ratings) as directed by the Transmission Operator.” We believe this is sufficient in meeting the purpose of VAR-001.</p>		
Southern Company	Yes	Please see our Comments in response to Question 7.
Bonneville Power Administration	Yes	
PPL Supply Group		
Northeast Power Coordinating Council		
LG&E and KU Energy		
Utility Services, Inc.		
American Transmission Company		

**7. Do you have any other questions or concerns with the proposed standards or with the background resource document that have not been addressed? If yes, please explain.**

**Summary Consideration:** The SDT thanks all stakeholders who offered additional feedback in this section. Some comments revisited issues that had been addressed in other questions, and other comments introduced new minority concerns.

A few commenters suggested, again, the inclusion of definitions or additional standards within the scope of this project, and the SDT appreciates those comments, especially those which included detailed suggestions. While the team is not proposing any definition changes with this round of updated standard changes, they do plan to consider some definition changes or possibly new definitions to prevent future unnecessary registration of GOs and GOPs as TOs and TOPs and ensure that there are no possible reliability gaps. In the next steps of our project, we will consider putting forward definition-related changes for comment separately, following the procedure approved by the Standards Committee after its July 2011 meeting.

The SDT has also considered the inclusion of additional standards and requirements throughout our process and continues to conclude, with stakeholder support, that no additional substantive standard or requirement changes are necessary to achieve the goal of this project. With this posting, the drafting team has revisited those standards yet again and developed a comprehensive document and spreadsheet tracing our rationale (at every stage of the process) for not including additional standards or requirements. The team has elected to propose a slight clarifying change in PRC-004-2, but no changes to the applicability of that or any other standard. They have attempted to make our technical justifications much more robust and comprehensive than they were in the past, as suggested by stakeholders. Please see the accompanying resource documents (posted on the project webpage) for more information.

One commenter expressed concern about whether the SDT's work would be approved by regulators. The drafting team is doing everything we can to work with regulating entities to ensure that forced registrations no longer occur.

For most of the comments, the team made no changes and explained why:

One commenter suggested modifying the definition of Right-of-Way in the currently approved FAC-003-1 (our FAC-003-X). The team could not make any change because the definition proposed in FAC-003-3 has not been formally approved and, in general, modifications to the definition of ROW are outside the scope of our team.

One commenter suggested modifications to the format of the requirements in FAC-003-X, which the SDT determined to be outside its scope.



One commenter expressed concern about a Transmission Owner or Generator Owner having to comply with FAC-003 for a Facility that it did not own. The drafting team does not know why a Transmission Owner or Generator Owner would ever be required to provide evidence, documentation, notification, or inspection of vegetation management for Facilities not owned by that registered entity, except where explicitly agreed upon in a contract. In the absence of additional information to clarify this commenters concern, the SDT does not believe this needs to be addressed within the standard.

One commenter focused on FAC-001 and expressed concern about the “activation” point of the standard and the feasibility of any interconnection. The SDT reminded the commenter that “activation only occurs with an executed Agreement, and that in the past (for instance, 134 FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities.

One commenter wondered why only a select set of TO/TOP requirements were being applied to GOs/GOPs. The SDT directed this commenter to the goal of the team, which is to apply select Transmission Owner standards to Generator Owners, not to give them TO status.

Organization	Yes or No	Question 7 Comment
TransAlta Centralia Generation LLC	No	TransAlta Centralia Generation LLC (TransAlta) supports the recommendations put forward by the Project 2010-07 drafting team. The implementation of these recommendations will provide for much needed certainty for owners and operators of generation facilities.
<b>Response:</b> Thank you for your comment.		
SERC Planning Standards Subcommittee	No	The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
<b>Response:</b> Thank you for your comment.		
CHPD	No	
BP Wind Energy North	No	

Organization	Yes or No	Question 7 Comment
America Inc.		
Ameren	No	
Independent Electricity System Operator	No	
Tri-State Generation and Transmission, Inc.	No	
Electric Market Policy	No	
Georgia Transmission Corporation	No	
BGE	No	No comment.
Duke Energy	No	
SPP Reliability Standards Development Team	No	
Imperial Irrigation District (IID)	No	
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	No	
Xcel Energy	No	
Luminant Power	No	

Organization	Yes or No	Question 7 Comment
Wisconsin Electric	No	
ACES Power Members	No	
Arizona Public Service Company	No	
Westar Energy	No	
Bonneville Power Administration	No	
SERC OC Standards Review Group	No	
Northeast Power Coordinating Council	Yes	<p>Regarding the Right-of-Way definitions, the definition in FAC-003-3 is the better of the two. Suggest adding "and maintain" to the first sentence of the definition as follows: The corridor of land under a transmission line(s) needed to operate and maintain the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria. The term Right-of-Way goes beyond Transmission Vegetation Management, and that should be considered in the definition. How does Right-of-Way affect transmission facilities that are routed over bodies of water, or over valleys, highways, etc.? Right-of-Way in relation to underground facilities? The format of FAC-003-X should be made consistent with current NERC guidelines (i.e.--Parts of Requirements should not have R's in their numbering, should be 1.1, 1.2 etc.).</p>
<p><b>Response:</b> Thank you for your comment. It would be outside the scope of this team to modify the definition of Right-of-Way in the currently approved FAC-003-1 (our FAC-003-X), because the definition proposed in FAC-003-3 has not been formally approved and, in general, modifications to the definition of ROW are outside the scope of our team. No change made.</p>		

Organization	Yes or No	Question 7 Comment
		<p>With respect to the changes to the format of the requirements in FAC-003-X, while our drafting team is making changes to update the format of the standard where possible, we do not think it is appropriate to change the listing of the sub-requirements to parts. In earlier versions of standards, the sub-requirements were written as requirements (for instance, they have their own VSLs), and we do not believe it is appropriate within our scope to make that format and labeling change.</p>
<p>Public Service Enterprise Group</p>	<p>Yes</p>	<p>While we generally agree with the drafting team’s modifications to these standards, the team’s approach may not directly resolve the fundamental registration issue regarding a Generation Owner that only owns non-integrated interconnection transmission facilities. The non-integrated interconnection transmission facilities owned by a GO are part of the Bulk Electric System (BES) because they are part of BES generation facilities. The ownership of these non-integrated facilities should not require a GO to also register as a Transmission Owner. The draft team has proposed modifying two FAC standards that would apply to such GO-owned interconnection transmission facilities. These GO-owned interconnection transmission facilities are not, however, “integrated” transmission facilities, as the drafting team correctly points out in its background resource document. A proposed solution to the Generation Owner registration issue is discussed below.</p> <p>NERC’s Rules of Procedure (ROP) require entities to be registered in accordance with the definitions in the NERC Glossary of Terms Used in Reliability Standards (Glossary) and in accordance with the NERC Statement of Compliance Registry Criteria document. The Glossary has these definitions:</p> <ul style="list-style-type: none"> <li>o Generation Owner - Entity that owns and maintains generating units.</li> <li>o Transmission Owner - The entity that owns and maintains transmission facilities.</li> <li>o Facility - A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)</li> <li>o Transmission - An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.</li> </ul>

Organization	Yes or No	Question 7 Comment
		<p>o Transmission Service - Services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery</p> <p>The drafting team should create a new definition for the term “integrated transmission facilities” and include this new definition in the Glossary. This definition should then be use to modify the definition of Generation Owner so that registration will be clear. While the team chose not to create any new definitions, we believe the registration issue cannot be resolved without modifying the definition of “Generation Owner.”</p> <p>The following definition is proposed for Integrated Transmission Facilities in the NERC Glossary:</p> <p>o Integrated Transmission Facilities (ITF) - ITF are the Facilities that are a subpart of Transmission system that are capable of carrying the flows from multiple generator plants at different points of interconnection for delivery to customers or to other electric systems</p> <p>This proposed ITF definition builds upon FERC precedent in the Open Access Transmission Tariff (OATT) area. FERC has recognized that facilities that can carry flows from multiple supply points and deliver that power to either customers or other electric systems are proper facilities to include in an OATT and define the “Transmission System” for OATT purposes. The term “Transmission System” is an OATT-defined term that means “The facilities owned, controlled or operated by the Transmission Provider that are used to provide transmission service under Part II [Point-to-Point Transmission Service] and Part III [Network Integrated Transmission Service] of the Tariff.” Under FERC’s precedent, facilities such as generator step-up transformers and generator interconnecting transmission facilities have been excluded from the OATT; i.e., they are not facilities that provide Transmission Service because they cannot carry the flows from multiple supply points for delivery to customers or other electric system - their only use is to the Generation Owner. They perform two functions for a GO:</p> <ol style="list-style-type: none"> <li>1. They deliver power from the GO’s generators at a site to the OATT-defined Transmission System, and</li> <li>2. They deliver off-site power from the OATT-defined Transmission System to the generators at a site when the generators at a site are not operating.</li> </ol>

Organization	Yes or No	Question 7 Comment
		<p>While building on FERC OATT precedent, the proposed definition of “Integrated Transmission Facilities” does not require an applicable Transmission Service tariff to identify those facilities. Integrated Transmission Facilities are simply defined as those that capable of carrying flows from multiple supply points for delivery to customers or to other electric systems. Using the ITF definition, the definition of Generation Owner could be modified as follows:</p> <ul style="list-style-type: none"> <li>o Generation Owner - Entity that owns and maintains generating units but which does not own or maintain Integrated Transmission Facilities.</li> </ul>
<p><b>Response:</b> Thank you for your comment. We appreciate the detailed suggestions. While we are not proposing any definition changes with this round of updated standard changes, we do plan to consider some definition changes or possibly new definitions to prevent future registration and ensure that there are no possible gaps. In the next steps of our project, we will consider putting forward definition-related changes for comment separately, as is now allowed by the Standards Committee after its July 2011 meeting.</p>		
EPSA	Yes	<p>EPSA can appreciate the SDT’s decision that it not propose new defined terms for the NERC Glossary. The SDT bases the decision on outreach meetings with NERC, regional compliance managers and industry organizations. EPSA supports outreach but still believes that the SDT should propose definitions for the NERC Glossary. The definitions can serve as a basis for the outreach meetings while also further limiting reliability gaps - real or perceived. Much as EPSA expressed in its White Paper comments there is still a need for a definition for generator interconnection facilities. In addition, because integrated transmission facility has also played a big part in the cases that have prompted the need for Project 2010-07 the drafting team should propose a glossary change for that definition as well. A definition for generation interconnection facilities is necessary in Project 2010-07 Standard so that the interface between generators and transmission system can be clearly established and any ambiguities about reliability responsibilities for GOs &amp; GOPs and TO &amp; TOPs can be eliminated.</p> <p>EPSA recommended the definitions from the Ad-Hoc Group Report could be used for incorporating the Generator Interconnection Facility into the standard:</p> <ul style="list-style-type: none"> <li>Generator Interconnection Facility - Sole-use facility for the purpose of connecting the generating unit(s) to the transmission grid. In this regard, the sole-use facility</li> </ul>

Organization	Yes or No	Question 7 Comment
		<p>only transmits power associated with the interconnecting generator, whether delivered to the grid or delivered to the generator for station service or auxiliary load, or delivered to meet cogeneration load requirements.</p> <p>Generator Interconnection Operational Interface - Location at which operating responsibility for the Generator Interconnection Facility changes between the Transmission Operator and the Generator Operator.</p> <p>These definitions were developed with due consideration for varying configurations, outages, and generators materiality to the BES. The Facility definition defines the purpose of the facility, while the Generator Interconnection Operational Interface definition provides the functional lines of demarcation between the GO and the TO. The definitions were developed based on the purpose of generator interconnection facilities, their usage and how their usage differs from transmission facilities that comprise the interconnected grid. Similar to EPSA's assertions on the White Paper competitive suppliers believe this is a sound basis for distinguishing BES facilities. EPSA also suggests that the SDT include the following proposed definition for Integrated Transmission Facilities for inclusion in the NERC Glossary:</p> <p style="padding-left: 40px;">Integrated Transmission Facilities (ITF) - ITF are the Facilities that are a subpart of Transmission system that are capable of carrying the flows from multiple generator plants at different points of interconnection for delivery to customers, or to other electric systems.</p> <p>This proposed ITF definition builds upon Commission precedent in the Open Access Transmission Tariff (OATT) area. FERC has recognized that facilities that can carry flows from multiple supply points and deliver that power to either customers or other electric systems are proper facilities to include in an OATT and define the "Transmission System" for OATT purposes. The term "Transmission System" is an OATT-defined term that means "The facilities owned, controlled or operated by the Transmission Provider that are used to provide transmission service under Part II [Point-to-Point Transmission Service] and Part III [Network Integrated Transmission Service] of the Tariff." Under Commission precedent, facilities such as generator step-up transformers and generator interconnecting transmission facilities have been excluded from the OATT; i.e., they are not facilities that provide Transmission Service because they cannot carry the flows from multiple supply points for delivery to customers or other electric system - their</p>

Organization	Yes or No	Question 7 Comment
		<p>only use is to the GO and perform two functions:</p> <ol style="list-style-type: none"> <li>1. They deliver power from the GO's generators at a site to the OATT-defined Transmission System, and</li> <li>2. They deliver off-site power from the OATT-defined Transmission System to the generators at a site when the generators at a site are not operating.</li> </ol> <p>While building on FERC OATT precedent, the proposed definition of "Integrated Transmission Facilities" does not require an applicable Transmission Service tariff to identify those facilities. Integrated Transmission Facilities are simply defined as those that capable of carrying flows from multiple supply points for delivery to customers or to other electric systems. Using the ITF definition, the definition of Generation Owner could be modified as follows:</p> <p style="padding-left: 40px;">Generation Owner - The Entity that owns and maintains generating units but which does not own or maintain Integrated Transmission Facilities.</p> <p>EPSA encourages the Project 2010-07 SDT to consider fitting the above definitions into the current proposal for inclusion in the NERC Glossary. Therefore, EPSA respectfully requests that the SDT for Project 2010-07 consider the all the recommendations made herein to the seven questions.</p>
<p><b>Response:</b> Thank you for your comment. We appreciate the detailed suggestions. While we are not proposing any definition changes with this round of updated standard changes, we do plan to propose some definition changes or possibly new definitions to prevent registration and ensure that there are no possible gaps. In the next steps of our project, we will consider putting forward definition-related changes for comment separately, as is now allowed by the Standards Committee after its July 2011 meeting</p>		
PacifiCorp	Yes	<p>PacifiCorp believes the Standards Drafting Team should clarify the Transmission Owner and/or the Generator Owner are not required to provide evidence, documentation, notification, or inspection of vegetation management for facilities not owned by the Transmission Owner and/or the Generator Owner.</p>
<p><b>Response:</b> Thank you for your comment. The drafting team does not know why a Transmission Owner or Generator Owner would ever be required to provide evidence, documentation, notification, or inspection of vegetation management for Facilities not owned by that registered entity, except where explicitly agreed upon in a contract. We do not believe this needs to be addressed within the</p>		



Organization	Yes or No	Question 7 Comment
standard. No change made.		
Southern Company	Yes	<p>(1) The SDT needs to review the June 16, 2011 FERC Order on Cedar Creek and Milford and factor this into the equation. The FERC Order concludes that the Cedar Creek and Milford entities must register as a TO and TOP. In addition to FAC-003, the Cedar Creek and Milford order lists the following standards and requirements that apply to these entities as a TO/TOP:</p> <ul style="list-style-type: none"> <li>o PER-003-1, R1, R1.1, R1.2 (requiring NERC-certified transmission operators);</li> <li>o PRC-001-1, R2, R2.2, R4, R6 (notification of relay or equipment failures);</li> <li>o PRC-004-1, R1 (analyzing protection system misoperations);</li> <li>o FAC-014-2, R2 (establishment of system operating limits);</li> <li>o TOP-001, R1 (authority to take actions to alleviate operating emergencies);</li> <li>o TOP-004-2, R6, R6.1, R6.2, R6.3, R6.4 (establishment of formal policies to address voltage levels, planned outages, switching, Interconnection Reliability Operating Limits, and System Operating Limits).</li> </ul> <p>The SDT needs to address these specific requirements in sufficient detail by either revising the Project 2010-07 Background Resource Document or proposing revisions to these standards to address any reliability gaps. For example, we recommend, as a minimum, that the Background Resource Document discussion under PRC-001-1 be revised to state (underlined text added), "Generator Operators and the scope of protection equipment for generation interconnection Facilities are already appropriately accounted for in this standard in requirements R1, R2, R3, and R5." Please note that this statement, even with our proposed revision, conflicts with the FERC Order on Cedar Creek and Milford, Paragraphs 64, 65, and 78 where FERC states that Cedar Creek and Milford must register as a TO and TOP to ensure the protection system coordination requirements in R2 and R4 of PRC-001 are met. Thus, the discussion for PRC-001-1 in the Project 2010-07 Background Resource Document needs additional language to demonstrate adequacy of the GO requirements in order to prevent GOs that own generation interconnection Facilities from having to register as a TO and TOP.</p> <p>(2) In addition, we believe the SDT should add supporting discussion to the</p>

Organization	Yes or No	Question 7 Comment
		<p>Background Resource Document to explain why the following standards adequately cover GO/GOP requirements at the Transmission Interface: PRC-004-2, PRC-005-1, PRC-023-1. For example, the Background Resource Document could state that PRC-023-1 Section A.4 Applicability already includes, "4.2. Generator Owners with load-responsive phase protection systems as described in Attachment A, applied to facilities defined in 4.1.1 through 4.1.4."</p> <p>(3) Furthermore, FERC's analysis in the Cedar Creek and Milford order suggests that reliability gaps will occur if certain entities are not registered as TO/TOP. The GRTI SAR DT should assess why its findings are different from the Commission's findings. By way of background, the GRTI SAR DT provides that its own assessment of the GOTO Ad Hoc Group Final Report concludes with a belief that there are only two standards requiring modifications to address reliability gaps - FAC-001 and FAC-003 (Background Resource Document, page 3). FERC will most likely require that NERC clearly demonstrate and provide technical support for the position that GO's only need to comply with FAC-001 and FAC-003 and not the other standards noted by FERC. The Background Resource Document does not appear to provide adequate technical support for the GRTI SAR DT position. Therefore, the GRTI SAR DT should develop that technical support in preparation for the filing of these revised standards at FERC.</p>
<p><b>Response:</b> Thank you for your comment. We have considered the inclusion of additional standards and requirements throughout our process and we continue to conclude, with stakeholder support, that no additional substantive standard or requirement changes are necessary to achieve the goal of this project. With this posting, the drafting team has revisited those standards yet again and developed a comprehensive document and spreadsheet tracing our rationale (at every stage of the process) for not including additional standards or requirements. We have elected to propose a slight clarifying change in PRC-004-2, but no changes to the applicability of that or any other standard. We have attempted to make our technical justifications much more robust and comprehensive than they were in the past, as you suggest. Please see the accompanying resource documents for more information.</p>		
APS	Yes	Leave GOs out of the standards, because it just adds more regulation and reporting requirements not needed.
<p><b>Response:</b> Thank you for your comment. The drafting team and the majority of stakeholder commenters support making both FAC-001 and FAC-003 applicable to Generator Owners to ensure that all Generator Owner responsibilities at the generator interconnection Facility are covered under NERC Reliability Standards. No change made.</p>		

Organization	Yes or No	Question 7 Comment
Sempra Generation	Yes	When implemented, the recommendations of the Project 2010-07 Team go a long way toward providing the regulatory and compliance certainty needed by generators who own or operate Generator Interconnection Facilities. NERC is encouraged to provide these industry-supported amendments to the NERC Board of Trustees in the near future. Sempra Generation also supports the comments, being concurrently filed, of the Electric Power Supply Association (EPSA).
<b>Response:</b> Thank you for your comment.		
Exelon	Yes	FAC-001-1. Exelon has generating stations that have the Main Power Transformer (MPT) disconnect as the point of demarcation. The station owns the short leads from the MPT disconnect back to the generator and the applicable TO owns from the MPT disconnect up to and including the switchyard. It is not practical for another entity to request to interconnect to the MPT disconnect nor should it be allowed. The SDT should consider verbiage to the standard that does not allow requests to interconnect to a MPT disconnect. 2. Exelon is having difficulty determining how this standard would apply to GOs and how GOs would implement the standard; suggest that examples be provided in an implementation document specifically showing where and how this standard would apply.
<p><b>Response:</b> Thank you for your comment.</p> <p>(1) FAC-001-1 would not be “activated” simply with another entity’s request to interconnect. The standard is “activated” only with an executed Agreement to evaluate the reliability impact of interconnection. If another entity cannot interconnect to the MPT, the process should not get to the point of an executed Agreement and thus this standard would never apply.</p> <p>(2) In the past (for instance, 134 FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities, and the drafting team thinks it is important to clarify the responsibilities related to such a request in NERC’s Reliability Standards by including applicable Generator Owners in FAC-001-1. We have documented our technical justification in an accompanying resource document and encourage you to review it.</p>		
Ingleside Cogeneration LP	Yes	There is a fundamental issue related to the interconnection of generation and distribution facilities into the transmission grid. There is a myriad of complex architectures which make the designation of ownership and operational responsibilities

Organization	Yes or No	Question 7 Comment
		<p>unclear in both cases. Both this team’s efforts and those by the project team redefining the extent of the BES have run into this issue.</p> <p>Ingleside Cogeneration LP recognizes that the effort to properly assign reliability responsibilities in these gray-area connections is difficult. However, pushing the issue back to the GO/GOP by looking for them to jointly determine responsibilities with adjacent entities will create every conceivable arrangement possible.</p> <p>It seems like it should be possible to address a handful of common interconnection configurations at the start. As knowledge builds, perhaps other architectures could be added. This seems to be the direction that the project team redefining the extent of the BES is heading.</p> <p>Lastly, we need some assurance that regulators will work with us as we go down this path. Right now, the feeling is that they will continue to use forced registrations as a hammer - which may render moot this team’s efforts anyways.</p>
<p><b>Response:</b> Thank you for your comment.</p> <p>The drafting team is doing its best to coordinate with regulators to ensure that forced registrations no longer occur. While we can never be sure exactly what decision the regulators will make, our intent is to make changes through this project that prevent any future forced registrations. We have encouraged regulators to provide formal comments if they believe our changes are not going to close the gap. While there can be similarities, the SDT believes that each interconnection agreement is different. The SDT believes that each party to such agreement should have identified its ownership and operational responsibilities. If there is uncertainty as to ownership of operational responsibility of a Facility used to interconnect a generator, the respective GO/GOPs and TO/TOPs should be addressing these. Resolving these uncertainties can only occur between the affected parties.</p>		
Manitoba Hydro	Yes	<p>The direction of the background resource document gives special treatment to the Generator Owner in that it allows the Generator Owner TO status for a couple of standards (FAC-001 and FAC-003), but exempts the Generator Owner from many of the standards applicable to a TO. A Generator Owner that owns BES transmission should be held accountable for the specific Requirements and Reliability Standards applicable to the TO and Transmission Operator functions. If no other entity assumes accountability for these specific Requirements and Reliability Standards on the</p>

Organization	Yes or No	Question 7 Comment
		<p>Generator Owner BES transmission (for example system operation, protection and communication), there will be a reliability gap. Improper operation, coordination and protection of the Generator Owner BES transmission could have an impact on reliability.</p>
<p><b>Response:</b> Thank you for your comment. The purpose of the drafting team is “To propose a set of changes to existing requirements and definitions, as well as additional requirements and definitions, that collectively adds significant clarity to Generator Owners and Generator Operators regarding their reliability standard obligations at the interface with the interconnected grid. This global strategy is proposed to expedite the closing of the reliability gap.” The SDT is applying select Transmission Owner standards to Generator Owners, not attempting to give them TO status. The SDT believes that each interconnection agreement is different. The SDT believes that each party to such agreement should have identified its ownership and operational responsibilities. If there is uncertainty as to ownership of operational responsibility of a Facility used to interconnect a generator, the respective GO/GOPs and TO/TOPs should be addressing these. Resolving these uncertainties can only occur between the affected parties.</p>		
<p>Constellation Power Generation</p>	<p>Yes</p>	<p>Constellation appreciates and supports the work of the standard drafting team. We recognize the significant time invested by technical experts from industry to consider the appropriate application of reliability standards to address concerns raised about coverage of transmission at the generator interface. The recent FERC Order concerning Cedar Creek and Milford wind suggested that the list of applicable standards needing revision should go beyond FAC-001 and FAC-003.</p> <p>We appreciate the discussion and concerns raised by FERC in the order; however, the discussion is limited by failing to consider these issues in light of the full package of existing standards. Below is a look at the FERC suggested standards and how they intersect with other standards:</p> <ul style="list-style-type: none"> <li>o PRC-001-1, Requirements R2, R2.2, R4; FERC expressed concern that certain protection system components may not be well coordinated with the RC. However, the same standard (PRC-1) addresses this issue by requiring all GOs to ensure coordination of their protection system with interconnected parties. Further, FAC-002 requires that all new facilities undergo reviews by the TOP, BA, etc.</li> <li>o PRC-004-1 Requirement R1; FERC expressed concern that certain protection system components may not be analyzed for misoperations. However, the same standard (PRC-4) addresses this issue by requiring all GOs to ensure that they</li> </ul>

Organization	Yes or No	Question 7 Comment
		<p>analyze all misoperations on their protection system which would include the protection of the tie line.</p> <ul style="list-style-type: none"> <li>o TOP-004-2, Requirements R6, R6.1, R6.2, R6.3, R6.4; FERC expressed concern that coordination may be lacking between a GO and a TO with regards to the generator tie line. However, TOP standards applicable to GOs address this issue by requiring all GOs to coordinate all maintenance and emergency outages (both forced and planned) with all applicable interconnected parties. Further, all ISO procedures require the same of GOs.</li> <li>o PER-003-1, Requirements R1, R1.1, R1.2; FERC expressed concern that certain generator operators are responsible for the real time operation of the interconnected BES without being NERC certified operators, potentially causing a reliability gap. Generator Operators do not monitor and control the BES, they control and monitor generators that it operates and relays information to other operating entities. Therefore, NERC certification is not required.</li> <li>o FAC-003-1, Requirements R1, R2; FERC and the drafting team seem aligned in the need to revise this standard and the revision proposal includes such a revision.</li> <li>o TOP-001, Requirement R1; FERC expressed concern that certain tie lines may not be required to operate in such a way as to alleviate operational emergencies. However, IRO and TOP standards applicable to GOs address this issue by requiring all GOs to operate as directed by their TOP, BA, or RC as directed and must render emergency assistance.</li> <li>o FAC-014-2, Requirement R2; FERC expressed concern that certain tie lines may have a rating based on a methodology that may not be consistent with the methodology used by the RC. However, standards FAC-8 and FAC-9 address this issue by requiring all GOs to develop a methodology to rate all equipment, and that the RC has the authority to challenge the GO on that methodology. The onus is on the GO to either change their methodology and rating accordingly, or provide a technical justification as to why they cannot adopt the changes. Further, a generator will never be limited by its tie line, as a generator's profits are directly tied to its output. Therefore no generator would limit its facility to the</li> </ul>

Organization	Yes or No	Question 7 Comment
		equipment that is delivering that output.
<p><b>Response:</b> Thank you for your comment. The drafting team has considered the inclusion of the requirements listed in the Cedar Creek and Milford orders in the past, and we have been revisiting them throughout our process. We continue to conclude, with stakeholder support, that no additional substantive standard or requirement changes are necessary to achieve the goal of this project. With this posting, the drafting team has revisited those standards yet again and developed a comprehensive document and spreadsheet tracing our rationale (at every stage of the process) for not including additional standards or requirements. We appreciate the rationale you have included within your comment, and where we agree, we have incorporated it into our own.</p> <p>We have elected to propose a slight clarifying change in PRC-004-2, but no changes to the applicability of that or any other standard. Please see the accompanying resource documents for more information.</p>		
Utility Services, Inc.	Yes	<p>In one of the supporting documents for the upcoming comments, the GO/TO group included the following statement in support for the rationale on FAC-001. In its first posting for informal comment, the drafting team set the “trigger” for the application of FAC-001 as the receipt of a request for interconnection. Many commenters disagreed with this approach and suggested that the “trigger” be based upon “the intent or obligation” to interconnect a new Facility to an existing interconnecting Facility that is owned by a generator. Accordingly, the drafting team has proposed language to address this concern. The intent of this modified language is to start the compliance clock at such time as the Generator Owner executes an Agreement to perform the reliability assessment required in FAC-002-1. This step should occur whether the generator voluntarily agrees to the interconnection request or is compelled by a regulatory body to do so. In either case, we expect the Generator Owner and the requestor to execute some form of Agreement. We intentionally excluded a specific reference to the form of Agreement (such as a feasibility study) in deference to comments that we should avoid comingling of commercial and reliability aspects in reliability standards.</p> <p>I wonder about whether or not this can work timing-wise. It says the compliance clock starts with the agreement to perform the reliability assessment for FAC-002. The FAC-001 requirements outline the need for a registered entity to document, maintain, and publish facility connections requirements in order to be compliant. If the clock starts at the agreement for the assessment, does that mean that you then document, maintain, and publish the connection requirements? Don’t the connection requirements usually</p>



Organization	Yes or No	Question 7 Comment
		<p>outline the terms for the “agreement for the assessment”? I am not sure that I understand the timing sequence in order to be compliant to the standard. I would think that the agreement needs to be in place at the time of the effective date of the standard, not upon an application.</p>
<p><b>Response:</b> Thank you for your comment. We have provided a detailed explanation of how this process might look in the accompanying FAC-001-1 technical justification. Please refer to that for more information.</p>		
<p>FirstEnergy Corp</p>	<p>Yes</p>	<p>The June 16, 2011 FERC Order denying the appeals of two wind generating facilities- Cedar Creek and Milford - of the NERC determinations that Cedar Creek and Milford must each be registered as a transmission owner and transmission operator on the NERC Compliance Registry complicates the GO-TO drafting team’s work. However, the issues may be distinct and different in the end. The existing GO-TO team’s work product defines new reliability expectations for a generator owner regardless of whether or not the same entity is also being required to have a TO-TOP “light” compliance registration. In the Order, FERC describes what it believes are an appropriate limited set of TO-TOP requirements when a TO-TOP “light” registrations is deemed warranted for a traditional generation owner. The drafting team should describe what, if any, impact the FERC June 16 Order is having on its work scope.</p> <p>One minor comment for the background resource document. On page one, the last sentence of the 1st paragraph which currently reads “ ... appropriate level of reliability for the BES.” Consider changing to read “ ... Adequate Level of Reliability for the BES.” And, include a footnote directing the reader to NERC’s definition/paper describing ALR. The later references to “adequate level of reliability” within the document (i.e. page 2, 2nd paragraph could then be reduced to the acronym ALR.</p>
<p><b>Response:</b> Thank you for your comment. The drafting team has considered the inclusion of the requirements listed in the Cedar Creek and Milford orders in the past, and we have been revisiting them throughout our process. We continue to conclude, with stakeholder support, that no additional substantive standard or requirement changes are necessary to achieve the goal of this project. With this posting, the drafting team has revisited those standards yet again and developed a comprehensive document and spreadsheet tracing our rationale (at every stage of the process) for not including additional standards or requirements.</p> <p>Thank you for pointing out the opportunity to use the term “Adequate Level of Reliability.” Because NERC has appointed a task force to explore whether that definition of Adequate Level of Reliability needs to be changed, we are avoiding references to it in our latest</p>		



Organization	Yes or No	Question 7 Comment
resource document.		
PPL Supply Group	Yes	
American Wind Energy Association		<p>The American Wind Energy Association (AWEA) appreciates the opportunity to submit these formal comments on the NERC Project 2010-07. AWEA supports the general direction indicated by both the Generator Requirements at the Transmission Interface Ad Hoc Group (GOTO Ad Hoc Group), and the Project 2010-07 Standards Development Team (SDT). We agree with the sentiments from both groups that a Generator Owner (GO) or Generator Operator (GOP) that also owns or operates a generator interconnection facility (GIF), should not be required to register as a Transmission Owner (TO) and/or Transmission Operator (TOP) strictly because they own or operate the GIF. We also agree that requiring these GOs or GOPs to comply with all the TO/TOP standards would have little effect on or benefits to reliability of the Bulk Electric System.</p> <p>AWEA supports the aim of these groups to address any reliability gap that may exist with regard to GIFs by considering such facilities as part of the generating facility, and therefore also subject to the GO/GOP standards. AWEA also supports the approach of identifying a limited number of TO/TOP standards, such as FAC-001 and FAC-003, which should also apply to GIFs. We would be concerned, however, if additional requirements were added beyond these two, without serious consideration by the SDT and additional industry experts. The recent FERC order on the required registration as TOs and TOPs of two generator interconnection facilities may raise some question about the direction that the GO/TO and the SDT have taken so far on this topic. AWEA urges NERC and the SDT to use caution in considering any additional standards to apply to GIFs as the current approach of the GO/TO and SDT efforts have been generally supported. Consideration of any addition standards with respect to GIFs should be done on a standard-by-standard basis, reviewing the applicability of each standard as well as the impact on the reliability of the Bulk Electric System.</p>
<p><b>Response:</b> Thank you for your comment. The drafting team has considered the inclusion of additional standards and requirements in the past, and we have been revisiting them throughout our process. We continue to conclude, with stakeholder support, that no</p>		

Organization	Yes or No	Question 7 Comment
<p>additional substantive standard or requirement changes are necessary to achieve the goal of this project. With this posting, the drafting team has revisited those standards yet again and developed a comprehensive document and spreadsheet tracing our rationale (at every stage of the process) for not including additional standards or requirements.</p>		
<p>Cogeneration Association of California</p>		<p>The resolution of this issue regarding generator interconnection facilities should compel a certain result in determining how to classify and register generator tie-lines. Under the current standards, NERC is compelled to register owners with generator tie-lines as transmission owners. FERC has affirmed this. The changes to the standards should be such that NERC and FERC are compelled to consider the tie-lines as part of the generator facilities. The current proposal from this task force does not achieve that result. While the proposal does make very appropriate changes to certain reliability standards, it does not change the basic definition of the Bulk Electric System or change NERC's <i>Statement of Compliance Registry Criteria</i>, to determine how tie-lines are classified. Even though the relevant reliability standards would be changed so that they are also applicable to generator facilities, NERC and the regional entities will continue to apply the same definition and criteria and can continue to classify the tie-lines as Transmission.</p> <p>The solution is to change the BES definition and NERC <i>Statement</i> as well as changing the applicability of the relevant reliability standards. The background resource document from this group suggests that a change in the BES definition was part of the overall solution, but the Project 2010-17 team did not address this in its proposed definition. The concept paper from the 2010-17 group does include "generator interconnection line leads," but the formal definition paper does not.</p> <p>This project group should include in its formal proposal a change to the definition of BES, including generator interconnection facilities within the definition of generation.</p>
<p><b>Response:</b> Thank you for your comment. While we are not proposing any definition changes with this round of updated standard changes, we do plan to propose some definition changes or possibly new definitions to prevent registration and ensure that there are no possible gaps. In the next steps of our project, we will consider putting forward definition-related changes for comment separately, as is now allowed by the Standards Committee after its July 2011 meeting. Although this drafting team cannot itself make changes to the Statement of Compliance Registry Criteria, our hope is that modifications to definitions would provide the language and the impetus to make those Registry Criteria changes.</p>		

Organization	Yes or No	Question 7 Comment
<p>While the Project 2010-07 SDT coordinated with the Project 2010-17 BES SDT very early on, the Project 2010-17 SDT elected not to include any reference to generator interconnection Facilities within the definition of generation. We will consider making further suggestions during future comment periods, and you should do the same.</p>		
American Electric Power		
Tacoma Power		
Indeck Energy Services		
LG&E and KU Energy		
American Transmission Company		

END OF REPORT

# Consideration of Comments

## Generator Requirements at the Transmission Interface Project 2010-07

The Generator Requirements at the Transmission Interface Drafting Team thanks all commenters who submitted comments for Project 2010-07—Generator Requirements at the Transmission Interface. These standards were posted for a 45-day public comment period from October 5, 2011 through November 18, 2011. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 40 sets of comments, including comments from 123 different people from approximately 86 companies representing all 10 of the Industry Segments as shown in the table on the following pages.

Based on stakeholder comments, the SDT made minor changes to FAC-001-1, FAC-003-X, FAC-003-3, and PRC-004-2.1. The standards will proceed to recirculation ballot.

In FAC-001-1, the SDT corrected a typo in the Applicability section 4.2.1 to change “within” to “with”; corrected a typo in the VSLs for R3 to ensure that parts 3.1.1 through 3.1.16 were referenced, rather than just 3.1.1 through 3.1.6; and changed references to “Transmission System” to “interconnected Transmission systems” to ensure consistency with the language elsewhere in the standard and in FAC-002-1.

In FAC-003-X and FAC-003-3, the SDT added a clarifying reference to line of sight in the GO exemption in section 4.3.1. of both versions; corrected a typo in 4.3.1.2 of FAC-003-3; and changed “RE” to “Regional Entity” in 4.3.1 of FAC-003-X.

As it discusses in the document titled “[Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface](#),” the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.

To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: “Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”

With this reference, the SDT simply seeks to clarify the exception language based on the intent that has been agreed upon by the stakeholder body. In its [Consideration of Comments report](#) from the last formal comment period, which ended on July 17, 2011, the SDT explained “We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor.” With the addition of an explicit line of sight reference here, the SDT believes it has clarified its original intent and appropriately considered all comments submitted.

Members of the ballot pool should note that for its recirculation ballot, the SDT will be balloting **both** FAC-003-3 and FAC-003-X, but stakeholders should **not** vote as though they are choosing one or the other. The SDT plans to present FAC-003-3 alone to NERC’s Board of Trustees, but it wants to have FAC-003-X ready to submit to the Board if, for some reason, neither FAC-003-2 nor FAC-003-3 are approved by FERC. Members of the ballot body should vote on the merits of each version of FAC-003 individually. **In other words, stakeholders who support adding GOs to the applicability of FAC-003 should vote in the affirmative for both FAC-003-3 and FAC-003-X.**

In PRC-004-2.1, the SDT added a reference to the generator interconnection Facility to the data retention section of the standard (for consistency with the language in R2) and corrected a typo in the Version History.

Several commenters pointed out that the wording in R1 and R2 of PRC-005-1a requires the same explicit reference to a generator interconnection Facility that was added in PRC-004-2.1 R2. The SDT agrees and is developing revisions to PRC-005-1a. These will be posted (separate from the recirculation ballot posting) soon.

Many commenters encouraged the SDT to reexamine the standards and requirements addressed in FERC’s Milford and Cedar Creek orders and NERC staff’s draft compliance directive regarding generator lead lines. The NERC [Standard Processes Manual](#) does not address the issue of how to deal with FERC Orders (that don’t include explicit directives), or draft NERC directives, within the standards process, and until this round of comments, when NERC staff submitted comments, the SDT had no formal mandate that would have made it appropriate to consider the content of the proposed directive.

The SDT reviewed all addressed standards and requirements again and continues to find clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards and not requiring the GO or GOP to register as a TO or TOP. However, to address stakeholder concern, the SDT has expanded its technical justification document (posted under “Supporting Materials”) to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive.

Other minority comments are addressed within specific questions below.

All comments submitted may be reviewed in their original format on the standard's project page:

[http://www.nerc.com/filez/standards/Project2010-07\\_GOTO\\_Project.html](http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html)

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 404-446-2560 or at [herb.schrayshuen@nerc.net](mailto:herb.schrayshuen@nerc.net). In addition, there is a NERC Reliability Standards Appeals Process.<sup>1</sup>

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<sup>1</sup> The appeals process is in the Standard Processes Manual: [http://www.nerc.com/files/Appendix\\_3A\\_Standard\\_Processes\\_Manual\\_20110825.pdf](http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf).

**Index to Questions, Comments, and Responses**

1. Based on stakeholder comment, the SDT clarified the applicability language of FAC-001-1 and removed the Generator Owner from R4. Do you support the proposed redline changes to FAC-001-1? (Please refer to the posted FAC-001-1 technical justification document for more information about the SDT’s rationale for its changes.) ..... 12

2. Do you support the one year compliance timeframe for Generator Owners as proposed in the Implementation Plan for FAC-001-1? ..... 29

3. With respect to FAC-003, many commenters focused on the half-mile qualifier in FAC-003. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: “...that extends greater than one mile beyond the fenced area of the generating station switchyard...” We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.

Taking into consideration that only one of the versions of FAC-003 will actually be implemented, a decision that will be made as Project 2007-07—Vegetation Management moves forward, do you support the proposed redline changes to FAC-003-X and FAC-003-3? ..... 34

4. Do you support compliance timeframe for Generator Owners as included and explained in the Implementation Plans for FAC-003-X? ..... 50

5. In the FAC-003-3 implementation plan, the SDT has attempted to account for a number of different scenarios that could play out with respect to the filing and approvals of FAC-003-2 and FAC-003-3. Do you support this approach? If there are other scenarios that the SDT needs to account for, please suggest them here. .... 57

6. In its technical justification document, the SDT reviews all standards that had been proposed for substantive modification in the Ad Hoc Group’s original support and explains why, with the exception of FAC-003, modifying them would not provide any reliability benefit. Do you support these justifications? If you believe the SDT needs to add more information to its rationale for any of these decisions, please include suggested language here. .... 63

7. The SDT is attempting to modify a set of standards so that radial generator interconnection Facilities are appropriately accounted for in NERC’s Reliability Standards, both to close reliability

- gaps and to prevent the unnecessary registration of GOs and GOPs at TOs and TOPs. Does the set of standards currently posted achieve this goal? ..... 74
- 8. If you answered “yes” to Question 7, are the modifications the SDT has made in this posting the appropriate ones? ..... 87
- 9. If you answered “no” to Question 7, what standards need to be added or removed to achieve the SDT’s goal? Please provide technical justification for your answer. .... 91
- 10. Do you have any other comments that you have not yet addressed? If yes, please explain. .... 99



**The Industry Segments are:**

- 1 — Transmission Owners
- 2 — RTOs, ISOs
- 3 — Load-serving Entities
- 4 — Transmission-dependent Utilities
- 5 — Electric Generators
- 6 — Electricity Brokers, Aggregators, and Marketers
- 7 — Large Electricity End Users
- 8 — Small Electricity End Users
- 9 — Federal, State, Provincial Regulatory or other Government Entities
- 10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment										
				1	2	3	4	5	6	7	8	9	10	
1.	Group	Gerald Beckerle	SERC OC Standards Review Group	X		X								
1.	Scott Brame	NCEMC	SERC 1, 3, 4, 5											
2.	Troy Willis	Georgia Transmission Corp.	SERC 1											
3.	Mike Hirst	Cogentrix	SERC 5											
4.	Bob Dalrymple	TVA	SERC 1, 3, 5, 6											
5.	Matt Carden	Southern Co.	SERC 1, 5											
6.	Shardra Scott	Gulf Power Co.	SERC 3											
7.	Kerry Sibley	Georgia Transmission Corp.	SERC 1											
8.	Andy Burch	EEL	SERC 5											
9.	Shaun Anders	City of Springfield (CWLP)	SERC 1, 3											
10.	Melinda Montgomery	Entergy	SERC 1, 3, 5											
11.	John Troha	SERC Reliability Corp	SERC 10											
2.	Group	Jonathan Hayes	Southwest Power Pool Standards Development Team		X									
<b>Additional Member</b>		<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>										

Group/Individual	Commenter	Organization	Registered Ballot Body Segment																
			1	2	3	4	5	6	7	8	9	10							
1. Jonathan Hayes	Southwest Power Pool	SPP	2																
2. Robert Rhodes	Southwest Power Pool	SPP	2																
3. Don Taylor	Westar	SPP	1, 3, 5, 6																
4. John Allen	City Utilities of Springfield	SPP	1, 4																
5. Sean Simpson	MCPBPU	SPP	1, 3, 5																
6. Louis Guidry	CLECO	SPP	1, 3, 5																
7. Mitch Williams	Western Farmers	SPP	1, 3, 5																
8. Valerie Pinnamonti	AEP	SPP	1, 3, 5																
9. Bud Averill	Grand River Dam Authority	SPP	1, 3, 5																
10. Terri Pyle	OGE	SPP	1, 3, 5																
3.	Group	Guy Zito, Guy Zito	Northeast Power Coordinating Council, Northeast Power Coordinating Council																X
	<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>															
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC, NPCC	10															
2.	Greg Campoli	New York Independent System Operator	NPCC, NPCC	2															
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC, NPCC	1															
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC, NPCC	1															
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC, NPCC	10															
6.	Brian Evans-Mongeon	Utility Services	NPCC, NPCC	8															
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC, NPCC	5															
8.	Kathleen Goodman	ISO - New England	NPCC, NPCC	2															
9.	Chantel Haswell	FPL Group, Inc.	NPCC, NPCC	5															
10.	David Kiguel	Hydro One Networks Inc.	NPCC, NPCC	1															
11.	Michael R. Lombardi	Northeast Utilities	NPCC, NPCC	1															
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC, NPCC	9															
13.	Bruce Metruck	New York Power Authority	NPCC, NPCC	6															
14.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC, NPCC	10															
15.	Robert Pellegrini	The United Illuminating Company	NPCC, NPCC	1															
16.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC, NPCC	1															
17.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC, NPCC	5															
18.	Saurabh Saksena	National Grid	NPCC, NPCC	1															
19.	Michael Schiavone	National Grid	NPCC, NPCC	1															

Group/Individual	Commenter	Organization	Registered Ballot Body Segment											
			1	2	3	4	5	6	7	8	9	10		
20. Wayne Sipperly	New York Power Authority	NPCC, NPCC 5												
21. Tina Teng	Independent Electricity System Operator	NPCC, NPCC 2												
22. Donald Weaver	New Brunswick System Operator	NPCC, NPCC 2												
23. Ben Wu	Orange and Rockland Utilities	NPCC, NPCC 1												
24. Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC, NPCC 3												
4. Group	Emily Pannel	Southwest Power Pool Regional Entity												X
No additional members listed.														
5. Group	Will SMith	MRO NSRF	X	X	X	X	X	X	X	X				X
<b>Additional Member Additional Organization Region Segment Selection</b>														
1. Mahmood Safi	OPPD	MRO	1, 3, 5, 6											
2. Chuck Lawrence	ATC	MRO	1											
3. Jodi Jenson	WAPA	MRO	1, 6											
4. Ken Goldsmith	ALTW	MRO	4											
5. Alice Ireland	XCEL/NSP	MRO	1, 3, 5, 6											
6. Dave Rudolph	BEPC	MRO	1, 3, 5, 6											
7. Eric Ruskamp	LES	MRO	1, 3, 5, 6											
8. Joe DePoorter	MGE	MRO	3, 4, 5, 6											
9. Scott Nickels	RPU	MRO	4											
10. Terry Harbour	MEC	MRO	1, 3, 5, 6											
11. Marie Knox	MISO	MRO	2											
12. Lee Kittelson	OTP	MRO	1, 3, 4, 5											
13. Scott Bos	MPW	MRO	1, 3, 5, 6											
14. Tony Eddleman	NPPD	MRO	1, 3, 5											
15. Mike Brytowski	GRE	MRO	1, 3, 5, 6											
16. Richard Burt	MPC	MRO	1, 3, 5, 6											
6. Group	Charles W. Long	SERC Planning Standards Subcommittee	X											X
<b>Additional Member Additional Organization Region Segment Selection</b>														
1. Pat Huntley	SERC	SERC	10											
2. John Sullivan	Ameren Services Co.	SERC	1											
3. Philip Kleckley	SC Electric & Gas Co.	SERC	1											
4. Bob Jones	Southern Company Services	SERC	1											

Group/Individual	Commenter	Organization	Registered Ballot Body Segment												
			1	2	3	4	5	6	7	8	9	10			
5. Jason Adams	TVA	SERC 1													
7. Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X							
<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>												
1. Timothy Beyrle	City of New Smyrna Beach	FRCC	4												
2. Greg Woessner	Kissimmee Utility Authority	FRCC	3												
3. Jim Howard	Lakeland Electric	FRCC	3												
4. Lynne Mila	City of Clewiston	FRCC	3												
5. Joe Stonecipher	Beaches Energy Services	FRCC	1												
6. Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4												
7. Randy Hahn	Ocala Utility Services	FRCC	3												
8. Group	Mike Garton	Dominion	X		X		X	X							
<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>												
1. Michael Gildea	Dominion Resources Services, Inc.	RFC	5, 6												
2. Connie Lowe	Dominion Resources Services, Inc.	NPCC	5, 6												
3. Michael Crowley	Virginia Electric and Power Company	RFC	1, 3												
9. Group	Annette M. Bannon	PPL NERC Registered Affiliates			X		X	X							
<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>												
1. Brent Ingebrigston	LG&E and KU Services Co.	SERC	3												
2. Don Lock	PPL Brunner Island, LLC	RFC	5												
3.	PPL Martins Creek, LLC	RFC	5												
4.	PPL Holtwood, LLC	RFC	5												
5.	PPL Montour, LLC	RFC	5												
6.	Lower Mount Bethel Energy, LLC	RFC	5												
7. Annete Bannon	PPL Susquehanna, LLC	RFC	5												
8. Leland McMillan	PPL Montana, LLC	WECC	5												
10. Group	Jason Marshall	ACES Power Marketing Standards Collaborators													
<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>												
1. Mohan Sachdeva	Buckeye Power	RFC	3, 5, 6												
2. Erin Woods	East Kentucky Power Cooperative	SERC	1, 3, 5, 6												
3. Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6												

Group/Individual		Commenter	Organization	Registered Ballot Body Segment											
				1	2	3	4	5	6	7	8	9	10		
11.	Group	Steve Rueckert	Western Electricity Coordinating Council												X
No additional members listed.															
12.	Individual	Jack Cashin	Electric Power Supply Association					X	X						
13.	Individual	Natalie McIntire	American Wind Energy Association					X							
14.	Individual	Tom Flynn	Puget Sound Energy, Inc.	X				X	X						
15.	Individual	Silvia Parada Mitchell	Compliance & Responsibility Organization	X		X		X	X						
16.	Individual	Antonio Grayson	Southern Company	X		X		X	X						
17.	Individual	Chris Higgins/Stephen Enyeart/Chuck Mathews/Charles Sheppard	Bonneville Power Administration	X		X		X	X						
18.	Individual	Thad Ness	American Electric Power	X		X		X	X						
19.	Individual	Carla Bayer	BP Wind Energy North America Inc.					X							
20.	Individual	John Bee on behalf of Exelon	Exelon	X				X							
21.	Individual	Dennis Sismaet	Seattle City Light	X		X	X	X	X						
22.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP (Occidental Chemical)					X							
23.	Individual	Michael Falvo	Independent Electricity System Operator		X										
24.	Individual	Greg Rowland	Duke Energy	X		X		X	X						
25.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X											
26.	Individual	Kirit Shah	Ameren	X		X		X	X						
27.	Individual	John Seelke	PSEG	X		X		X	X						
28.	Individual	Andrew Z. Pusztai	American Transmission Company	X											
29.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X						
30.	Individual	Ravi Bantu	RES Americas Development					X							
31.	Individual	Katy Wilson	Sempra Generation					X							

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
32.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
33.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
34.	Individual	Ed Davis	Entergy Services	X		X		X	X				
35.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
36.	Individual	Russell A. Noble	Cowlitz County PUD			X	X	X					
37.	Individual	Anthony Jablonski	ReliabiltyFirst										X
38.	Individual	Donald Jones	Texas Reliability Entity										X
39.	Individual	Amir Hammad	Constellation Power Source Generation					X					
40.	Individual	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

1. **Based on stakeholder comment, the SDT clarified the applicability language of FAC-001-1 and removed the Generator Owner from R4. Do you support the proposed redline changes to FAC-001-1? (Please refer to the posted FAC-001-1 technical justification document for more information about the SDT’s rationale for its changes.)**

#### Summary Consideration:

The SDT thanks all stakeholders for their comments and their 87% approval for the FAC-001-1 changes posted for ballot in November 2011. Based on stakeholder feedback, the SDT has made the following minor changes to FAC-001-1:

-Corrected a typo in Applicability section 4.2.1 to change “within” to “with.”

-Corrected a typo in the VSLs for R3 to ensure that parts 3.1.1 through 3.1.16 were referenced, rather than just 3.1.1 through 3.1.6.

-Changed references to “Transmission System” to “interconnected Transmission systems” to ensure consistency with the language elsewhere in the standard and in FAC-002-1.

Some stakeholders remain concerned about the intent of the SDT’s work on FAC-001-1. The SDT reminded them that the scope is addressed in the SAR. The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT determined that it should first address “low-hanging fruit” and believes these to be sole-use Facilities (see posted examples under “Supporting Materials”) – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP). Through its deliberations, the SDT concluded that an interconnection Facility owned or operated by a GO or GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT.

Concerned commenters were also referred to one of the SDT’s resource documents: [Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document](#).

Some commenters suggested changes to Requirements R1 or R4, which deal exclusively with the Transmission Operator and are outside the scope of the SDT’s work.

One commenter suggested formatting changes. The SDT agrees with the commenter that there are a number of ways to format the standard with this SDT’s revisions. However, the majority of stakeholders support the current format of the standard and no change was made.

One commenter suggested that the phrase “Generator Owner’s existing Facility” be changed to “Generator Owner’s existing Transmission Facility.” The SDT does not agree with labeling a GO’s Facility as “Transmission,” in part because in

some areas (like Texas), GOs, by statute, can't own Transmission. It was also brought to the SDT's attention that in most cases, the Facility in question is referred to as the Interconnection Facility in documents filed by the GO with FERC. Therefore, the SDT intentionally modified language so that a Facility owned by a generation entity did not contain the term "Transmission."

One commenter did not agree with the overall clarifying change to the Applicability section, but the SDT reminded this commenter that this change was made to address previous comments that indicated that there was uncertainty as to whether "another Facility to its existing generation Facility" was meant to address connecting additional generators by the same GO. The SDT intends FAC-001-1 to apply only when the GO of an existing Facility executes an agreement to evaluate the reliability impact of connecting additional generation owned by another GO. No change made with respect to this comment.

A few stakeholders were concerned with the 45-day time frame included in the standard. The SDT pointed out that majority of stakeholders and the SDT support 45 days as a sufficient time frame because in many cases, the GO would simply need to adopt (document and publish) the Facility connection requirements of its TO. No change to that time frame was made.

Organization	Yes or No	Question 1 Comment
Manitoba Hydro	Negative	The intention of the NERC SDT in revising these standards is not clear. While the Technical Justification document states that the SDT intended to focus on a Generator Owner's radial interconnection facilities, the scope of the revised standard (s) is not confined to such facilities. The very broadly defined term "Facility" is used. Moreover, the Technical Justification document's reference to the FERC decision in Cedar Creek as a basis for the revision of additional standards is confusing, since that decision did not specifically address the issue of radial facilities and supported NERC's registration of GOs as TOs.
<p><b>Response:</b> Thank you for your comment. The scope of this SDT is addressed in the <a href="#">SAR</a>. The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT determined that it should first address "low-hanging fruit" and believes these to be sole-use Facilities (see posted examples under "Supporting Materials") – that is, a Facility used to connect one or more generators to a Facility owned or operated by a</p>		



Organization	Yes or No	Question 1 Comment
<p>transmission entity (TO/TOP). Through our deliberations, we came to the conclusion that an interconnection Facility owned or operated by a GO or GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT.</p> <p>The SDT also refers the commenter to the document titled <a href="#">Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document</a>. Specifically, see the last paragraph on page 4 and first two on page 5.</p>		
Southern Company	No	<p>1) R4 is duplicative of R1 - either remove "maintain" from R1 or delete R4 - both instances of "maintain" are not needed.â€¢ 2) The measures, as written, provide no additional indication of the evidence that could be presented to demonstrate compliance with the Reliability Standard Requirements. They provide little guidance on assessing non-compliance with the Requirements. â€¢</p>
<p><b>Response:</b> Thank you for your comment. We agree with your suggestions, but both are outside the scope of this SDT. These items will be submitted to the Issues Database to be addressed in a future revision of FAC-001.</p>		
Southwest Power Pool Standards Development Team	No	<p>Based on the applicability section of FAC-001 we feel that the strike through should have been kept. It limited the requirement to just those generator owners who had agreements in place, which we feel is appropriate.</p>
<p><b>Response:</b> Thank you for your comment. This change was made to address previous comments that indicated to the SDT there was uncertainty as to whether this was meant to address connecting additional generators by the same GO. The SDT intends FAC-001 to apply only when the GO of an existing Facility executes an agreement to evaluate the reliability impact of connecting additional generation owned by another GO. No change made with respect to this comment.</p>		
Texas Reliability Entity	No	<p>In Section 5.1, the reference to Regional Entity should be removed. There are no requirements that apply to the Regional Entity.</p> <p>In Requirements R1 and R4, "Planning Coordinator" should be added after "Regional Entity." In the ERCOT Region it is the Planning Coordinator that maintains planning criteria and connection requirements. There is no NERC</p>

Organization	Yes or No	Question 1 Comment
		<p>requirement or any obligation (as indicated in the technical justification document) on the part of a GO to specifically execute an Agreement to evaluate the reliability impact of interconnecting a third party Facility. Therefore, this requirement’s applicability is contingent on a prerequisite that may not occur, and that is under the control of the GO. This assumption on the part of the SDT unnecessarily complicates the compliance monitoring and enforcement of this standard. For instance, if an “Agreement” is not executed, a GO is not required to comply with the requirement, even though the GO may ultimately interconnect with another entity. The requirement should be modified to include an applicability trigger similar to that of FAC-002-1, so that once a GO “seek[s] to integrate . . .,” i.e., agrees to or is compelled to allow a third-party interconnection, then the requirement becomes applicable. Otherwise, the compliance and monitoring is subject to the SDT’s speculation as indicated in this language included in the technical justification document: “However, the SDT cannot be certain this is the only example and it therefore proposes to add this new requirement to FAC-001-1. In doing so, the SDT acknowledges that the Generator Owner may not, at the time it agrees or is compelled to allow a third party to interconnect, have the necessary expertise to conduct the required interconnect studies to meet this standard. Assuming that a regulatory body would require a Generator Owner to evaluate such an interconnection request, the SDT expects the Generator Owner and the third party to execute some form of an Agreement.”</p>
<p><b>Response:</b> Thank you for your comment. All of these comments are outside the scope of the <a href="#">SAR</a> and the SDT’s work because they refer specifically to the sections and requirements that apply to the TO alone. We encourage you to consider submitting a SAR that addresses your concerns.</p>		
Manitoba Hydro	No	<p>Manitoba Hydro has the following comments:</p> <ol style="list-style-type: none"> <li>1) The intention of the NERC SDT in revising these standards is not clear.</li> </ol>

Organization	Yes or No	Question 1 Comment
		<p>While the Technical Justification document states that the SDT intended to focus on a Generator Owner’s radial interconnection facilities, the scope of the revised standard (s) is not confined to such facilities. The very broadly defined term “Facility” is used. Moreover, the Technical Justification document’s reference to the FERC decision in Cedar Creek as a basis for the revision of additional standards is confusing, since that decision did not specifically address the issue of radial facilities and supported NERC’s registration of GOs as TOs.</p> <p>2) If the drafting team intends to limit the scope of FAC-001-1 to GO owned radial generator interconnection facilities that are not deemed BES transmission and therefore would not require the registration of the GO as a TO, Manitoba Hydro disagrees with the proposed changes to FAC-001-1 as Generator Owners may not have the models or expertise to perform interconnection studies to determine if there is an impact on the Transmission Network. This concern is echoed in the technical justification document provided by NERC: ‘the SDT acknowledges that the Generator Owner may not, at the time it agrees or is compelled to allow a third part to interconnect, have the necessary expertise to conduct the required interconnect studies to meet this standard... the Generator Owner will have to acquire such expertise. How the Generator Owner chooses to do so is not for the SDT to determine.’ Although it may not be for the SDT to determine how a GO obtains technical expertise, ensuring that such expertise is acquired before a GO conducts the required interconnection studies should be a concern to NERC as this directly affects the reliability of the BES. As a result, all interconnection requests should be implemented by the TO providing the GO with connection to the BES regardless if the interconnection point is within a Generation Owner facility or End-User facility as the TO is in the best position to set unbiased connection requirements to ensure the reliability of the BES is maintained. If the scope of FAC-001-1 also applies to GO owned BES transmission facilities, Manitoba</p>

Organization	Yes or No	Question 1 Comment
		<p>Hydro strongly believes that the Compliance Registry should apply and the GOs should be required to register as a TO and abide by all applicable standards to that functional type. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. Reliability gaps would be better addressed if select GOs and GOPs registered as TOs and TOPs to ensure all reliability standards, including the protection standards, are met so the reliability of the BES is maintained. At this time, this would not lead to a large number of extra registrations since, as stated in the technical justification document, ‘interconnection requests for Generator Owner Facilities are still relatively rare.</p> <p>3) If the redline changes are implemented, GOs are removed from R4, thereby removing the obligation for GOs to maintain their connection requirements. If GOs are included in FAC-001, they should be held accountable to the same level as TOs and should be required to maintain their connection requirements. Requiring a GO to maintain connection requirements would be especially beneficial to the GO themselves. In the majority of instances, any GO that is an Applicable Entity for FAC-001 would initially be inexperienced in performing interconnection studies and would benefit from regular and frequent review of their connection requirements as experience and expertise are gained.</p> <p>4) The revision to FAC-001-1 R2 may be problematic, depending on what was intended. Under the revised requirement, the obligation to comply is dependent on the execution of an agreement to evaluate reliability impacts under FAC-002-1. However, FAC-002-1 does not clearly require the execution of an agreement by the Generator Owner. FAC-002-1 only requires the Generator Owner to “coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority”. Accordingly if a Generator Owner coordinates without executing an agreement to perform an assessment, compliance with FAC-001 R1 will not</p>

Organization	Yes or No	Question 1 Comment
		<p>be required.</p> <p>5) Manitoba Hydro would also like to point out that if the redline changes are implemented, it will greatly increase the complexity of coordination required under FAC-002-1 for Transmission Planners/Planning Authorities.</p>
<p><b>Response:</b> Thank you for your comment. The scope of this SDT is addressed in the <a href="#">SAR</a>. The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP).</p> <p>The intent of the modifications to this standard is to address the requirements of the GO prior to the interconnection of the third party to their Facilities. The reliability gap the SDT intends to close is the need for the GO to develop Facility connection requirements prior to interconnection. The SDT does agree that upon interconnection of a third party, other standards or registrations may apply as appropriate.</p> <p>The SDT also refers the commenter to the document titled <a href="#">Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document</a>, which is posted on the project page. Specifically, see the last paragraph on page 4 and first two on page 5.</p>		
Tennessee Valley Authority	No	<p>Suggest that the overall structure of the standard be revised such that R1 - R3 are applicable to the Transmission Owner (consistent with existing FAC-001-0) and R4 (the new requirement) is applicable to the “applicable Generator Owner”. See further comments below. Support the proposed revisions to R1 and R4, but suggest R4 be returned to R3 (consistent with existing FAC-001-0).R3 in the balloted standard should be returned to R2 (consistent with existing FAC-001-0) and only be applicable to the Transmission Owner. R3.1 (or R2.1 if moved back) should be “fixed”, but it may be beyond this SDT’s charge. The use of “above” in the FAC-001-0 standard, or the proposed reference to “Requirements R1 or R2” in the proposed standard do not make sense in combination with the colon used at the end of the requirement. Suggest that R3.1 (or 2.1 if moved back) be revised as written below and all sub-requirements of R3.1 be elevated (R3.1.1 becomes R3.2, R3.1.2 becomes R3.3, etc.).”R3.1 Performance</p>

Organization	Yes or No	Question 1 Comment
		<p>requirements and/or planning criteria used to assess system impacts.” R2 in the balloted standard should become R4 and modified to incorporate the connection requirements contained in R3 that can more reasonably be expected of an “applicable Generator Owner”. For instance, an “applicable Generator Owner” might simply have a connection requirement for a third party that addresses coordination of system impact studies with the appropriate Transmission Owner(s), in lieu of R3.1, R3.1.1, and R3.1.2. Suggest that R2 (or R4 if moved below existing FAC-001-0 requirements) be revised as written below.”R2 Each applicable Generator Owner that has agreed to allow a third party Facility owner (Generation Facility, Transmission Facility, or End-user Facility) to connect to the Transmission system through use of pre-existing applicable Generator Owner Facilities shall communicate it’s Facility connection requirements to the third party. The applicable Generator Owner Facility connection requirements shall address the following items: R2.1 Coordination of system impact studies with the Transmission Owner. R2.2 Voltage level and MW and MVAR capacity or demand at point of connection. R2.3 Breaker duty and surge protection. R2.4 System protection and coordination R2.5 Metering....” Etc.</p>
<p><b>Response:</b> Thank you for your comment. We gave the comment due consideration and agree that there are a number of ways to format the standard with this SDT’s revisions. However, the majority of stakeholders support the current format of the standard. No change made.</p>		
<p>Northeast Power Coordinating Council, Northeast Power Coordinating Council</p>	<p>No</p>	<p>The intent of the draft language in FAC-001-1 is to provide guidance for addressing the alleged reliability gap that exists between GO/GOPs that own/ operate transmission facilities but are not registered as TO/TOPs. The impact of the revised language will depend on the characterization of the generator lead after the “third party “ connects to the existing generator lead. IF the generator lead is owned by the TO utility after the third party connection : The proposed DRAFT FAC-001 language suggests that within 45 days of a 3rd party having an executed Agreement to evaluate the reliability</p>

Organization	Yes or No	Question 1 Comment
		<p>impact of interconnecting, the existing generator needs to document and publish facility connection requirements. The proposed language suggests that a third party can commandeer existing generators leads and interconnect. A reclassification would be required because “third party” power would flow through the downstream portions of the existing leads. This introduces significant challenges for defining ownership / transfer of installed assets as well as real property, easements, operational jurisdiction, O&amp;M cost responsibility, etc. The FERC approved pro-forma Attachment X Interconnection Agreement clearly states that the project Developer must meet all Applicable Reliability Standards which means that all requirements and guidelines of the Applicable Reliability Councils, and the Transmission District to which the Developer’s Large Generating Facility is directly interconnected. As an example, to accommodate this NERC proposal, the FERC approved NYISO pro-forma tariff would need to be revised to allow this “third party” use. The pro-forma interconnection tariff also states that the Developer must provide updated project information prior to the Facilities Study. The Facilities Study might not be made until several years after the Interconnection Request /Feasibility Study is made (“executed Agreement to evaluate the reliability impact of interconnecting” in this proposed draft is akin to the Interconnection Request/Feasibility Study). Placing the requirement to have the existing Generator Owner publish reliability requirements for a potential “third party user”, without the generator having any knowledge of the potential reliability outcomes or asset transfer / ownership issues is not a reasonable expectation. The interconnection of a third party to an existing generator lead would force existing generators to revise their Interconnection Agreements with FERC. The “third party”, would at a minimum, need to comply with the existing Generators reliability obligations as specified in the Interconnection Agreement. IF the third party connects to the GO owned generator lead, the GO will be considered a TO:A TO would not be involved, other than review</p>

Organization	Yes or No	Question 1 Comment
		<p>of the SRIS and Facilities reports. The difficult thing for an existing GO would be to prepare, within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility, a document listing the requirements. To allow for the above possibilities, the language for applicability of FAC-001 to GO’s or GOP’s, should be :”Each applicable Generator Owner shall, at least 60 days prior to execution of a Facilities / Class Year Study Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the Transmission System, document and publish its Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, sub regional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements.”</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees with many of the comments (as indicated in the accompanying resource document titled <a href="#">Technical Justification: FAC-001-1</a>), especially those concerning the complexities of this process. The majority of stakeholders and the SDT support 45 days as a sufficient time frame because in many cases, the GO would simply need to adopt (document and publish) the facility connection requirements of its TO. No change made.</p>		
<p>Consolidated Edison Co. of NY, Inc.</p>	<p>No</p>	<p>The language for FAC-001 Requirement R2 should be:”This requirement shall apply to each applicable Generator Owner. Generator Owner filings must be made at least 60 days in advance of execution of the final interconnection study agreement in the Planning Coordinator’s or Transmission Planner’s study process.Each applicable Generation Owner must publish its Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, sub regional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements.The evaluation of the reliability impact(s) of interconnecting a third party Facility to the Generator Owner’s existing Facility utilized for interconnection to the Transmission System must be</p>



Organization	Yes or No	Question 1 Comment
		documented.”
<p><b>Response:</b> Thank you for your comment. The SDT agrees with many of the comments (as indicated in the accompanying resource document titled <a href="#">Technical Justification: FAC-001-1</a>), especially those concerning the complexities of this process. The majority of stakeholders and the SDT support 45 days as a sufficient time frame because in many cases, the GO would simply need to adopt (document and publish) the facility connection requirements of its TO. No change made.</p>		
<p>Ingleside Cogeneration LP (Occidental Chemical)</p>	<p>No</p>	<p>Unfortunately, the vital point of this requirement revolves around whether or not a Generator Owner is compelled externally to allow access to their interconnection facilities. If the GO is driving the connection for financial or other business reasons, there is no reason they should not be responsible for developing AND maintaining a facility connection requirements document. Otherwise, when the local transmission system requirements change for any reason, there will be no entity responsible to ensure that the third party will conform as well. Conversely, if the GO should be compelled to allow access to a third party, it is the responsibility of the “compeller” to handle all the related reliability studies and documents. This may include the development of a CFR which separates reliability tasks between the GO and other entities - especially if a TSP registration is required. This ensures that the Regional Entity, PUC, RTO, or other regulator must budget dollars and resources directly related to their action - not cause them to be directed to a GO.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees with many of the comments (as indicated in the accompanying resource document titled <a href="#">Technical Justification: FAC-001-1</a>), especially those concerning the complexities of this process. However, the issues you raise are beyond the scope of the SDT and its SAR. No change made.</p>		
<p>PSEG</p>	<p>No</p>	<p>We revised this partial sentence to the following: “Each applicable Generator Owner shall, within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Transmission Facility that is used for connection</p>

Organization	Yes or No	Question 1 Comment
		<p>to the interconnected Transmission systems (under FAC-002-1), ..."- The phrase "Generator Owner's existing Facility that is used to interconnect to the Transmission System" was changed to "Generator Owner's existing Transmission Facility that is used for connection to the interconnected Transmission systems." - "Transmission" was added before Facility to exclude connections elsewhere; "Transmission System" was changed to "Transmission systems" because while "Transmission" and "System" are defined in the NERC Glossary, "System" means "A combination of generation, transmission, and distribution components." "Transmission systems" do not have generation or distribution components, so a lower case "system" is warranted. - In addition, the suggested phrase "interconnected Transmission systems" (plural "systems") uses identical language from FAC-002-1, except that we capitalized "Transmission.</p>
<p><b>Response:</b> Thank you for your comment. The SDT has addressed the proposed change to applicability according to your comments. The applicability section now reads: "Generator Owner with an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems.</p> <p>The SDT has been informed that in some areas (like Texas), GOs, by statute, can't own Transmission. It was also brought to the SDT's attention that in most cases, the Facility in question is referred to as the Interconnection Facility in documents filed by the GO with FERC. Therefore, the SDT intentionally modified language so that a Facility owned by a generation entity did not contain the term "Transmission."</p>		
Seattle City Light	Affirmative	Key points are that (1) an executed agreement is required before evaluations of impacts are necessary and (2) this only applies when a third party is connecting to the generating interconnection line.
<p><b>Response:</b> Thank you for your comment.</p>		
Electric Power Supply Association	Yes	All TO requirements for FAC-001-1 would apply if and when GO executes an Agreement to evaluate the reliability impact of interconnecting a third

Organization	Yes or No	Question 1 Comment
		<p>party Facility to its existing generation interconnection Facility. The execution of the agreement is necessary to comply with FAC-002-1 and start the compliance clock with the applicable regulatory authority. Thus as the Project 2010-07 Standard Drafting Team (SDT) in its technical justification has stated, “If, and only if, the existing owner of a generator interconnection Facility has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to its existing generation Facility” then FAC-001-1 should apply. EPSA concurs with SDT’s conclusion. The SDT has examined the issue regarding if future requests for transmission service on the interconnection Facility and in doing so acknowledged that when that Facility adopted open access and was providing transmission service it would necessitate re-evaluation of the need for the Facility to be maintained in accordance with FAC-001-1, Requirements 2 and 4. This service would indeed prompt the necessary agreement the SDT contemplates in its technical justification of FAC-001-1. EPSA believes this serves as the necessary trigger for evaluation of Requirements 2 and 4 under FAC-001-1 for GOs.</p>
<p><b>Response:</b> Thank you for your comment.</p>		
<p>American Wind Energy Association</p>	<p>Yes</p>	<p>AWEA appreciates that this standard specifies that it has limited applicability. For instance, only those generators that have an executed agreement with a third party wishing to interconnect must document and publish Facility connection requirements. We believe the proposed 45-day time window is a minimum for GO/GOP owners of generator lead lines to provide this documentation following execution of such an agreement. Anything less than 45 days could result in a burdensome and hard to meet deadline for GO/GOP staff. However, AWEA believes that extending this time window for publishing Facility connection requirements to 90 days after an executed agreement would be beneficial. We believe this will allow the GO/GOP owners of generator leads more time to coordinate with their</p>

Organization	Yes or No	Question 1 Comment
		interconnecting Transmission Providers and will result in more reliable and coordinated connection requirements for the generator lead.
<p><b>Response:</b> Thank you for your comment. The majority of stakeholders and the SDT support 45 days as a sufficient time frame because in many cases, the GO would simply need to adopt (document and publish) the facility connection requirements of its TO. No change made.</p>		
SERC OC Standards Review Group	Yes	Please verify within the applicability section (4.2.1) you intended to use the word “within” rather than some other wording.
<p><b>Response:</b> Thank you for your comment. The SDT intended it to read “Generator Owner <b>with</b> an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the Transmission System.” This change has been made.</p>		
RES Americas Development	Yes	RES Americas and AWEA appreciate that this standard specifies that it has limited applicability. For instance, only those generators that have an executed agreement with a third party wishing to interconnect must document and publish Facility connection requirements. We believe the proposed 45-day time window is a minimum for GO/GOP owners of generator lead lines to provide this documentation following execution of such an agreement. Anything less than 45 days could result in a burdensome and hard to meet deadline for GO/GOP staff. However, we believes that extending this time window for publishing Facility connection requirements to 90 days after an executed agreement would be beneficial. We believe this will allow the GO/GOP owners of generator leads more time to coordinate with their interconnecting Transmission Providers and will result in more reliable and coordinated connection requirements for the generator lead.
<p><b>Response:</b> Thank you for your comment. The majority of stakeholders and the SDT support 45 days as a sufficient time frame because in many cases, the GO would simply need to adopt (document and publish) the facility connection requirements of its TO</p>		

Organization	Yes or No	Question 1 Comment
No change made.		
ACES Power Marketing Standards Collaborators	Yes	We largely agree with the changes the drafting team made but believe some additional changes are necessary. In section 4.2.1 of the Applicability Section, “within” should be “with”. Because NERC’s Glossary of Terms establishes that an Agreement can be verbal and not enforceable by law, section 4.2.1 should be further modified to clarify that it is a legally enforceable and fully executed Agreement. The language in R3 in parenthesis after Generation Owner should be modified to “once required by Requirement R2”. This makes it clearer that R3 does not apply until the GO has an executed Agreement to evaluate a request by a third part to interconnect.
<p><b>Response:</b> Thank you for your comment. We agree that “within” should be “with”. The SDT chose not to adopt the second recommendation as the requirement already contains the term “executed.” The SDT also chose not to adopt the third recommendation as the requirement already contains the parenthetical (in accordance with Requirement R2) which we feel is synonymous with the comment.</p>		
Southwest Power Pool Regional Entity	Yes	
MRO NSRF	Yes	
SERC Planning Standards Subcommittee	Yes	
Florida Municipal Power Agency	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	

Organization	Yes or No	Question 1 Comment
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Exelon	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
Ameren	Yes	
American Transmission Company	Yes	
South Carolina Electric and Gas	Yes	
Sempra Generation	Yes	
Xcel Energy	Yes	
Cowlitz County PUD	Yes	
Constellation Power Source Generation	Yes	
ReliabilityFirst		
Entergy Services		

Organization	Yes or No	Question 1 Comment
Western Electricity Coordinating Council		
Puget Sound Energy, Inc.		
Compliance & Responsibility Organization		
Bonneville Power Administration		

**2. Do you support the one year compliance timeframe for Generator Owners as proposed in the Implementation Plan for FAC-001-1?**

**Summary Consideration:**

The vast majority of commenters supported the one year compliance time frame in the Implementation Plan. A few commenters were concerned with this time frame and associated enforcement, in part based on similar issues addressed in recent CANs. The SDT did its best to clarify its intent as follows:

The SDT’s intent is that the mandatory date (the date upon which the GO must be compliant with applicable requirements and measures) be the first calendar day of the first calendar quarter one year after FAC-001-1’s approval. The SDT believes one year is sufficient time for the GO to become compliant where it has one or more in-place (which we interpret as synonymous with legacy or grandfathered) executed Agreement(s). If an Agreement is executed after the mandatory date, then the GO has 45 days to “document and publish its Facility connection requirements” (R2) and those requirements shall address items under R3.

No changes were made to the Implementation Plan.

Organization	Yes or No	Question 2 Comment
Ingleside Cogeneration LP (Occidental Chemical)	No	Based upon similar issues addressed in Compliance Application Notices (CANs), the drafting team needs to specify how the requirements apply to an in-place “executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the Transmission System.” In the view of Ingleside Cogeneration LP, if the Agreement takes effect even one day before FAC-001-1 does, requirements R2 and R3 do not apply. Without this clarification, it is possible that NERC’s Compliance team will apply the requirements retroactively - with minimum industry input.
<p><b>Response:</b> Thank you for your comment. The SDT’s intent is that the mandatory date (the date upon which the GO must be compliant with applicable requirements and measures) be the first calendar day of the first calendar quarter <u>one year after its approval</u>. The SDT believes one year is sufficient time for the GO to become compliant where it has one or more in-place (which we interpret as synonymous with legacy or grandfathered) executed Agreement(s). If an Agreement is executed after the mandatory date, then the GO has 45 days to “document and publish its Facility connection requirements” (R2) and those requirements shall</p>		



Organization	Yes or No	Question 2 Comment
address items under R3.		
Southwest Power Pool Regional Entity	No	No action is required unless a GO has an executed third-party agreement. If a GO has an agreement, the standard already includes a 45-day timeframe for the GO to document and publish its facility connection requirements.
<p><b>Response:</b> Thank you for your comment. The SDT’s intent is that the mandatory date (the date upon which the GO must be compliant with applicable requirements and measures) be the first calendar day of the first calendar quarter <u>one year after its approval</u>. The SDT believes one year is sufficient time for the GO to become compliant where it has one or more in-place (which we interpret as synonymous with legacy or grandfathered) executed Agreement(s). If an Agreement is executed after the mandatory date, then the GO has 45 days to “document and publish its Facility connection requirements” (R2) and those requirements shall address items under R3.</p>		
Southern Company	No	See our response to Question 9.
<p><b>Response:</b> See the SDT’s response to Question 9.</p>		
Manitoba Hydro	No	See question 1 comments.
<p><b>Response:</b> See SDT’s response to Question 1.</p>		
Cowlitz County PUD	Yes	Cowlitz PUD (District) registered as a Transmission Owner shortly before FAC-001-0 became effective and was forced to file a Mitigation Plan in order to facilitate compliance. The District successfully completed compliance implementation and documentation in eight months. The proposed one year compliance timeframe is sufficient.
<p><b>Response:</b> Thank you for your comment and support.</p>		
Seattle City Light	Yes	The proposed changes for FAC-001-1 state a 45 day period to complete the evaluation. Not sure what the question is referring to regarding “ 1 year “?

Organization	Yes or No	Question 2 Comment
<p><b>Response:</b> Thank you for your comment. The SDT’s intent is that the mandatory date (the date upon which the GO must be compliant with applicable requirements and measures) be the first calendar day of the first calendar quarter <u>one year after its approval</u>. The SDT believes one year is sufficient time for the GO to become compliant where it has one or more in-place (which we interpret as synonymous with legacy or grandfathered) executed Agreement(s). If an Agreement is executed after the mandatory date, then the GO has 45 days to “document and publish its Facility connection requirements” (R2) and those requirements shall address items under R3.</p>		
<p>American Wind Energy Association / RES Americas Development</p>	<p>Yes</p>	<p>Yes, since there is no exigent reason why this standard needs to be put in place at once, we support the one-year compliance timeframe. We believe that it will allow generators a reasonable time to comply with the requirement.</p>
<p><b>Response:</b> Thank you for your comment and support.</p>		
<p>SERC OC Standards Review Group</p>	<p>Yes</p>	
<p>Southwest Power Pool Standards Development Team</p>	<p>Yes</p>	
<p>Northeast Power Coordinating Council, Northeast Power Coordinating Council</p>	<p>Yes</p>	
<p>MRO NSRF</p>	<p>Yes</p>	
<p>SERC Planning Standards Subcommittee</p>	<p>Yes</p>	
<p>Florida Municipal Power Agency</p>	<p>Yes</p>	

Organization	Yes or No	Question 2 Comment
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Electric Power Supply Association	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Exelon	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
Ameren	Yes	
PSEG	Yes	
American Transmission Company	Yes	

Organization	Yes or No	Question 2 Comment
South Carolina Electric and Gas	Yes	
Sempra Generation	Yes	
Xcel Energy	Yes	
Constellation Power Source Generation	Yes	
Western Electricity Coordinating Council		
Puget Sound Energy, Inc.		
Compliance & Responsibility Organization		
Bonneville Power Administration		
Consolidated Edison Co. of NY, Inc.		
Entergy Services		
ReliabilityFirst		
Texas Reliability Entity		

3. With respect to FAC-003, many commenters focused on the half-mile qualifier in FAC-003. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: “...that extends greater than one mile beyond the fenced area of the generating station switchyard...” We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.

Taking into consideration that only one of the versions of FAC-003 will actually be implemented, a decision that will be made as Project 2007-07—Vegetation Management moves forward, do you support the proposed redline changes to FAC-003-X and FAC-003-3?

#### Summary Consideration:

The SDT thanks all stakeholders for their comments and their over 85% approval for the FAC-003-X and FAC-003-3 changes posted for ballot in November 2011. Based on stakeholder feedback, the SDT has made the following changes:

- Added a clarifying reference to line of sight in the GO exemption in section 4.3.1.
- Corrected a typo in 4.3.1.2 of FAC-003-3.
- Changed “RE” to “Regional Entity” in 4.3.1 of FAC-003-X.

As it discusses in the document titled “[Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface](#),” the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.

To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: “Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”

With this reference, the SDT simply seeks to clarify the exception language based on the intent that has been agreed upon by the stakeholder body. In its [Consideration of Comments report](#) from the last formal comment period, which ended on July 17, 2011, the SDT explained “We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor.” With the addition of an explicit line of sight reference here, the SDT believes it has clarified its original intent and appropriately considered all comments submitted.

Some stakeholders suggested changes that should have been submitted when Project 2007-07 was revising FAC-003-2, because these suggestions dealt with the standard as a whole rather than the changes made by this SDT to ensure that GOs are included in the standard’s applicability.

One commenter remains concerned about the scope of the SDT. The SDT reminded this commenter that its scope is addressed in the [SAR](#) and that its intent is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT also refers the commenter to the document titled [Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document](#). Specifically, see the last paragraph on page 4 and first two on page 5.

Organization	Yes or No	Question 3 Comment
Ameren Services	Negative	<p>(a) There is no technical basis for the one mile length exemption. In fact, one could argue that a very short line, 300 feet in length, that experienced a fault from a tree at "the end of the circuit", i.e near the switchyard fence, would have much more of an impact on the BES because the fault would be limited by much less impedance.</p> <p>(b) It is also unclear in this version if a GO that owned one line that was 1.2 miles in length would have to comply for the entire length of said line, or just 0.2 miles of said line. If the GO is responsible for 1.2 miles, then that argues that the first mile is important and consequently there is no basis for ignoring the first mile on other lines. If the GO is only responsible for 0.2 miles, what is the technical basis to ignore a mile? And would it be the first mile from the switchyard that is ignored, or is the middle mile, or the last mile where it connects to the TO? Or could the GO decide? Or could the GO pick sections of the line that amount to a mile that they can ignore? This seems like something that should be addressed for compliance.</p>

Organization	Yes or No	Question 3 Comment
		<p>(c) The 2 year compliance time line is far too long. There is significant industry evidence that was developed in the drafting of Version 2 that supports a one year compliance time-line for new lines. This is evidenced in Version 2. Thus there is no basis for the 2 years</p>
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled "<a href="#">Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface</a>," the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: "Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are..."</p> <p>With respect to your second comment, the SDT intended for the length qualifier to be just that; if the overhead portion of a Facility exceeds the distance, <u>the entire Facility</u> is subject to the requirements of the standard.</p> <p>The SDT chose the time in the implementation plan based upon reasons it documented in the <a href="#">accompanying implementation plan</a> and also based upon comments of stakeholders.</p>		
<p>Wisconsin Public Service Corp Electric Cooperative</p>	<p>Negative</p>	<p>R1.2 refers to an encroachment due to a fall in. This is confusing because according to the dictionary "Webster's II" encroachment reads: "to intrude gradually", and a 'fall in' is not usually gradual.</p>
<p><b>Response:</b> Thank you for your comment. This is outside the scope of the <a href="#">SAR</a>. The SDT reviewed comments submitted as part of the <a href="#">Project 2007-07</a> effort and did not find this comment had been submitted.</p>		
<p>Wisconsin Public Service Corp.</p>	<p>Negative</p>	<p>The concern with the proposed wording is that many generating station may not have a "generating station switchyard" as implied by the proposed wording. Often the generator leads (e.g. 20 kV) will exit the generator and connect to transformers located in transformer bays directly adjacent to the plant. From the transformers the now greater than 200 kV lines will be routed to the point of interconnect or a</p>

Organization	Yes or No	Question 3 Comment
		<p>generating unit switchyard, possibly miles or yards away. By no one’s definitions would the transformer bays adjacent to the plant be considered a switchyard. The plant fence may be yards or hundreds of yards from the bays and on a multiple unit site, there may be a site fence or boundary, which could be comprise of fences, security patrols, or other barriers yards or miles from the transformer but enveloping the switchyard. The valid assumption made by the drafting team is that transmission lines within an area tightly controlled by the generator operator poses very little risk to the BES as a result of vegetation contact. This assumption is based on the valid observation that these areas are routinely occupied and observed by station personnel and as a result unexpected and unacceptable vegetation growth is highly unlikely because it is controlled by routine maintenance. It also correctly assumes that some distance past the controlled area is acceptable since this area would also be under near continuous observation. The problem comes in defining both a tightly controlled area and a line of site. We suggest the following: Controlled Area: A perimeter around a power plant, power plants, or switchyard which is prevents intrusion by the use of physical barriers, observation, or electronic monitoring and is routinely occupied such that unexpected and unacceptable vegetation growth would be observed and correct as a matter of routine maintenance. Line of Sight: A two kilometer distance from the controlled area perimeter.</p>
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled <a href="#">“Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface,”</a> the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: “Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”</p>		
Florida Reliability	Negative	There is no technical justification for excluding 1 mile beyond the fence in the



Organization	Yes or No	Question 3 Comment
Coordinating Council		applicability of generators.
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled "<a href="#">Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface</a>," the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: "Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are..."</p>		
Southern Company	No	<p>â€¢All of these comments pertain to FAC-003-3:</p> <ol style="list-style-type: none"> <li>1) We suggest referring to the Implementation Plan in the Effective Date sub-section of Section A of the standard rather than repeating the content of the Implementation Plan in the standard. There exists unnecessary duplication with including the information in both places.</li> <li>2) We suggest simplifying the purpose statement to more succinctly say the intent, for example: "To maintain a reliable transmission system by managing vegetation located on transmission rights of way to minimize vegetation encroachments and thereby minimize the risk of vegetation related outages". If this change is not acceptable, at least change the phrase "preventing the risk" to "minimizing the risk".</li> <li>3) We feel that the Enforcement paragraphs between 4.3.1.3 and 5.0 seem to be out of place. Those paragraphs don't belong in this location - consider moving them to Section C. Compliance. The fourth paragraph belongs in the background section.</li> <li>4) We suggest moving the background section to Section F. "Associated Documents". It gets in the way of getting to the requirements of the standard.</li> <li>5) We suggest moving Table 2 of the "Guideline and Technical Basis" document into R1, since it seems to be the only part of the document that is enforceable. Further</li> </ol>

Organization	Yes or No	Question 3 Comment
		<p>we suggest that the Guideline and Technical Basis document be removed from the standard. The inclusion of this document in the standard makes the standard unwieldy.</p> <p>6) We suggest reordering the words in R1 to more clearly state the requirement. Please consider this rephrasing: "For lines which are either an element of an IROL or an element of a Major WECC Transfer Path, each applicable TO and applicable GO shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) when operating within their Rating during all Rated Electrical Operating Conditions of the types shown below:..." (remainder is unchanged).</p> <p>7) We suggest reordering the words of R2 to more clearly state the requirement. Please consider the this rephrasing: "For lines which are neither an element of an IROL nor an element of a Major WECC Transfer Path, each applicable TO and applicable GO shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) when operating within its Rating and during all Rated Electrical Operating Conditions of the types listed below:..." (remainder is unchanged).</p> <p>8) On Page 11 of the posted clean draft standard, is the reference to the previous footnote 2 correct? We recommend eliminating footnotes where possible to minimize redirections.</p> <p>9) The Rationale text-box on page 13 of the clean version of FAC-003-3 overlaps some of the text of footnote #6.   â€€,â€€,â€€,</p>
<p><b>Response:</b> Thank you for your comment.</p> <p>With respect to your suggestion regarding the implementation plan, the SDT simply followed the NERC-mandated document guidelines. Making the change you suggest would deviate from that process and thus the SDT has not made it.</p> <p>With respect to comments 2-8, any standard changes that go beyond making a standard applicable to a GO or GOP are beyond the scope of this SDT. Any redline changes the SDT has made within standards were made to clarify or qualify the GO or GOP applicability. These comments would have been more appropriate to make during the comment period for Project 2007-07 Vegetation Management, the project that revised the version of FAC-003 from which this SDT is working.</p>		

Organization	Yes or No	Question 3 Comment
We have modified the rationale box on page 13 so that it does not overlap with the text of footnote 6.		
Dominion	No	<p>Dominion suggests in FAC-003-X; 4.3.1. Regional Entity be changed to RE as listed in 4.2.1 for consistency. Also Regional Entity is used throughout the rest of the document, suggest using RE for consistency overall. Dominion suggests in FAC-003-3; 4.3.1. adding station to the following “ Overhead transmission lines that extend greater than one mile or 1.609 kilometers beyond the fenced area of the generation station switchyard and are” to show consistency as it is written in FAC-003-X 4.3.1. Further, Dominion is concerned that the technical justification characterized the exclusion (i.e., one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard) as “approximate line of sign [sic] from a fixed point” and notes that this line of sight may be limited by local terrain. Where line of sight of the radial corridor is limited on a clear day due to terrain, the one mile exemption must be limited in distance to no more than the line of sight on a clear day beyond the fenced area.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees with your comment about the Regional Entity, but will instead use Regional Entity throughout.</p> <p>Thank you for your comment. As it discusses in the document titled <a href="#">“Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface,”</a> the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: “Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”</p>		
Exelon	No	FAC-003 - Exelon supports the one mile length qualifier, but feels that additional clarification is needed to determine the points of demarcation. There are too many differing physical configurations to use a “fence line” as a determination of

Organization	Yes or No	Question 3 Comment
		<p>applicability. Suggest that the tie line length be defined as “from the Generator Step up Transformer GSU to the point of interconnection between the GO and TO owned equipment.” Also suggest that the standard define what constitutes a generation station switchyard.</p>
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled <a href="#">“Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface,”</a> the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: “Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”</p>		
<p>Ingleside Cogeneration LP (Occidental Chemical)</p>	<p>No</p>	<p>Ingleside Cogeneration LP is very concerned that the attempt to develop “bright-line” criteria to assign applicability to either version of FAC-003 is misplaced. As seen with NERC’s recent proposed directive related to Generator-Transmission interconnections, those thresholds can be arbitrarily reduced based upon regulators aversion to risk - not scientific evidence. (As it stands today, NERC has proposed any interconnection facility operating at 100 kV or higher and greater than 3 spans in length be applicable - which is even stricter than the TO thresholds in FAC-003.) This would suggest that a reliability assessment consistent with the TPL standards must be the determining factor. If the Planning Coordinator or Transmission Planner can show that the Generator-Transmission interconnection could contribute to a violation of an SOL or IROL, then a vegetation management program may be in order. Furthermore, there needs to be some level of common sense applied if a GO-TO interconnection is located in an area where vegetation clearance is never an issue. A one-size-fits-all requirement based upon vegetation growth in the sub-tropics, should not automatically apply in the desert. In our view, every dollar spent to control vegetation in an arid climate is one less dollar available to purchase</p>

Organization	Yes or No	Question 3 Comment
		advanced telemetry, AGC systems, and other items which have a far greater impact on reliability.
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled <a href="#">“Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface,”</a> the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: “Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”</p> <p>The SDT also took into consideration the stakeholder comments submitted and believes this exemption adequately addresses the reliability impact for a majority of the Facilities, while balancing the efforts necessary to support the standard from all entities.</p>		
Manitoba Hydro	No	Manitoba Hydro does not support the changes being proposed in this project. If a Generator Owner is required to register as a TO, all the Requirements applicable to a TO should apply. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions.
<p><b>Response:</b> Thank you for your comment. The scope of this SDT is addressed in the <a href="#">SAR</a>. The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT also refers the commenter to the document titled <a href="#">Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document</a>. Specifically, see the last paragraph on page 4 and first two on page 5.</p>		
Northeast Power Coordinating Council, Northeast Power Coordinating Council	No	Suggest in FAC-003-X; 4.3.1. that Regional Entity be changed to RE as listed in 4.2.1 for consistency. Also Regional Entity is used throughout the rest of the document, suggest using RE for consistency. In FAC-003-3; 4.3.1. add station to the following: “Overhead transmission lines that extend greater than one mile or 1.609 kilometers beyond the fenced area of the generation station switchyard and are” to show consistency as it is written in FAC-003-X 4.3.1. The technical justification characterized the exclusion (i.e., one mile or 1.609 kilometers beyond the fenced

Organization	Yes or No	Question 3 Comment
		<p>area of the generating station switchyard) as “approximate line of sight [sic] from a fixed point” and noted that this line of sight may be limited by local terrain. Where line of sight of the radial corridor is limited on a clear day due to terrain, the one mile exemption must be limited in distance to no more than the line of sight on a clear day beyond the fenced area.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees with your comment about the Regional Entity, but will instead use Regional Entity throughout.</p> <p>Thank you for your comment. As it discusses in the document titled <a href="#">“Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface,”</a> the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: “Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”</p>		
MRO NSRF	No	<p>The NSRF agrees with the drafting committees desire to eliminate arbitrary and capricious behavior of auditors and industry staff by precisely defining the point at which measurement starts for the length of transmission line. The concern the NSRF has with the proposed wording is that many generating station may not have a “generating station switchyard” as implied by the proposed wording. Often the generator leads (e.g. 20 kV) will exit the generator and connect to transformers located in transformer bays directly adjacent to the plant. From the transformers the now greater than 200 kV lines will be routed to the point of interconnect or a generating unit switchyard, possibly miles or yards away. By no one’s definitions would the transformer bays adjacent to the plant be considered a switchyard. The plant fence may be yards or hundreds of yards from the bays and on a multiple unit site, there may be a site fence or boundary, which could be comprise of fences, security patrols, or other barriers yards or miles from the transformer but enveloping</p>

Organization	Yes or No	Question 3 Comment
		<p>the switchyard. The valid assumption made by the drafting team is that transmission lines within an area tightly controlled by the generator operator poses very little risk to the BES as a result of vegetation contact. This assumption is based on the valid observation that these areas are routinely occupied and observed by station personnel and as a result unexpected and unacceptable vegetation growth is highly unlikely because it is controlled by routine maintenance. It also correctly assumes that some distance past the controlled area is acceptable since this area would also be under near continuous observation. The problem comes in defining both a tightly controlled area and a line of site. We suggest the following: Controlled Area: A perimeter around a power plant, power plants, or switchyard which is prevents intrusion by the use of physical barriers, observation, or electronic monitoring and is routinely occupied such that unexpected and unacceptable vegetation growth would be observed and correct as a matter of routine maintenance. Line of Sight: NSRF recommends a two kilometer distance from the controlled area perimeter. Our assessment is that an individual of average height would have a line of site of approximately 4 Kilometers. Therefore, we recommended a distance of 2 kilometers from the Controlled Area of the plant to provide margin. The revised applicability statement would read as follows: “Generator Owner that owns an overhead transmission line(s) that extends greater than 2.0 kilometers beyond the Controlled Area of the generating station up to the point of interconnection with a Transmission Owner’s Facility and is operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region. Furthermore we applaud the committee for using the metric system to identify the acceptable distance for this standard and urge it to remove all references to English units. We strongly suggest this drafting team and all future drafting team abandon the anachronistic English measurement system. This archaic system, based on the length of an average barley corn, should be abandon in all scientific and engineering endeavors.</p>

**Response:** Thank you for your comment. As it discusses in the document titled [“Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface,”](#) the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the

Organization	Yes or No	Question 3 Comment
<p>overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: “Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”</p>		
<p>Southwest Power Pool Standards Development Team</p>	<p>No</p>	<p>There is a possibility of some conflict with the Bulk Electric System Definition. This should be consistent with the Transmission Owner requirements if the lead is determined part of the BES.</p>
<p><b>Response:</b> Thank you for your comment. The SDT intended this standard to be applied to Facilities of GO and TO equally, with the exception of the distance exemption for a generator interconnection Facility. The SDT also notes that FAC-003-2 (approved by the NERC’s Board of Trustees on Nov. 3, 2011) does not rely upon the BES definition to determine the facility to which this standard applies (200 kV or higher, or IROL or WECC Transfer Path).</p>		
<p>South Carolina Electric and Gas</p>	<p>No</p>	<p>There should be no qualifying exemption to FAC-003 for Generator Owners.</p>
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled “<a href="#">Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface</a>,” the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: “Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”</p>		
<p>SERC Planning Standards Subcommittee</p>	<p>No</p>	<p>We believe there should be no exemption for Generator Owners.</p>



Organization	Yes or No	Question 3 Comment
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled "<a href="#">Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface</a>," the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: "Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are..."</p>		
PSEG	No	
Infigen Energy US	Affirmative	Infigen finds the DST supporting details regarding FAC-003-X to be appropriate. We support maintaining "reasonable and appropriate" risk prevention measures to minimize encroachment that could trigger vegetation-related outages.
<p><b>Response:</b> Thank you for your comment and support.</p>		
Seattle City Light	Affirmative	Key points are the greater than one mile with clear statement of "...beyond the fenced area of the generating switchyard."
<p><b>Response:</b> Thank you for your comment and support.</p>		
RES Americas Development / American Wind Energy Association	Yes	Applying the vegetation management requirements to only generator lead lines that extend more than "one mile beyond the fenced area of the generating station switchyard" strikes a reasonable balance among the many stakeholder positions expressed on this topic. We think that as this criterion recognizes that there is little need for a vegetation management plan for shorter lines, it should explicitly state that this is true for all such facilities with lines of that length or smaller.
<p><b>Response:</b> Thank you for your comment and support.</p>		

Organization	Yes or No	Question 3 Comment
Texas Reliability Entity	Yes	In the description of the “second effective date” in FAC-003-X there is an erroneous reference to “Requirement R3,” which should be corrected to “Requirement R1.”
<p><b>Response:</b> Thank you for your comment and support. This conforming change was made.</p>		
Seattle City Light	Yes	Key points are the greater than one mile with clear statement of “...beyond the fenced area of the generating switchyard.”
<p><b>Response:</b> Thank you for your comment and support.</p>		
ACES Power Marketing Standards Collaborators	Yes	<p>We support the changes to FAC-003 suggested by the drafting team because we believe the drafting team has provided the best solution in face of a difficult problem. However, in general, we do not support registration of GOs and GOPs as TOs and TOPs or applicability of any TO/TOP requirements to the GO/GOP simply because they have a radial interconnection greater than one mile in length. While there may be some generators that own interconnecting facilities of significant length operated at a significant voltage that could impact BES reliability, we do not believe that the number of generating facilities that fit into that category is significantly large. When one considers that the majority of generators are still owned and operator by utilities that are also registered as a TO and TOP, there is only a minority subset of generators left that could be considered. NERC has the registration for this remaining set of generators and could use the data to evaluate how many of this remaining subset have interconnections owned by the generator that are substantial enough to affect reliability. It seems that NERC could determine the boundaries of this problem before registering anymore GOs and GOPs as TOs and TOPs or before applying additional requirements through this effort on the GOs and GOPs.</p>
<p><b>Response:</b> Thank you for your comment and support.</p>		

Organization	Yes or No	Question 3 Comment
SERC OC Standards Review Group	Yes	
Southwest Power Pool Regional Entity	Yes	
Florida Municipal Power Agency	Yes	
PPL NERC Registered Affiliates	Yes	
Electric Power Supply Association	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
American Transmission Company	Yes	
Sempra Generation	Yes	

Organization	Yes or No	Question 3 Comment
Entergy Services	Yes	
Xcel Energy	Yes	
Cowlitz County PUD	Yes	
Constellation Power Source Generation	Yes	
Western Electricity Coordinating Council		
Puget Sound Energy, Inc.		
Compliance & Responsibility Organization		
Bonneville Power Administration		
Consolidated Edison Co. of NY, Inc.		
ReliabilityFirst		
Tennessee Valley Authority		

**4. Do you support compliance timeframe for Generator Owners as included and explained in the Implementation Plans for FAC-003-X?**

**Summary Consideration:**

The SDT thanks all stakeholders for their comments. The vast majority of stakeholders support the compliance timeframes as proposed and explained in the Implementation Plan for FAC-003-X.

One commenter found a typo in the effective dates section of FAC-003-X, where one section referenced R3 when it should have referenced R1. That has been corrected in both the standard and the Implementation Plan.

A few stakeholders thought that two years was too long for an Implementation Plan for this standard. The SDT reminded those commenters that the time frame was based on previous stakeholder comments and the fact that the Implementation Plan for Version 0 standards stated “the Version 0 Reliability Standards are generally a translation and clarification of existing operating policies and planning standards, entities that are in compliance with NERC policies and standards today are expected to be able to remain in compliance with the Version 0 Reliability Standards with their existing procedures, tools, and practices.” This process occurred over more than two years. It is therefore reasonable to assume that GOs, having never had to comply with a vegetation management standard, be afforded adequate time to do so.

Beyond the corrected typo, no changes were made.

Organization	Yes or No	Question 4 Comment
Ameren Services	Negative	The 2 year compliance time line is far too long. There is significant industry evidence that was developed in the drafting of Version 2 that supports a one year compliance time-line for new lines. This is evidenced in Version 2. Thus there is no basis for the 2 years.
<p><b>Response:</b> Thank you for your comment. The SDT choose the time in the implementation plan based upon comments of stakeholders and the fact that the implementation plan for <u>Version 0 standards</u> stated “the Version 0 Reliability Standards are generally a translation and clarification of existing operating policies and planning standards, entities that are in compliance with NERC policies</p>		

Organization	Yes or No	Question 4 Comment
<p>and standards today are expected to be able to remain in compliance with the Version 0 Reliability Standards with their existing procedures, tools, and practices.” This process occurred over more than two years. It is therefore reasonable to assume that GOs, having never had to comply with a vegetation management standard, be afforded adequate time to do so.</p>		
<p>Texas Reliability Entity</p>	<p>No</p>	<p>A compliance timeframe for the applicable GOs of two years is too long and the scenario used as a basis provides no timing specifics or details. Moreover, the 12 months for an existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard is arguably the same situation as an applicable GO but the applicable GO has an additional 12 months to come into compliance.</p>
<p><b>Response:</b> Thank you for your comment. The SDT choose the time in the implementation plan based upon comments of stakeholders and the fact that the implementation plan for <a href="#">Version 0 standards</a> stated “the Version 0 Reliability Standards are generally a translation and clarification of existing operating policies and planning standards, entities that are in compliance with NERC policies and standards today are expected to be able to remain in compliance with the Version 0 Reliability Standards with their existing procedures, tools, and practices.” This process occurred over more than two years. It is therefore reasonable to assume that GOs, having never had to comply with a vegetation management standard, be afforded adequate time to do so. The SDT does not believe that a TO’s acquisition of a new asset is the same as applying new requirements to a GO.</p>		
<p>Ingleside Cogeneration LP (Occidental Chemical)</p>	<p>No</p>	<p>Based upon similar issues addressed in Compliance Application Notices (CANs), the drafting team needs to specify when the first vegetation management inspection quarterly report, and any other requirement with an assigned interval in FAC-003-3 or FAC-003-X. Even if the decision is to adopt the same criteria proposed in CAN-0012, the industry is better served with a clear distinction made up front.</p>
<p><b>Response:</b> Thank you for your comment. This is a comment that is outside the scope of the SDT, and in fact deals with a larger body of standards than just FAC-003. No change made.</p>		
<p>PSEG</p>	<p>No</p>	<p>It’s no longer applicable.</p>
<p><b>Response:</b> Thank you for your comment. The SDT acknowledges that in November 2011, NERC’s Board of Trustees adopted FAC-003-2</p>		

Organization	Yes or No	Question 4 Comment
<p>– Transmission Vegetation Management (developed under Project 2007-07 Vegetation Management). Based on this approval, NERC staff will file FAC-003-2 with the applicable regulatory authorities. The Project 2010-07 SDT will move forward with ballots for both FAC-003-3 (proposed changes to the BOT-adopted FAC-003-2) and FAC-003-X (proposed changes to the FERC-approved FAC-003-1) with the intention of eventually only filing FAC-003-3. The SDT has elected to carry FAC-003-X through to ballot because if FAC-003-2 and FAC-003-3 are not approved by FERC, the SDT wants to be ready to file FAC-003-X to ensure that there is a functional entity responsible for managing vegetation on the piece of line commonly known as the generator interconnection Facility.</p> <p>Note that for its recirculation ballot, the SDT will be balloting <b>both</b> FAC-003-3 and FAC-003-X, but stakeholders should <b>not</b> vote as though they are choosing one or the other. As stated above, the SDT plans to present FAC-003-3 alone to NERC’s Board of Trustees, but it wants to have FAC-003-X ready to submit to the Board if, for some reason, neither FAC-003-2 nor FAC-003-3 are approved by FERC. Members of the ballot body should vote on the merits of each version of FAC-003 individually. <b>In other words, stakeholders who support adding GOs to the applicability of FAC-003 should vote in the affirmative for both FAC-003-3 and FAC-003-X.</b></p>		
Manitoba Hydro	No	See question 3 comments.
<p><b>Response:</b> See the SDT’s response to Question 3.</p>		
Southwest Power Pool Standards Development Team	No	The effective dates should be consistent with the original standard. If there is a reason for the extension we would like to know why.
<p><b>Response:</b> Thank you for your comment. The SDT choose the time in the implementation plan based upon comments of stakeholders and the fact that the implementation plan for <a href="#">Version 0 standards</a> stated “the Version 0 Reliability Standards are generally a translation and clarification of existing operating policies and planning standards, entities that are in compliance with NERC policies and standards today are expected to be able to remain in compliance with the Version 0 Reliability Standards with their existing procedures, tools, and practices.” This process occurred over more than two years. It is therefore reasonable to assume that GOs, having never had to comply with a vegetation management standard, be afforded adequate time to do so.</p>		
Southern Company	Yes	The development of a working TVMP will take some time to initialize. The 1 year time frame for R3 is appropriate. The 2 year time frame for all other requirements is appropriate.

Organization	Yes or No	Question 4 Comment
<b>Response:</b> Thank you for your comment and support.		
Seattle City Light	Yes	The explanation deals with the fact that there are simultaneous revisions of FAC-003 underway by two different teams.
<b>Response:</b> Thank you for your comment and support.		
MRO NSRF	Yes	There may be a typographical error on the effective date. As currently drafted the standard states: In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption. Should it be worded as follows? In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 R1 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.
<b>Response:</b> Thank you for your comment. The SDT agrees with you. "Requirement R3," will be corrected to "Requirement R1."		
RES Americas Development/ American Wind Energy Association	Yes	Yes, as with our comments to question 2, since there is no exigent reason why this standard needs to be put in place at once, we support the proposed compliance timeframe. We believe that it will allow generators a reasonable time to comply with the requirement.



Organization	Yes or No	Question 4 Comment
<b>Response:</b> Thank you for your comment and support.		
SERC OC Standards Review Group	Yes	
Northeast Power Coordinating Council, Northeast Power Coordinating Council	Yes	
Southwest Power Pool Regional Entity	Yes	
SERC Planning Standards Subcommittee	Yes	
Florida Municipal Power Agency	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Electric Power Supply Association	Yes	
American Electric Power	Yes	
BP Wind Energy North	Yes	

Organization	Yes or No	Question 4 Comment
America Inc.		
Exelon	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
American Transmission Company	Yes	
South Carolina Electric and Gas	Yes	
Sempra Generation	Yes	
Entergy Services	Yes	
Xcel Energy	Yes	
Cowlitz County PUD	Yes	
Constellation Power Source Generation	Yes	
Western Electricity Coordinating Council		

Organization	Yes or No	Question 4 Comment
Puget Sound Energy, Inc.		
Compliance & Responsibility Organization		
Bonneville Power Administration		
Consolidated Edison Co. of NY, Inc.		
ReliabilityFirst		
Tennessee Valley Authority		

5. In the FAC-003-3 implementation plan, the SDT has attempted to account for a number of different scenarios that could play out with respect to the filing and approvals of FAC-003-2 and FAC-003-3. Do you support this approach? If there are other scenarios that the SDT needs to account for, please suggest them here.

#### Summary Consideration:

The SDT thanks all stakeholders for their comments. The vast majority of stakeholders support the compliance timeframes as proposed and explained in the Implementation Plan for FAC-003-3.

One commenter thought that two years was too long for an Implementation Plan for this standard. The SDT reminded those commenters that the time frame was based on previous stakeholder comments and the fact that the Implementation Plan for Version 0 standards stated “the Version 0 Reliability Standards are generally a translation and clarification of existing operating policies and planning standards, entities that are in compliance with NERC policies and standards today are expected to be able to remain in compliance with the Version 0 Reliability Standards with their existing procedures, tools, and practices.” This process occurred over more than two years. It is therefore reasonable to assume that GOs, having never had to comply with a vegetation management standard, be afforded adequate time to do so.

Some stakeholders expressed confusion about the relationship between FAC-003-3 and the recently BOT-approved FAC-003-2. The SDT acknowledges that in November 2011, NERC’s Board of Trustees adopted FAC-003-2 – Transmission Vegetation Management (developed under Project 2007-07 Vegetation Management). Based on this approval, NERC staff will file FAC-003-2 with the applicable regulatory authorities. The Project 2010-07 SDT will move forward with ballots for both FAC-003-3 (proposed changes to the BOT-adopted FAC-003-2) and FAC-003-X (proposed changes to the FERC-approved FAC-003-1) with the intention of eventually only filing FAC-003-3. The SDT has elected to carry FAC-003-X through to ballot because if FAC-003-2 and FAC-003-3 are not approved by FERC, the SDT wants to be ready to file FAC-003-X to ensure that there is a functional entity responsible for managing vegetation on the piece of line commonly known as the generator interconnection Facility.

All stakeholders should note that for its recirculation ballot, the SDT will be balloting **both** FAC-003-3 and FAC-003-X, but stakeholders should **not** vote as though they are choosing one or the other. As stated above, the SDT plans to present FAC-003-3 alone to NERC’s Board of Trustees, but it wants to have FAC-003-X ready to submit to the Board if, for some reason, neither FAC-003-2 nor FAC-003-3 are approved by FERC. Members of the ballot body should vote on the merits of each version of FAC-003 individually. **In other words, stakeholders who support adding GOs to the applicability of FAC-003 should vote in the affirmative for both FAC-003-3 and FAC-003-X.**

Organization	Yes or No	Question 5 Comment
Manitoba Hydro	No	See question 3 comments.
<b>Response:</b> See the SDT’s response to Question 3.		
Southern Company	No	We believe that a standard development process should not have parallel paths where the same version is being modified by multiple teams. The uncertainty in which development path leads to confusion in the industry and ultimately proves to have wasted some resources for the path that does not come to fruition.
<p><b>Response:</b> Thank you for your comment. While the SDT agrees this is not preferable, it was necessary given the urgency of both projects. The SDT did the best it could to describe the scenarios and reasons for posting multiple versions.</p> <p>In November 2011, NERC’s Board of Trustees adopted FAC-003-2 – Transmission Vegetation Management (developed under Project 2007-07 Vegetation Management). Based on this approval, NERC staff will file FAC-003-2 with the applicable regulatory authorities. The Project 2010-07 SDT will move forward with ballots for both FAC-003-3 (proposed changes to the BOT-adopted FAC-003-2) and FAC-003-X (proposed changes to the FERC-approved FAC-003-1) with the intention of eventually only filing FAC-003-3. The SDT has elected to carry FAC-003-X through to ballot because if FAC-003-2 and FAC-003-3 are not approved by FERC, the SDT wants to be ready to file FAC-003-X to ensure that there is a functional entity responsible for managing vegetation on the piece of line commonly known as the generator interconnection Facility.</p>		
Ingleside Cogeneration LP (Occidental Chemical)	Yes	Ingleside Cogeneration agrees that the SDT’s approach is thorough. We are far more concerned about FAC-003’s applicability criteria and implementation time frame at this point - as stated in our responses to questions 3 and 4.
<b>Response:</b> Thank you for your comment and support. Please refer to the SDT’s responses to Questions 3 and 4.		
ACES Power Marketing Standards Collaborators	Yes	With recent NERC BOT approval of the FAC-003-2 standard, the drafting team should continue to monitor the standard progress with FERC and make necessary adjustments to the implementation plan.
<b>Response:</b> Thank you for your comment. The SDT acknowledges that FAC-003-2 was recently approved by the BOT. The SDT does not		

Organization	Yes or No	Question 5 Comment
<p>see the need to revise the GO implementation plan, as it already accounts for a number of scenarios that could occur based on how FERC handles the filing of FAC-003-2.</p>		
<p>Ameren</p>		<p>(a) There is no technical basis for the one mile length exemption. In fact, one could argue that a very short line, 300 feet in length, that experienced a fault from a tree at "the end of the circuit", i.e near the switchyard fence, would have much more of an impact on the BES because the fault would be limited by much less impedance.</p> <p>(b) It is also unclear in this version if a GO that owned one line that was 1.2 miles in length would have to comply for the entire length of said line, or just 0.2 miles of said line. If the GO is responsible for 1.2 miles, then that argues that the first mile is important and consequently there is no basis for ignoring the first mile on other lines. If the GO is only responsible for 0.2 miles, what is the technical basis to ignore a mile? And would it be the first mile from the switchyard that is ignored, or is the middle mile, or the last mile where it connects to the TO? Or could the GO decide? Or could the GO pick sections of the line that amount to a mile that they can ignore? This seems like something that should be addressed for compliance.</p> <p>(c) The 2 year compliance time line is far too long. There is significant industry evidence that was developed in the drafting of Version 2 that supports a one year compliance time-line for new lines. This is evidenced in Version 2. Thus there is no basis for the 2 years</p>
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled "<a href="#">Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface</a>," the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: "Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are..."</p> <p>With respect to your second comment, the SDT intended for the length qualifier to be just that; if the overhead portion of a Facility</p>		

Organization	Yes or No	Question 5 Comment
<p>exceeds the distance, <a href="#">the entire Facility</a> is subject to the requirements of the standard.</p> <p>The SDT choose the time in the implementation plan based upon reasons it documented in the <a href="#">accompanying implementation plan</a> and also based upon comments of stakeholders.</p>		
PSEG	Yes	
SERC OC Standards Review Group	Yes	
Southwest Power Pool Standards Development Team	Yes	
Northeast Power Coordinating Council, Northeast Power Coordinating Council	Yes	
MRO NSRF	Yes	
SERC Planning Standards Subcommittee	Yes	
Florida Municipal Power Agency	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
Electric Power Supply Association	Yes	

Organization	Yes or No	Question 5 Comment
American Wind Energy Association	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Exelon	Yes	
Seattle City Light	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
American Transmission Company	Yes	
South Carolina Electric and Gas	Yes	
RES Americas Development	Yes	
Sempra Generation	Yes	
Entergy Services	Yes	



Organization	Yes or No	Question 5 Comment
Xcel Energy	Yes	
Cowlitz County PUD	Yes	
Texas Reliability Entity	Yes	
Constellation Power Source Generation	Yes	
Tennessee Valley Authority	Yes	
Southwest Power Pool Regional Entity		
Western Electricity Coordinating Council		
Puget Sound Energy, Inc.		
Compliance & Responsibility Organization		
Bonneville Power Administration		
Consolidated Edison Co. of NY, Inc.		
ReliabilityFirst		

6. In its technical justification document, the SDT reviews all standards that had been proposed for substantive modification in the Ad Hoc Group’s original support and explains why, with the exception of FAC-003, modifying them would not provide any reliability benefit. Do you support these justifications? If you believe the SDT needs to add more information to its rationale for any of these decisions, please include suggested language here.

**Summary Consideration:**

The SDT thanks all stakeholders for their comments.

A few commenters pointed out that the wording in R1 and R2 of PRC-005-1a requires the same explicit reference to a generator interconnection Facility that was added in PRC-004-2a R2. The SDT is developing revisions to PRC-005-1a and will post them soon.

Many commenters encouraged the SDT to reexamine the standards and requirements that FERC and NERC applied to GOs and GOPs in their Milford/Cedar Creek order and draft compliance directive regarding generator leads. The SDT pointed out that the NERC Standard Processes Manual does not address the issue of how to deal with FERC Orders (that don’t include explicit directives), or NERC directives, within the standards process, and until this round of comments, when NERC staff submitted comments, the SDT had no formal mandate that would have made it appropriate to consider the content of the proposed directive.

Based on stakeholder comments, the SDT expanded its technical justification document (posted under “Supporting Materials”) to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.

One commenter remains concerned about the scope of the SDT. The SDT reminded this commenter that its scope is addressed in the SAR and that its intent is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT also refers the commenter to the document titled Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document. Specifically, see the last paragraph on page 4 and first two on page 5.

Organization	Yes or No	Question 6 Comment
Manitoba Hydro	Negative	The intention of the NERC SDT in revising these standards is not clear. While the Technical Justification document states that the SDT intended to focus on a Generator

Organization	Yes or No	Question 6 Comment
		<p>Owner’s radial interconnection facilities, the scope of the revised standard (s) is not confined to such facilities. The very broadly defined term “Facility” is used. Moreover, the Technical Justification document’s reference to the FERC decision in Cedar Creek as a basis for the revision of additional standards is confusing, since that decision did not specifically address the issue of radial facilities and supported NERC’s registration of GOs as TOs.</p>
<p><b>Response:</b> Thank you for your comment. The scope of this SDT is addressed in the <a href="#">SAR</a>. The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT determined that it should first address “low-hanging fruit” and believes these to be sole-use Facilities (see posted examples under “Supporting Materials”) – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP). Through our deliberations, we came to the conclusion that an interconnection Facility owned or operated by a GO or GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT.</p> <p>The SDT also refers the commenter to the document titled <a href="#">Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document</a>. Specifically, see the last paragraph on page 4 and first two on page 5.</p>		
Texas Reliability Entity	No	<p>Our negative votes on FAC-003 reflect our concern that this project has not considered all of the applicable standards. Why did the SDT choose to only review the Ad Hoc Group’s standards when there have been multiple registration appeals in which FERC and NERC have repeatedly cited specific additional TO/TOP standards that were determined to be applicable to GO/GOPs? This SDT project would serve a tremendous value to the ERO and in particular industry if it were to address the technical aspects of the following FERC ordered applicable standards: PRC-001-1 R2, R4; PRC-004-1 R1; TOP-004-2 R6; PER-003-1 R1; FAC-003-1 R1, R2; TOP-001-1a R1 and FAC-004-2 R2. The SDT team should analyze the FERC orders, the applicable standards indicated, and the circumstances and facts involved, and technically justify why no reliability gap exists if these standards are not applied to GO interface facilities. The SDT should include more “technical” information in its technical justification document. For example, in regards to TOP-004-2 R7, the SDT technical</p>

Organization	Yes or No	Question 6 Comment
		<p>justification states that there is no reliability gap because, “. . . because an operator has a fiduciary obligation to protect a Facility for which it is operationally responsible.” An entity having a fiduciary obligation is not a technical justification of why a reliability gap does not exist. Moreover, by that logic there would be no need for many standards because every registered entity has a fiduciary obligation to protect its facilities.</p>
<p><b>Response:</b> Thank you for your comment. The NERC <a href="#">Standard Processes Manual</a> does not address the issue of how to deal with FERC Orders (that don’t include explicit directives), or NERC directives, within the standards process, and until this round of comments, when NERC staff submitted comments, the SDT had no formal mandate that would have made it appropriate to consider the content of the directive you reference.</p> <p>We would like to clarify, in response to the comment concerning TOP-004-2 R7, that in the document titled “<a href="#">Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface</a>” the SDT also stated “FAC-008-1—Facility Ratings Methodology and FAC-009-1—Establish and Communicate Facility Ratings already infer that the reason for establishing a ratings methodology and communicating facility ratings to the Reliability Coordinator, Planning Authority, Transmission Planner, and Transmission Operator is for use in reliable planning and operation of the Bulk Electric System.”</p> <p>Based on your and other comments, we have expanded our technical justification document (posted under “Supporting Materials”) to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.</p>		
PSEG	No	<p>PRC-005-1 - Transmission and Generation Protection System Maintenance and Testing was recommended by the Ad Hoc Group for modification, but not addressed to the technical justification document. It should be.</p>
<p><b>Response:</b> Thank you for your comment. We have reviewed PRC-005-1a and believe that the wording in R1 and R2 of that standard require the same explicit reference to a generator interconnection Facility that was added in PRC-004-2a R2. The SDT is developing revisions to PRC-005-1a and will post them soon.</p>		
Florida Municipal Power	No	see comment to Question 7

Organization	Yes or No	Question 6 Comment
Agency		
<b>Response:</b> See the SDT’s response to Question 7.		
Manitoba Hydro	No	See Question 7 comments.
<b>Response:</b> See the SDT’s response to Question 7.		
MRO NSRF	No	The NSRF has one concern with the current justification and definitions. At some point, if enough interconnections are made to generator outlet leads in accordance with FAC-001, the original generator operator will be a Transmission Operator and a Transmission Owner. This point in time needs to be explicitly defined by the drafting team.
<b>Response:</b> The SDT cannot act on this comment. Registration is outside the scope of this SDT and resides with NERC and the Regional Entity.		
Manitoba Hydro		If the drafting team intends to limit the scope of FAC-001-1 to GO owned radial generator interconnection facilities that are not deemed BES transmission and therefore would not require the registration of the GO as a TO, Manitoba Hydro disagrees with the proposed changes to FAC-001-1 as Generator Owners may not have the models or expertise to perform interconnection studies to determine if there is an impact on the Transmission Network. This concern is echoed in the technical justification document provided by NERC: ‘the SDT acknowledges that the Generator Owner may not, at the time it agrees or is compelled to allow a third part to interconnect, have the necessary expertise to conduct the required interconnect studies to meet this standard... the Generator Owner will have to acquire such expertise. How the Generator Owner chooses to do so is not for the SDT to determine.’ Although it may not be for the SDT to determine how a GO obtains technical expertise, ensuring that such expertise is acquired before a GO conducts the required interconnection studies should be a concern to NERC as this directly affects

Organization	Yes or No	Question 6 Comment
		<p>the reliability of the BES. As a result, all interconnection requests should be implemented by the TO providing the GO with connection to the BES regardless if the interconnection point is within a Generation Owner facility or End-User facility as the TO is in the best position to set unbiased connection requirements to ensure the reliability of the BES is maintained. If the scope of FAC-001-1 also applies to GO owned BES transmission facilities, Manitoba Hydro strongly believes that the Compliance Registry should apply and the GOs should be required to register as a TO and abide by all applicable standards to that functional type. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. Reliability gaps would be better addressed if select GOs and GOPs registered as TOs and TOPs to ensure all reliability standards, including the protection standards, are met so the reliability of the BES is maintained. At this time, this would not lead to a large number of extra registrations since, as stated in the technical justification document, ‘interconnection requests for Generator Owner Facilities are still relatively rare.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees this is a complex issue and did its best to outline how it arrived at its position in the document titled <a href="#">“Technical Justification: FAC-001-1.”</a></p> <p>The SDT points out that if the GO is part of an RTO, then the GO will be coordinating any interconnection studies either directly or indirectly with the RTO interconnection process. If the GO is not part of an RTO, then the GO will be required to follow the pro forma interconnection procedures from Order 2003. The Order 2003 procedures require the GO to coordinate any studies with an affected system which could include Facilities owned by one, or more, TO on the other side of the GO’s existing point of interconnection.</p> <p>The SDT has proposed the modification of a select set of standards so that they apply to GOs and GOPs as an alternative to registering all GOs and GOPs as TOs and TOPs. The SDT does agree that upon interconnection of a third party, other standards or registrations may apply as appropriate.</p>		
Electric Power Supply Association	Affirmative	<p>All TO requirements for FAC-001-1 would apply if and when GO executes an Agreement to evaluate the reliability impact of interconnecting a third party Facility to its existing generation interconnection Facility. The execution of the agreement is necessary to comply with FAC-002-1 and start the compliance clock with the</p>

Organization	Yes or No	Question 6 Comment
		<p>applicable regulatory authority. Thus as the Project 2010-07 Standard Drafting Team (SDT) in its technical justification has stated, “If, and only if, the existing owner of a generator interconnection Facility has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to its existing generation Facility” then FAC-001-1 should apply. EPSA concurs with SDT’s conclusion. The SDT has examined the issue regarding if future requests for transmission service on the interconnection Facility and in doing so acknowledged that when that Facility adopted open access and was providing transmission service it would necessitate re-evaluation of the need for the Facility to be maintained in accordance with FAC-001-1, Requirements 2 and 4. This service would indeed prompt the necessary agreement the SDT contemplates in its technical justification of FAC-001-1. EPSA believes this serves as the necessary trigger for evaluation of Requirements 2 and 4 under FAC-001-1 for GOs.</p>
<p><b>Response:</b> Thank you for your comment and support.</p>		
<p>Infigen Energy US</p>	<p>Affirmative</p>	<p>Infigen supports the FAC-001-1 technical analysis by the Project 2010-07 SDT, which states in part that “If, and only if, the existing owner of a generator interconnection Facility has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to its existing generation Facility would the proposed FAC-001-1 apply”. We agree with the SDT’s reasoning that if the owner of the existing generator interconnection Facility agrees, or is compelled to allow a third party to interconnect, but can do so using existing agreements, contracts, and/or tariffs [to avoid requiring additional executed Agreement(s)], this is the most prudent and effective way to manage this process with continuity. In order to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility more expediently, it can avoid having to develop its own connection requirements or perform additional impact studies, to the extent possible. We find it reasonable to negotiate with the existing Transmission Owner, Transmission Planner, and/or Transmission Service Provider to manage this requirement, utilizing their</p>

Organization	Yes or No	Question 6 Comment
		existing processes and Agreements for the purpose of fulfilling FAC-001-1.
<p><b>Response:</b> Thank you for your comment and support.</p>		
Southern Company	Yes	Additional responses are needed to justify the exclusion of the list of requirements and standards found in the recent FERC order denying the rehearing request of the Compliance Registry Appeals of Cedar Creek and Milford. (135 FERC Para. 61,241). Please see our response to Question 10 for a detailed discussion on this topic.â€,â€,â€,
<p><b>Response:</b> Thank you for your comment. The NERC <a href="#">Standard Processes Manual</a> does not address the issue of how to deal with FERC Orders (that don't include explicit directives), or NERC directives, within the standards process, and until this round of comments, when NERC staff submitted comments, the SDT had no formal mandate that would have made it appropriate to consider the content of the directive you reference.</p> <p>Based on your and other comments, we have expanded our technical justification document (posted under "Supporting Materials") to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.</p>		
Constellation Power Source Generation	Yes	Constellation supports the SDT justifications and offers additional information in our response to question 10.
<p><b>Response:</b> Thank you for your comment and support.</p>		
Ingleside Cogeneration LP (Occidental Chemical)	Yes	Ingleside Cogeneration LP believes the SDT has spent a significant amount of time and effort to demonstrate that only FAC-001, FAC-003, and PRC-004 need to be modified to address any reliability gaps that may exist related to the GO-TO interconnection. We agree that the other standards/requirements identified by the Ad Hoc Group are covered elsewhere.
<p><b>Response:</b> Thank you for your comment and support.</p>		



Organization	Yes or No	Question 6 Comment
American Wind Energy Association	Yes	The reasoning of the SDT is comprehensive and makes a strong case for why there is no need for additional standards to be applied to GO/GOP lead lines as they will not improve the reliability of the Bulk Electric System. In fact, as noted above, such additional standards may decrease reliability by diverting the GO/GOP's resources from the operation of the equipment that actually produces electricity - the generation equipment itself.
<b>Response:</b> Thank you for your comment and support.		
RES Americas Development	Yes	The reasoning of the SDT is comprehensive and makes a strong case for why there is no need for additional standards to be applied to GO/GOP lead lines as they will not improve the reliability of the Bulk Electric System. In fact, as noted above, such additional standards may decrease reliability by diverting the GO/GOP's resources from the operation of the equipment that actually produces electricity - the generation equipment itself.
<b>Response:</b> Thank you for your comment and support.		
SERC OC Standards Review Group	Yes	
Southwest Power Pool Standards Development Team	Yes	
Northeast Power Coordinating Council, Northeast Power Coordinating Council	Yes	
Southwest Power Pool Regional Entity	Yes	

Organization	Yes or No	Question 6 Comment
SERC Planning Standards Subcommittee	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Electric Power Supply Association	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Exelon	Yes	
Seattle City Light	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
American Transmission Company	Yes	
South Carolina Electric and	Yes	

Organization	Yes or No	Question 6 Comment
Gas		
Sempra Generation	Yes	
Xcel Energy	Yes	
Cowlitz County PUD	Yes	
Western Electricity Coordinating Council		
Puget Sound Energy, Inc.		
Compliance & Responsibility Organization		
Bonneville Power Administration		
Independent Electricity System Operator		
Ameren		
Consolidated Edison Co. of NY, Inc.		
Entergy Services		
ReliabilityFirst		

Organization	Yes or No	Question 6 Comment
Tennessee Valley Authority		

**7. The SDT is attempting to modify a set of standards so that radial generator interconnection Facilities are appropriately accounted for in NERC's Reliability Standards, both to close reliability gaps and to prevent the unnecessary registration of GOs and GOPs at TOs and TOPs. Does the set of standards currently posted achieve this goal?**

**Summary Consideration:**

The SDT thanks all stakeholders for their comments. Most commenters support the SDT's work and agree that the set of standards for which the SDT has proposed modification ensure that radial generator interconnection Facilities are appropriately accounted for in NERC's Reliability Standards.

One commenter continues to express confusion about the scope of the SDT's work in general. The SDT reminded this commenter that its scope is addressed in the [SAR](#). The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT determined that it should first address "low-hanging fruit" and believes these to be sole-use Facilities (see posted examples under "Supporting Materials") – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP). Through its deliberations, the SDT came to the conclusion that an interconnection Facility owned or operated by a GO or GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT. The SDT also refers the commenter to the document titled [Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document](#) (specifically, the last paragraph on page 4 and first two on page 5). The SDT has proposed the modification of a select set of standards so that they apply to GOs and GOPs as an alternative to registering all GOs and GOPs as TOs and TOPs, a strategy that has been widely supported by the stakeholder body. The SDT does agree that upon interconnection of a third party, other standards or registrations may apply as appropriate.

One commenter asked the SDT to specify what it means by "radial." By "radial generator interconnection Facilities," the SDT means sole-use Facilities (see posted examples under "Supporting Materials") – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP).

A few commenters suggested that the SDT address those standards cited by FERC and NERC in related projects. The SDT pointed out that the NERC [Standard Processes Manual](#) does not address the issue of how to deal with FERC Orders (that don't include explicit directives), or NERC directives, within the standards process. However, based on stakeholder comments, the SDT has expanded its technical justification document (posted under "Supporting Materials") to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.

One commenter suggested that the SDT include the GO in TOP-004-2 R6, but the SDT continues to maintain that no gap exists because TOP-002-2 R3 already requires the GO to coordinate with its host BA and TSP, who in turn are required to coordinate with their TOPs.

One commenter pointed out that the Data Retention section of the proposed PRC-004-2.1a also requires modification to include the generator interconnection Facility. The SDT agrees and made this change.

Organization	Yes or No	Question 7 Comment
Manitoba Hydro	Negative	<p>Manitoba Hydro has the following comments:</p> <p>1) The intention of the NERC SDT in revising these standards is not clear. While the Technical Justification document states that the SDT intended to focus on a Generator Owner’s radial interconnection facilities, the scope of the revised standard (s) is not confined to such facilities. The very broadly defined term “Facility” is used. Moreover, the Technical Justification document’s reference to the FERC decision in Cedar Creek as a basis for the revision of additional standards is confusing, since that decision did not specifically address the issue of radial facilities and supported NERC’s registration of GOs as TOs.</p> <p>2) Manitoba Hydro strongly disagrees with bypassing the NERC Compliance Registry and only having a limited set of standards apply to the GOs ‘interconnection facilities’ If a Generator Owner wants to own transmission facilities and it falls under the definition of a Transmission Owner under the NERC Registry Criteria, then all the Requirements applicable to a TO should apply. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. Reliability gaps would be better closed if select GOs and GOPs simply registered as TOs and TOPs. At this time, this would not lead to a large number of extra registrations since, as stated in the technical justification document, ‘interconnection requests for Generator Owner Facilities are still relatively rare.</p>
<p><b>Response:</b> Thank you for your comment. The scope of this SDT is addressed in the <a href="#">SAR</a>. The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT determined that it should first address “low-hanging fruit” and believes these to be sole-use Facilities (see posted examples under</p>		

Organization	Yes or No	Question 7 Comment
<p>“Supporting Materials”) – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP). Through our deliberations, we came to the conclusion that an interconnection Facility owned or operated by a GO or GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT.</p> <p>The SDT also refers the commenter to the document titled <a href="#">Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document</a>. Specifically, see the last paragraph on page 4 and first two on page 5.</p> <p>The SDT has proposed the modification of a select set of standards so that they apply to GOs and GOPs as an alternative to registering all GOs and GOPs as TOs and TOPs, a strategy that has been widely supported by the stakeholder body. The SDT does agree that upon interconnection of a third party, other standards or registrations may apply as appropriate.</p>		
Manitoba Hydro	Negative	<p>Manitoba Hydro strongly disagrees with bypassing the NERC Compliance Registry and only having a limited set of standards apply to the GOs ‘interconnection facilities’ If a Generator Owner wants to own transmission facilities and it falls under the definition of a Transmission Owner under the NERC Registry Criteria, then all the Requirements applicable to a TO should apply. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. Reliability gaps would be better closed if select GOs and GOPs simply registered as TOs and TOPs. At this time, this would not lead to a large number of extra registrations since, as stated in the technical justification document, ‘interconnection requests for Generator Owner Facilities are still relatively rare.</p>
<p><b>Response:</b> Thank you for your comment. The SDT has proposed the modification of a select set of standards so that they apply to GOs and GOPs as an alternative to registering all GOs and GOPs as TOs and TOPs, a strategy that has been widely supported by the stakeholder body. The SDT does agree that upon interconnection of a third party, other standards or registrations may apply as appropriate.</p>		
PSEG	No	<p>It would be helpful if the SDT defined what it means by the term “radial generator interconnection Facilities.” Does it mean interconnection Facilities that under Normal Clearing for a fault do not interrupt flows on other BES Elements? This is also confusing because of the radial exclusion included in the BES definition work in</p>

Organization	Yes or No	Question 7 Comment
		Project 2010-17. That definition would allow part of a three-terminal circuit to be excluded from the BES, while the other parts are included in the BES.
<p><b>Response:</b> Thank you for your comment. By “radial generator interconnection Facilities,” the SDT means sole-use Facilities (see posted examples under “Supporting Materials”) – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP). Through our deliberations, we came to the conclusion that an interconnection Facility owned or operated by a GO/GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT.</p>		
Texas Reliability Entity	No	See comment 6.
<p><b>Response:</b> See the SDT’s response to Question 6.</p>		
Manitoba Hydro	No	<p>The SDT’s proposed modifications gives special treatment to the Generator Owner in that it allows the Generator Owner TO status for a couple of standards (FAC-001, FAC-003 and PRC-004), but exempts the Generator Owner from many of the standards applicable to a TO. The NERC Registry Criteria defines the various functional entities. If a Generator Owner wants to own transmission facilities and it falls under the definition of a Transmission Owner under the NERC Registry Criteria, then all the Requirements applicable to a TO should apply. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. Reliability gaps would be better closed if select GOs and GOPs simply registered as TOs and TOPs. At this time, this would not lead to a large number of extra registrations since, as stated in the technical justification document, ‘interconnection requests for Generator Owner Facilities are still relatively rare.</p>
<p><b>Response:</b> Thank you for your comment. The scope of this SDT is addressed in the <a href="#">SAR</a>. The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT determined that it should first address “low-hanging fruit” and believes these to be sole-use Facilities (see posted examples under “Supporting Materials”) – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP). Through our deliberations, we came to the conclusion that an interconnection Facility owned or operated by a GO or</p>		



Organization	Yes or No	Question 7 Comment
<p>GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT.</p> <p>The SDT also refers the commenter to the document titled <a href="#">Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document</a>. Specifically, see the last paragraph on page 4 and first two on page 5.</p> <p>The SDT has proposed the modification of a select set of standards so that they apply to GOs and GOPs as an alternative to registering all GOs and GOPs as TOs and TOPs, a strategy that has been widely supported by the stakeholder body. The SDT does agree that upon interconnection of a third party, other standards or registrations may apply as appropriate.</p>		
<p>Southwest Power Pool Regional Entity</p>	<p>No</p>	<p>The Technical Justification document did not review the standards FERC identified in paragraphs 71 and 87 of 135 FERC ¶ 61,241 ORDER DENYING APPEALS OF ELECTRIC RELIABILITY ORGANIZATION REGISTRATION DETERMINATIONS. The SDT needs to review these standards to determine if changes are needed; otherwise, FERC will require registration of GOs and GOPs as TOs and TOPs to address reliability gaps. If the SDT determines no changes are needed to these FERC-identified standards, they should provide justification.</p>
<p><b>Response:</b> Thank you for your comment. The NERC <a href="#">Standard Processes Manual</a> does not address the issue of how to deal with FERC Orders (that don't include explicit directives) within the standards process. However, based on your and other comments, we have expanded our technical justification document (posted under "Supporting Materials") to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.</p>		
<p>Southern Company</p>	<p>No</p>	<p>We don't believe the effort realizes the goal because 1) it is inclusive of FAC-001 that does not need any modifications and 2) the effort needs to reinforce the appropriate justification not to include the additional standards FERC has identified in their Cedar Creek and Milford Orders.</p>
<p><b>Response:</b> The SDT thanks you for your comment. The SDT believes that comment (1) is a complex issue and did its best to outline how it arrived at its position in the document titled "<a href="#">Technical Justification: FAC-001-1.</a>"</p>		

Organization	Yes or No	Question 7 Comment
		<p>As for comment (2), the NERC <a href="#">Standard Processes Manual</a> does not address the issue of how to deal with FERC Orders (that don't include explicit directives) within the standards process. However, based on your and other comments, we have expanded our technical justification document (posted under "Supporting Materials") to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.</p>
<p>Western Electricity Coordinating Council</p>	<p>No</p>	<p>WECC casts an affirmative vote for the SDT proposal as a necessary but not sufficient step in addressing the GOTO matter. WECC, NERC, and the other Regions developed a subset of Standards and Requirements that were considered necessary to address potential gaps for transmission interconnection facilities and operations to be included in a proposed NERC Directive, which is expected to issue by year-end. The subset of requirements developed for the proposed NERC Directive were informed by the applicable FERC Orders. Consequently, it is important that the SDT address the comparative reliability risks between the proposed NERC Directive List and the SDT Proposal to assure that reliability gaps will not result from the SDT proposal. Please see NERC's proposed Directive for the rationale and technical justification.</p>
<p><b>Response:</b> Thank you for your comment. The NERC <a href="#">Standard Processes Manual</a> does not address the issue of how to deal with FERC Orders (that don't include explicit directives), or NERC directives, within the standards process, and until this round of comments, when NERC staff submitted comments, the SDT had no formal mandate that would have made it appropriate to consider the content of the directive you reference.</p> <p>However, based on your and other comments, we have expanded our technical justification document (posted under "Supporting Materials") to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.</p>		
<p>Florida Municipal Power Agency</p>		<p>FMPA believes that TOP-004-2 R6.2 ought to also be addressed in the standards as applicable to GOPs. The requirements reads:R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and</p>

Organization	Yes or No	Question 7 Comment
		<p>implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: R6.2. Switching transmission elements. Although planned outages are covered in other standards applicable to a GOP, switching to close / synchronize a generator back to the system is not specifically covered in the standards. Some have argued that TOP-002-2 R3 causes GOPs to coordinate its current day plans with the TOP; however, the name of the standard is “Transmission Operations Planning” and therefore implies the availability of the generator and related equipment and not necessary implies the policies and procedures for switching operations; which includes synchronization. FMPA cannot imagine a generator that would not have such switching / synchronization policies and procedures coordinated with its interconnecting TOP; as such would normally be required through a Large Generator Interconnection Agreement through a pro forma OATT; however, FMPA is not aware of any instance in the standards that covers this. As such, FMPA recommends including TOP-004-2 R6.2 as being applicable to a GOP.</p>
<p><b>Response:</b> Thank you for your comment. We don’t agree that the gap exists because TOP-002-2 R3 already requires the GO to coordinate with its host BA and TSP, who in turn are required to coordinate with their TOPs.</p>		
Manitoba Hydro		<p>If the redline changes are implemented, GOs are removed from R4, thereby removing the obligation for GOs to maintain their connection requirements. If GOs are included in FAC-001, they should be held accountable to the same level as TOs and should be required to maintain their connection requirements. Requiring a GO to maintain connection requirements would be especially beneficial to the GO themselves. In the majority of instances, any GO that is an Applicable Entity for FAC-001 would initially be inexperienced in performing interconnection studies and would benefit from regular and frequent review of their connection requirements as experience and expertise are gained.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees this is a complex issue and did its best to outline how it arrived at its position</p>		

Organization	Yes or No	Question 7 Comment
in the document titled " <a href="#">Technical Justification: FAC-001-1.</a> "		
SERC OC Standards Review Group		Please list the set of standards are you referencing.
<b>Response:</b> The SDT is referring to those standards posted for comment (FAC-001-1, FAC-003-X, FAC-003-3, and PRC-004-2.1).		
Constellation Power Source Generation, Inc.	Affirmative	Constellation appreciates and supports the work of the standard drafting team. We recognize the significant time invested by technical experts from industry to consider the appropriate application of reliability standards to address concerns raised about coverage of transmission at the generator interface. The drafting team analysis identified the standards in need of revision to appropriately address the reliability concerns raised. Please see more detailed comments submitted in the Project 2010-07 comment form submitted on November 18, 2011.
<b>Response:</b> Thank you for your comment and support.		
Infigen Energy US	Affirmative	Infigen finds the SDT supporting measures and analysis regarding FAC-003-3 to be appropriate, and believes that it is prudent for Generation Owners and Transmission Owners to manage vegetation maintenance records/inspections accordingly. We support maintaining "reasonable and appropriate" risk prevention measures to minimize encroachment that could trigger vegetation-related outages.
<b>Response:</b> Thank you for your comment and support.		
PPL EnergyPlus LLC	Affirmative	PPL Generation, LLC, on behalf of its NERC-registered subsidiaries, appreciates the effort by the Standard Development Team to address the GO-TO interface issues in a manner that enhances the reliability of the BES without adding unnecessary burden on Generators. As registered GOs/GOPs, the PPL Generation registered entities agree with the changes made by the SDT to these three standards. To the extent that GOs/GOPs are required to register as TOs/TOPs, PPL Generation would have

Organization	Yes or No	Question 7 Comment
		significant concerns with meeting the compliance requirements applicable to TOs in the standards included in the scope of this Project, as well as other TO/TOP requirements throughout other NERC standards.
<p><b>Response:</b> Thank you for your comment and support.</p>		
Puget Sound Energy, Inc.	Affirmative	The changes to this standard are minor, and seem to be centered around including "generator Interconnection facilities" to R2. This added phrase and the statement in 1.4 Data Retention "Generator Owner that owns a generation Protection System" seems to assume that the generator owner and generator interconnection facilities owner is always the same. This is not always the case, and will make this standard language confusing to prepare evidence for. A suggestion would be to revise the language to allow for a separate generator owner and generator interconnection facilities owner.
<p><b>Response:</b> Thank you for your comment. The SDT believes that the language makes clear that an entity need only be concerned with the Elements or Facilities that it owns.</p> <p>The SDT agrees with your comment regarding the language in the Data Retention section and has modified that section as follows: "The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation or generator interconnection Protection System..."</p>		
Southwest Transmission Cooperative, Inc. / ACES Power Marketing	Affirmative	We largely support the changes made by drafting team because we believe the drafting team has provided the best solution in face of a difficult problem. However, in general, we do not support registration of GOs and GOPs as TOs and TOPs or applicability of any TO/TOP requirements to the GO/GOP simply because they have a radial interconnection greater than one mile in length. While there may be some generators that own interconnecting facilities of significant length operated at a significant voltage that could impact BES reliability, we do not believe that the number of generating facilities that fit into that category is significantly large. When one considers that the majority of generators are still owned and operator by utilities that are also registered as a TO and TOP, there is only a minority subset of generators

Organization	Yes or No	Question 7 Comment
		<p>left that could be considered. NERC has the registration for this remaining set of generators and could use the data to evaluate how many of this remaining subset have interconnections owned by the generator that are substantial enough to affect reliability. It seems that NERC could determine the boundaries of this problem before registering anymore GOs and GOPs as TOs and TOPs or before applying additional requirements through this effort on the GOs and GOPs. Subjecting a GO/GOP to any TO/TOP standards requirements should require a clear demonstration of the reliability gap in each instance. Some additional changes are necessary to FAC-001.</p>
<p><b>Response:</b> Thank you for your comment and support. We are unsure as to what changes to FAC-001 you feel are necessary unless you are referring to comments stated previously.</p>		
<p>Ingleside Cogeneration LP (Occidental Chemical)</p>	<p>Yes</p>	<p>Although the SDT is nearing conclusion on the closing of reliability gaps, the unnecessary registration of GOs and GOPs as TOs and TOPs is far from resolved in our view. Ingleside Cogeneration’s concern is based upon NERC’s recent proposal to dictate an interim GO-TO interconnection solution which completely bypasses the Standards Development Process. Frankly, it seriously brings to question the nature of the consensus-driven process - which appears to be moving in a dictatorial direction.</p>
<p><b>Response:</b> Thank you for your comment and support.</p>		
<p>American Wind Energy Association</p>	<p>Yes</p>	<p>AWEA believes that the standards modifications proposed by the SDT should address any genuine reliability gap with regard to generator lead lines, rather than just perceived but unsupported threats. To that end, we support the approach that the SDT appears to be taking of modifying a limited number of applicable standards so that they apply to GO/GOP lead lines. In particular, we fully support the fact that the SDT recognizes that GO/GOPs should not automatically be required to register as TO/TOPs simply because of their ownership of generator lead lines. The SDT correctly recognizes that such registration should be done based on a case-by-case determination. As already noted, registering a GO/GOP as a TO/TOP may actually decrease reliability.</p>

Organization	Yes or No	Question 7 Comment
<b>Response:</b> Thank you for your comment and support.		
RES Americas Development	Yes	We believe that the standards modifications proposed by the SDT should address any genuine reliability gap with regard to generator lead lines, rather than just perceived but unsupported threats. To that end, we support the approach that the SDT appears to be taking of modifying a limited number of applicable standards so that they apply to GO/GOP lead lines. In particular, we fully support the fact that the SDT recognizes that GO/GOPs should not automatically be required to register as TO/TOPs simply because of their ownership of generator lead lines. The SDT correctly recognizes that such registration should be done based on a case-by-case determination. As already noted, registering a GO/GOP as a TO/TOP may actually decrease reliability.
<b>Response:</b> Thank you for your comment and support.		
Southwest Power Pool Standards Development Team	Yes	
Northeast Power Coordinating Council, Northeast Power Coordinating Council	Yes	
MRO NSRF	Yes	
SERC Planning Standards Subcommittee	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
ACES Power Marketing	Yes	

Organization	Yes or No	Question 7 Comment
Standards Collaborators		
Electric Power Supply Association	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Exelon	Yes	
Seattle City Light	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
Ameren	Yes	
American Transmission Company	Yes	
Sempra Generation	Yes	
Xcel Energy	Yes	



Organization	Yes or No	Question 7 Comment
Cowlitz County PUD	Yes	
Constellation Power Source Generation	Yes	
Puget Sound Energy, Inc.		
Compliance & Responsibility Organization		
Bonneville Power Administration		
South Carolina Electric and Gas		
Consolidated Edison Co. of NY, Inc.		
Entergy Services		
ReliabilityFirst		
Tennessee Valley Authority		

8. If you answered “yes” to Question 7, are the modifications the SDT has made in this posting the appropriate ones?

**Summary Consideration:**

The SDT thanks all stakeholders for their comments. In this section, commenters either offered their support or directed the SDT to their comments on other questions in this report.

Organization	Yes or No	Question 8 Comment
Ameren	No	Please refer to our comments in responses to #3, #4, and #5 above.
<b>Response:</b> Please see the SDT’s responses to Questions 3, 4, and 5.		
Texas Reliability Entity	No	See comment 6.
<b>Response:</b> Please see the SDT’s response to Question 6.		
Ingleside Cogeneration LP (Occidental Chemical)	No	See comments to questions 1 through 4.
<b>Response:</b> Please see the SDT’s responses to Questions 1-4.		
SERC Planning Standards Subcommittee	No	See our comments above for question # 3.
<b>Response:</b> Please see the SDT’s response to Question 3.		
South Carolina Electric and Gas	No	The modifications are appropriate with the exception noted in question #3.
<b>Response:</b> Please see the SDT’s response to Question 3.		
ACES Power Marketing	No	The modifications are largely the appropriate ones with the exceptions we noted in Q1

Organization	Yes or No	Question 8 Comment
Standards Collaborators		and Q10.
<b>Response:</b> Please see the SDT’s responses to Questions 1 and 10.		
Southwest Power Pool Standards Development Team	No	We agree that the standards being addressed are correct. See above comments. There are some issues with the determination of which facilities are deemed BES since ownership of what may be a BES facility may not always be by a Transmission Owner. All relevant standards should apply to BES facilities regardless of ownership.
<b>Response:</b> Thank you for your comment.		
PSEG	No	
<b>Response:</b>		
SERC OC Standards Review Group		See comments on Question 7. If the standards referenced in question 7 are FAC-001, FAC-003 and PRC-004, we would answer yes to this question.
<b>Response:</b> Thank you for your comment and support.		
Southern Company	Yes	“The version history table is incorrect - change version 3 to version 2.1.”
<b>Response:</b> Thank you for your comment. We have made this change.		
RES Americas Development/ American Wind Energy Association	Yes	For the most, we agree that the SDT proposal strikes a reasonable balance and provides the requisite level of clarity and certainty necessary for GO/GOPs to understand their responsibilities and compliance requirements.
<b>Response:</b> Thank you for your comment and support.		
MRO NSRF	Yes	The NSRF agrees if the drafting team incorporates as suggested improvements

Organization	Yes or No	Question 8 Comment
<b>Response:</b> Thank you for your comment and support.		
Northeast Power Coordinating Council, Northeast Power Coordinating Council	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
Electric Power Supply Association	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Exelon	Yes	
Seattle City Light	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
American Transmission	Yes	

Organization	Yes or No	Question 8 Comment
Company		
Sempra Generation	Yes	
Xcel Energy	Yes	
Cowlitz County PUD	Yes	
Constellation Power Source Generation	Yes	

**9. If you answered “no” to Question 7, what standards need to be added or removed to achieve the SDT’s goal? Please provide technical justification for your answer.**

**Summary Consideration:**

The SDT thanks all stakeholders who submitted comments. Few stakeholders suggested that standards need to be added or removed to achieve the SDT’s goal.

One commenter pointed out that PRC-005-1a required the same kind of change made in the proposed PRC-004-2.1a to ensure that generator interconnection Facility Protection Systems are included within that standard. The SDT agrees with this suggestion and has initiated a process to modify R1 and R2 in PRC-005-1a.

A few commenters returned to FAC-001-1 and stated their concern about the feasibility of adding FAC-001-1 to the applicability section of this standard. The SDT agrees with commenters that the issues surrounding the interconnection of a third party Facility to a GO’s existing Facilities are complex ones, and reminded commenters that it did its best to address these complexities in the resource document titled “[Technical Justification: FAC-001-1](#).” The SDT also points out that if the GO is part of an RTO, then the GO will be coordinating any interconnection studies either directly or indirectly with the RTO interconnection process. If the GO is not part of an RTO, then the GO will be required to follow the pro forma interconnection procedures from Order 2003. The Order 2003 procedures require the GO to coordinate any studies with an affected system which could include Facilities owned by one, or more, TO on the other side of the GO’s existing point of interconnection. The SDT acknowledges that upon interconnection of a third party, other standards or registrations may apply as appropriate.

Some commenters suggested that the SDT reexamine the standards cited in the Milford and Cedar Creek FERC orders. The SDT continues to find clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards and not requiring the GO or GOP to register as a TO or TOP. However, to address stakeholder concern, the SDT has expanded its technical justification document (posted under “Supporting Materials”) to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive.

Organization	Yes or No	Question 9 Comment
Cowlitz County PUD	No	N/A
Manitoba Hydro	No	See question 7 comments.

Organization	Yes or No	Question 9 Comment
<p><b>Response:</b> See the SDT’s response to Question 7.</p>		
<p>Southern Company</p>	<p>Yes</p>	<p>Southern does not think that the revision to FAC-001-1 is necessary. A Generator Owner (GO) cannot assess reliability impacts to the Bulk Electric System (BES) and determine acceptability without support and involvement of the applicable owner and operator of the Transmission System (i.e., the “interconnected TO” or “interconnected TP”). A generator tie-line does not equate to a Transmission System. A GO must already adhere to a TO’s Facility connection requirements whether the GO wants to connect additional facilities or a third parties’ facilities to its own interconnection Facilities. Stated another way, the GO does not need Facility Connection requirements to govern how multiple units are tied to a collector bus so why are they needed for a third party to connect to an existing tie-line? In either case it is the interconnected TO or interconnected TP that has connection requirements that must be fulfilled. The GO’s Interconnection Agreement would prohibit it from connecting additional facilities without a new application for Interconnection Service with its interconnected TO or interconnected TP. A GO should not need to develop “connection requirements” unless it is in the business of owning and operating facilities independently of its interconnected TO or interconnected TP. We do not believe a reliability gap exists in FAC-001-1 because the requestor for interconnecting another Facility to an existing generation Facility must coordinate with the applicable TO, TP, and PA in accordance with FAC-002-0 to ensure they meet all applicable facility connection and performance requirements. If and when there is an agreement in place for a third party to connect to a generator tie-line then the tie-line would become part of the integrated system and its purpose and the owner’s function would likely warrant registration as a TO/TOP and FAC-001 would then apply. The following excerpt from the 2010-07 Background Resource White Paper acknowledges that this may be necessary: “The drafting team also acknowledges that, if another party interconnects to a Facility owned by a Generator Owner, there may be the need to address MOD or TPL standards. However, the drafting team believes that this, too, is best handled through specific evaluation, perhaps accompanied by changes to the</p>

Organization	Yes or No	Question 9 Comment
		<p>compliance registry. Entities that face this kind of scenario may also meet criteria applicable to other registrations such as Transmission Service Provider or Transmission Planner.” [Arguments related to jurisdictional, interconnection policy and open access transmission tariff issues](1) Because of (a) jurisdiction under Section 215, (b) FERC’s interconnection policy, and (c) the requirements of the pro forma open access transmission tariff (OATT), a GO should not be required to comply with FAC-001-1 until that GO’s generating Facility reaches commercial operation. NERC should not make facilities subject to the mandatory reliability standards before the facilities are actually part of the BES.(a) Jurisdiction under FPA Section 215. First, it is not clear that NERC or FERC has jurisdiction under FPA Section 215 to require generation facilities that have not actually reached commercial operation to be subject to reliability standards. Section 215(a)(2) of the FPA defines the “Electric Reliability Organization” as “the organization certified by the Commission ... the purpose of which is to establish and enforce reliability standards for the bulk-power system, subject to Commission review.” Further, (a)(3) provides that “The term ‘reliability standard’ means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system. The term includes requirements for the operation of existing bulk-power system facilities ... the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system ....” Thus, under Section 215 NERC can develop reliability standards that address requirements for existing bulk-power system facilities (i.e., facilities that have reached “commercial operation”) and for the design of planned additions or modifications. It is logical to interpret the phrase “design of new facilities” as meaning that new facilities must be designed to comply with existing reliability standards. However, it is not clear that this provision should be interpreted as requiring that a generating facility that has not yet reached commercial operation should be subject to reliability standards (including audit and penalties). Therefore, the GO with the existing generation facilities should not be required to incorporate the proposed generation facility into its Facility connection requirements before the proposed generation facility is subject to NERC or FERC jurisdiction. (b) FERC’s</p>



Organization	Yes or No	Question 9 Comment
		<p>interconnection policy. In addition, the revised FAC-001 would appear to place restrictions on interconnection customers in contravention of Order Nos. 2003 and 2006 (Standard Large and Small Interconnection Procedures and Agreements). FERC was very concerned about the ability of interconnection customers to interconnect their generating facilities and gave them a fair amount of flexibility. However, this revised FAC-001 would appear to restrict some of this flexibility.(i) Order No. 2003 gives the interconnection customer the ability to terminate a proposed interconnection on ninety days notice. Therefore, the interconnection customer is not required to build the facility. However, this revised FAC-001 appears to assume that the interconnection customer does not have this flexibility. What if the interconnection customer (the GO building a new generator on its site or the third party building a new generation facility) decides to terminate the Large Generator Interconnection Agreement (LGIA) or not proceed with the generation facility? In such event, the GO may be required to revert to its previous Facility connection requirements in order to accommodate the original configuration. (ii) The LGIA permits modifications to the proposed interconnection. How would this affect the Facility connection requirements? How long would the GO have to revise its Facility connection requirements? In the event that there is a single modification, or perhaps multiple modifications, how does the GO stay in compliance with this standard? (iii) FAC-001-1, R4 provides that each GO with Facility connection requirements and each TO shall maintain Facility connection requirements and make documentation of these requirements available to users of the Transmission System upon request. However, Large Generator Interconnection Procedures (LGIP), Section 3.4 requires the posting of certain interconnection information but the identity of the interconnection customer is not to be disclosed (unless it is an Affiliate). Requirement R4 would appear to potentially require disclosure of information and (more importantly) of the interconnection customer's identity in contravention of the requirements in Order No. 2003 and the LGIP.(c) OATT requirements. The definition of “applicable Generator Owner” (Section 4.2.1) and Requirement R2 provide that the GO will have an executed Agreement to evaluate the impact of interconnecting a new facility to the GO’s</p>

Organization	Yes or No	Question 9 Comment
		<p>existing generation facility. This statement is ambiguous. This statement could be understood to mean that the GO of the existing generation Facility will enter into an Agreement with the GO proposing to interconnect and the existing GO will evaluate the impact of the proposed interconnection. However, requests to interconnect new generation are processed under an OATT. In that case, it would be the Transmission Provider (not the existing GO) that would evaluate the impact of interconnecting the new facility. Thus, the language in FAC-001-1 would need to be revised to clarify that the owner of the new facility will need to interconnect under the OATT of an appropriate Transmission Provider (i.e., the Transmission Provider to which the existing GO is interconnected, not with the existing GO). Therefore, the owner of the new facility will most likely be the entity with the executed Agreement (with the Transmission Provider). Another consideration is that the existing GO could be developing a merchant transmission line. In that case, the existing GO would need to evaluate whether it needs have its own OATT and OASIS. In that case, the new generator owner would be interconnecting to the existing GO. However, the existing GO's line would not be a generator tie-line. This issue is not clear from the draft standard. (2) The following are suggested changes to FAC-001-1. (a) We recommend the Purpose statement be revised to state, "To avoid adverse impacts on BES reliability..." (b) It is unclear in Applicability section 4.2.1 that the term "Agreement" means that the GO has an executed agreement with a TO/TSP or that the GO and the third party have an executed agreement. Without further explanation, the capitalized term "Agreement" has the effect of introducing confusion. If the SDT does not intend to propose a new addition to the NERC Glossary of Terms, it should use the lower case term, "agreement." With respect to the capitalized term, "Transmission System," the SDT should consider clarifying if it intends to propose adding this to the Glossary. (3) Effect of the proposed revisions to FAC-001-1 on FAC-002-1.(a) As drafted, there are scenarios under which a new GO may attempt to interconnect to an existing GO even though, as explained above, the interconnection should actually be done to the appropriate Transmission Provider. If the appropriate Transmission Provider is not included in the evaluation of the interconnection various types of harm may occur. In</p>

Organization	Yes or No	Question 9 Comment
		<p>such event, the TPs and PAs should be indemnified from any liability with respect to performance of the evaluations required by FAC-002. (b) FAC-001 and FAC-002 should be revised to be clear that the existing GO and any new GOs must coordinate any interconnection with the appropriate Transmission Provider, TP and PA.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees this is a complex issue and did its best to outline how it arrived at its position in the document titled "<a href="#">Technical Justification: FAC-001-1.</a>"</p> <p>The SDT points out that if the GO is part of an RTO, then the GO will be coordinating any interconnection studies either directly or indirectly with the RTO interconnection process. If the GO is not part of an RTO, then the GO will be required to follow the pro forma interconnection procedures from Order 2003. The Order 2003 procedures require the GO to coordinate any studies with an affected system which could include Facilities owned by one, or more, TO on the other side of the GO's existing point of interconnection.</p> <p>The SDT does agree that upon interconnection of a third party, other standards or registrations may apply as appropriate.</p>		
PSEG	Yes	<p>We believe that the Ad Hoc Group's suggestions regarding PRC-005-1 - Transmission and Generation Protection System Maintenance were correct and that this standard should have been modified by the SDT in a manner similar to the way the SDT modified PRC-004-2. This would require modifying R1 and R2 in PRC-005-1a (the current version) to include protection systems in the generator interconnection Facility. In addition, the SDT should evaluate modifying PER-002-0 - Operation Personnel Training. In doing so the SDT completes one of the open FERC directives in Order 693. Paragraph 1363 addresses GOP training:1363. Further, the Commission agrees with MidAmerican, SDG&amp;E and others that the experience and knowledge required by transmission operators about Bulk-Power System operations goes well beyond what is needed by generation operators; therefore, training for generator operators need not be as extensive as that required for transmission operators. Accordingly, the training requirements developed by the ERO should be tailored in their scope, content and duration so as to be appropriate to generation operations personnel and the objective of promoting system reliability. Thus, in addition to modifying the Reliability Standard to identify generator operators as applicable entities, we direct the ERO to develop specific Requirements addressing the scope,</p>

Organization	Yes or No	Question 9 Comment
		content and duration appropriate for generator operator personnel.
<p><b>Response:</b> Thank you for your comment. The SDT agrees with the comment concerning PRC-005-1a and will be initiating a process to make that change.</p> <p>With respect to PER-002-0, the SDT continues to find that there are no clear and technical reliability reasons that support adding GOP requirements to any PER standard <i>based on the fact that the GOP operates a generator interconnection Facility</i>. While the SDT does not necessarily disagree that some training requirements for GOPs may be necessary, it does not see how these changes fall within its scope.</p>		
Ingleside Cogeneration LP (Occidental Chemical)		Ingleside Cogeneration LP believes that the set of standards proposed by the SDT is technologically accurate and defensible. The open issue is if the ERO and FERC expect more standards to be included - whether based upon sound reliability principals or not.
<p><b>Response:</b> Thank you for your comment and support.</p>		
Western Electricity Coordinating Council		Please see response to question #7.
<p><b>Response:</b> See the SDT's response to Question 7.</p>		
Texas Reliability Entity		See comment 6.
<p><b>Response:</b> See the SDT's response to Question 6.</p>		
SERC OC Standards Review Group		See comments on Questions 7 & 8.
<p><b>Response:</b> See the SDT's responses to Questions 7 and 8.</p>		
Florida Municipal Power		see response to Question 7

Organization	Yes or No	Question 9 Comment
Agency		
<p><b>Response:</b> See the SDT’s response to Questions 7.</p>		
Manitoba Hydro		<p>The revision to FAC-001-1 R2 may be problematic, depending on what was intended. Under the revised requirement, the obligation to comply is dependent on the execution of an agreement to evaluate reliability impacts under FAC-002-1. However, FAC-002-1 does not clearly require the execution of an agreement by the Generator Owner. FAC-002-1 only requires the Generator Owner to “coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority”. Accordingly if a Generator Owner coordinates without executing an agreement to perform an assessment, compliance with FAC-001 R1 will not be required.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees this is a complex issue and did its best to outline how it arrived at its position in the document titled “<a href="#">Technical Justification: FAC-001-1</a>.”</p>		
Southwest Power Pool Regional Entity		<p>The SDT should consider the standards that FERC identified in 135 FERC ¶ 61,241.</p>
<p><b>Response:</b> Thank you for your comment. The NERC <a href="#">Standard Processes Manual</a> does not address the issue of how to deal with FERC Orders (that don’t include explicit directives). However, based on your and other comments, we have expanded our technical justification document (posted under “Supporting Materials”) to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.</p>		

**10. Do you have any other comments that you have not yet addressed? If yes, please explain.****Summary Consideration:**

The SDT thanks all stakeholders for their comments. In this section, many stakeholders offered supportive comments. Others offered a variety of suggestions, many of which were addressed.

One commenter suggested that the word “system” should not be capitalized in “Transmission System” in FAC-001-1 because the NERC glossary term “System” does not apply within the standard. The SDT agreed with this suggestion, and changed all references to “Transmission System” to “interconnected Transmission systems” for consistency in other parts of the standard and with FAC-002. Another commenter pointed out that “within” should be “with” in Section 4.2.1, and the SDT made this change.

A few commenters repeated their concern with the exclusion in FAC-003 for GOs with specific kinds of interconnection Facilities. For these commenters, the SDT reemphasized that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.

To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: “Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”

Some stakeholders offered comments that were outside the scope of this SDT’s work. A few offered comments on the overall strategy of the FAC-003-2 standard, and the SDT informed them that these comments should have been submitted when the Project 2007-7 Vegetation Management posted its work for comment.

One commenter suggested changes to the VSLs for R1 and R4. Because the SDT made no changes to these requirements, modifying the VSLs for these requirements is outside the scope of this team. This item will be added to the issues database.

Several stakeholders suggested the SDT review the standards cited in the draft NERC directive regarding generator interconnection leads and in the FERC orders regarding Milford and Cedar Creek. The SDT continues to find clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards and not requiring the GO or GOP to register as a TO or TOP. However, to address stakeholder concern, the SDT has expanded its

technical justification document (posted under “Supporting Materials”) to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive.

Organization	Yes or No	Question 10 Comment
Gainesville Regional Utilities	Negative	<p>1. It would seem that the impetus for FAC003 is to eliminate vegetation related outages within the rights-of-way as defined and subject to the exclusions as stated in footnote</p> <p>2. Thus the requirement is to manage the ROW to prevent vegetation related sustained outages with the measure being no outages. With grow-ins and fall-ins from within the defined ROW being controllable factors. 2. Including encroachments leaves the door open for fines to be imposed with no actual outage(s) having occurred. This may be like being found guilty of a crime that has not yet taken place.</p> <p>3. Combine vegetation related sustained outages by “grow-ins” and “blowing together of lines and vegetation located inside the ROW” as one item as they are both consequences of the growth of vegetation either vertically and horizontally.</p> <p>4. Leave vegetation related sustained outages by “fall-in” as a standalone as this will be related to structural problems occurring from a variety of sources.</p> <p>5. Combine R3 and R7 to R1 (development and implementation of a Transmission Vegetation Management Plan which shall include documented maintenance strategies or procedures or processes or specifications, delineation of an annual work plan and completion of same). Thus this would be the competency based requirements as a program without execution is meaningless.</p> <p>6. R1 and R2 become R2 and R3.</p>
<p><b>Response:</b> Thank you for your comment. This is outside the scope of the <a href="#">SAR</a> for this project. This SDT did review comments submitted as part of the <a href="#">Project 2007-07</a> effort and found that a response to this comment was provided. No change made.</p>		
Northern Indiana Public Service Co.	Negative	Ballot needs work

Organization	Yes or No	Question 10 Comment
<p><b>Response:</b> The SDT does not understand your specific concern.</p>		
<p>PSEG Energy Resources &amp; Trade LLC, PSEG Fossil LLC, Public Service Electric and Gas Co.</p>	<p>Negative</p>	<p>FAC-003-X is not applicable since FAC-003-2 was approved by the BOT on November 4, 2011</p>
<p><b>Response:</b> Thank you for your comment. You are correct that in November 2011, NERC’s Board of Trustees adopted FAC-003-2 – Transmission Vegetation Management (developed under Project 2007-07 Vegetation Management). Based on this approval, NERC staff will file FAC-003-2 with the applicable regulatory authorities. The Project 2010-07 SDT will move forward with ballots for both FAC-003-3 (proposed changes to the BOT-adopted FAC-003-2) and FAC-003-X (proposed changes to the FERC-approved FAC-003-1) with the intention of eventually only filing FAC-003-3. The SDT has elected to carry FAC-003-X through to ballot because if FAC-003-2 and FAC-003-3 are not approved by FERC, the SDT wants to be ready to file FAC-003-X to ensure that there is a functional entity responsible for managing vegetation on the piece of line commonly known as the generator interconnection Facility.</p> <p>Note that for its recirculation ballot, the SDT will be balloting <b>both</b> FAC-003-3 and FAC-003-X, but stakeholders should <b>not</b> vote as though they are choosing one or the other. As stated above, the SDT plans to present FAC-003-3 alone to NERC’s Board of Trustees, but it wants to have FAC-003-X ready to submit to the Board if, for some reason, neither FAC-003-2 nor FAC-003-3 are approved by FERC. Members of the ballot body should vote on the merits of each version of FAC-003 individually. <b>In other words, stakeholders who support adding GOs to the applicability of FAC-003 should vote in the affirmative for both FAC-003-3 and FAC-003-X.</b></p>		
<p>Hydro-Quebec TransEnergie</p>	<p>Negative</p>	<p>Hydro-Quebec TransEnergie is casting a negative vote again because our comment from the last posting was not considered in the current draft: The minimum frequency of Vegetation Inspection should be based upon an average growth rates of smaller regions than all North America. Example, above the latitude of 50 degrees North, the vegetation growth rates is limited. The Vegetation Inspection frequency in the territories located above 50 degrees of latitude must be relaxed to 3 years.</p>
<p><b>Response:</b> Thank you for your comment. This is outside the scope of the <a href="#">SAR</a> for this project. This SDT did review comments submitted as part of the <a href="#">Project 2007-07</a> effort and did not find this comment had been submitted as part of that project effort. No changes made.</p>		



Organization	Yes or No	Question 10 Comment
New Brunswick System Operator	Negative	Since NBSO voted 'affirmative' for FAC-003-3, it makes sense for us to vote 'negative' for this standard.
<p><b>Response:</b> Thank you for your comment. In November 2011, NERC’s Board of Trustees adopted FAC-003-2 – Transmission Vegetation Management (developed under Project 2007-07 Vegetation Management). Based on this approval, NERC staff will file FAC-003-2 with the applicable regulatory authorities. The Project 2010-07 SDT will move forward with ballots for both FAC-003-3 (proposed changes to the BOT-adopted FAC-003-2) and FAC-003-X (proposed changes to the FERC-approved FAC-003-1) with the intention of eventually only filing FAC-003-3. The SDT has elected to carry FAC-003-X through to ballot because if FAC-003-2 and FAC-003-3 are not approved by FERC, the SDT wants to be ready to file FAC-003-X to ensure that there is a functional entity responsible for managing vegetation on the piece of line commonly known as the generator interconnection Facility.</p> <p>Note that for its recirculation ballot, the SDT will be balloting <b>both</b> FAC-003-3 and FAC-003-X, but stakeholders should <b>not</b> vote as though they are choosing one or the other. As stated above, the SDT plans to present FAC-003-3 alone to NERC’s Board of Trustees, but it wants to have FAC-003-X ready to submit to the Board if, for some reason, neither FAC-003-2 nor FAC-003-3 are approved by FERC. Members of the ballot body should vote on the merits of each version of FAC-003 individually. <b>In other words, stakeholders who support adding GOs to the applicability of FAC-003 should vote in the affirmative for both FAC-003-3 and FAC-003-X.</b></p>		
PSEG Energy Resources & Trade LLC/ Public Service Electric and Gas Co./ PSEG Fossil LLC	Negative	The phrase “generator Facility” should be “generator Transmission Facility,” and the phrase “Transmission System” should be “Transmission system.”
<p><b>Response:</b> Thank you for your comment. We agree with your change to “Transmission system” but not to the addition of “Transmission” in the phrase “generator Facility.” The SDT does not agree with labeling a GO’s Facility as “Transmission,” in part because in some areas (like Texas), GOs, by statute, can’t own Transmission. It was also brought to the SDT’s attention that in most cases, the Facility in question is referred to as the Interconnection Facility in documents filed by the GO with FERC. Therefore, the SDT intentionally modified language so that a Facility owned by a generation entity did not contain the term “Transmission.”</p>		
SERC Reliability Corporation	Negative	There should not be a weak link under the standard. This proposed revision would create a weak-link where a portion of the otherwise covered right-of-way would be exposed.

Organization	Yes or No	Question 10 Comment
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled "<a href="#">Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface</a>," the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: "Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are..."</p>		
<p>New York State Department of Public Service/ National Association of Regulatory Utility Commissioners</p>	<p>Negative</p>	<p>Understand that there is an open issue regarding the availability of generation compliance documentation that needs to be satisfactorily addressed.</p>
<p><b>Response:</b> The SDT does not understand your specific concern.</p>		
<p>Infigen Energy US</p>	<p>Affirmative</p>	<p>Infigen supports the efforts of the SDT to ensure that Protection System Misoperations affecting the reliability of the BES are thoroughly analyzed and mitigated. Generator Owners are already analyzing Misoperations as/if they occur, and are employing Corrective Action Plans to avoid future Misoperations. We support maintaining "reasonable and appropriate" preventative measures and risk assessment tools to ensure that misoperations are evaluated and corrected expediently.</p>
<p><b>Response:</b> Thank you for your comment and support.</p>		
<p>PPL EnergyPlus LLC/PPL NERC Registered Affiliates</p>	<p>Affirmative</p>	<p>PPL Generation, LLC, on behalf of its NERC-registered subsidiaries, appreciates the effort by the Standard Development Team to address the GO-TO interface issues in a manner that enhances the reliability of the BES without adding unnecessary burden on Generators. As registered GOs/GOPs, the PPL Generation registered entities agree with the changes made by the SDT to these three standards. To the extent that GOs/GOPs are required to register as TOs/TOPs, PPL Generation would have</p>

Organization	Yes or No	Question 10 Comment
		significant concerns with meeting the compliance requirements applicable to TOs in the standards included in the scope of this Project, as well as other TO/TOP requirements throughout other NERC standards.
<b>Response:</b> Thank you for your comment and support.		
SERC Reliability Corporation	Affirmative	The Generator Owner may be required to self-certify and report periodically to the region whether they have become applicable to the standard.
<b>Response:</b> Thank you for your comment and support.		
Southwest Transmission Cooperative, Inc./ ACES Power Marketing Standards Collaborators/ ACES Power Marketing	Affirmative	The modifications to PRC-004-2.1 R2 could be interpreted as requiring the GO to analyze Protection System Misoperations on the generator interconnection Facility even if it does not own the Facility. We suggest modifying the requirement as shown below to address this issue.”The Generator Owner shall analyze Protection System Misoperations on its generator and generator interconnection Facility that it owns ...”
<b>Response:</b> Thank you for your comment. The SDT believes that the language makes clear that an entity need only be concerned with the Elements or Facilities that it owns.		
SERC Reliability Corporation	Affirmative	With the understanding the Generator Interconnection FACilities will be grouped with Transmission Protection Systems for analysis at the regional level.
<b>Response:</b> Thank you for your comment and support.		
Entergy Services		We suggest that the Vegetation Management Standards should be consistent for both the TO and GO facilities. We would also like to suggest an additional Recommendation for added clarity regarding Category 3 Outages (Off-ROW Fall-in Outages). We understand that the Category 3 Outages are not a violation of the Standard, but we feel that there should be some level of comment added within the Standard clearly stating that these Outages are “Reportable Only” during the

Organization	Yes or No	Question 10 Comment
		<p>Quarterly Outage reports to the RE's, and that there are no associated violations/sanctions for this Category Of Outage, and that an Off-ROW fall-in outage would not be considered an encroachment into the MVCD in any way. The Technical Reference Document does a good job of clearly stating this in the Introduction on Page 5 ("This standard is not intended to address outages such as those due to vegetation fall-ins or blow-ins from outside the Right-of-Way, vandalism, human activities or acts of nature.") and we feel that this should also be stated clearly in the Standard.</p>
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled "<a href="#">Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface</a>," the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: "Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are..."</p> <p>The remainder of your comment is outside the scope of this SDT.</p>		
Southern Company		<p>We agree with the 2010-17 Standard Drafting Team's conclusion to not modify other standards such as those mentioned on page 4 of the Technical Justification document. In addition, we wish to provide the following support for exclusion of these specific standards. Southern Company believes NERC's Project 2010-07 SDT must challenge making revisions to the standards included in the FERC order on Cedar Creek and Milford. (This order supports NERC's requirement for those entities to register as a TO/TOP due to their ownership of generator interconnection circuits &gt; 100kV.) We believe there are clear technical and reliability-based reasons that support not adding GO and GOP requirements to these standards and not requiring the GO or GOP to register as a TO or TOP. Furthermore, we also believe there are clear distinctions between GO/GOP responsibilities and TO/TOP responsibilities that must be</p>

Organization	Yes or No	Question 10 Comment
		<p>maintained to ensure BES reliability. Revising standards to assign TO/TOP responsibilities to a GO/GOP or requiring a GO/GOP to register as a TO/TOP because of generator interconnection circuits &gt; 100kV will reduce the clarity of these responsibilities. We have provided specific comments on each standard below:</p> <p>EOP-005-1 R1, R2, R6, R7R1 and R2 require each TOP to have and maintain a system restoration plan. R6 requires the TOP to train its operating personnel in implementing this plan. R7 requires the TOP to verify its restoration plan by actual testing or simulation. These requirements are clearly the role and responsibility of the TOP, not a GO/GOP who happens to have generator interconnection facilities in the TOP's control area. The GOP's roles and responsibilities are clearly and appropriately addressed EOP-005-2. The presence of a generator interconnection circuit &gt; 100kV that happens to be owned by the GO instead of the TOP fundamentally does not change the roles and responsibilities of the TOP or the GOP. Thus, no changes due to EOP-005 are needed.</p> <p>FAC-014-2, R2: FAC-014-2 R2 states "The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology." FAC-014-2 R2 should not be revised to include GOPs. The GO is required by FAC-008-1 R1 and FAC-009-1 (FERC approved version) and pending FAC-008-3 R3 and R6 (FAC-008-3 filed with FERC for approval) to document the Facility Ratings for a GO-owned generator interconnection circuit &gt;100kV. The established Facility Rating must respect the most limiting applicable equipment rating in the circuit and must consider operating limitations and ambient conditions. The thermal or ampere rating of this circuit would equal its ampere operating limit and should be conveyed by the GO to the GOP if they are not the same entity. The operating voltage limits for this circuit are established by the applicable TO/TOP, not the GO or GOP. Therefore, we believe adding the GO to FAC-014-2 R2 would be redundant.</p> <p>PER-003-1 R2, R2.1, R2.2PER-003-1 R2 and its sub-requirements state:"R2. Each Transmission Operator shall staff its Real-time operating positions performing</p>

Organization	Yes or No	Question 10 Comment
		<p>Transmission Operator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates (1 ) : [Risk Factor: High][Time Horizon: Real-time Operations]: R2.1. Areas of Competency R2.1.1. Transmission operations R2.1.2. Emergency preparedness and operations R2.1.3. System operations R2.1.4. Protection and control R2.1.5. Voltage and reactive R2.2. Certificates o Reliability Operator o Balancing, Interchange and Transmission Operator o Transmission Operator This requirement is specifically for TOPs. Personnel training for GOPs needs to be addressed separately and not mingled with responsibilities of the TOP. The GOPs role in supporting BES reliability needs to be clearly understood and defined prior to establishing training requirements in the standards.</p> <p>PRC-001-1, R2, R2.2, R4, R6Generator Operators (GOPs) and the scope of protection equipment for generation interconnection Facilities are already appropriately accounted for in this standard in requirement R2 and sub-requirement R2.2 The language used in requirement R2 which applies to the GOP uses the general terms “relay or equipment failures” which would include not only generator relaying, but generator interconnection relaying in the GOPs scope as well. The GOP is required to notify the TOP and Host BA in R2.1 “if a protective relay or equipment failure reduces system reliability.” Requirement R2.2 requires the affected TOP to notify its RC and affected TOPs and BAs. Thus, applying R2.2 to a GOP would be redundant to R2.1. Requirement R4 states, “Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.” A generator interconnection tie line does not constitute a ‘major tie line” or major “interconnection with neighboring GOPs, TOPs, and BAs.” Thus, R4 should not be revised to include GOPs. If a GO exists within NERC that does own such interconnection facilities, the responsibility for coordination of protection systems on such a line or interconnection should be the responsibility of the TOP in that area, not the GO/GOP. This may require formal agreements between the TO/TOP and GO/GOP, since the GO may own protection equipment on his end. The same logic applies to</p>

Organization	Yes or No	Question 10 Comment
		<p>R6. R6 states, “Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.” This is clearly the responsibility of the TOP and/or BA, not a GO/GOP who happens to have generator interconnection facilities in the area. An SPS function by definition is to maintain BES reliability. If a GO/GOP has equipment within the equipment scope of a Special Protection System (SPS), responsibility for monitoring the SPS should be conveyed in a formal agreement as appropriate.</p> <p>TOP-001-1 R1 Requirement R1 states, “Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.” This is clearly the responsibility of the TOP, not a GO/GOP who happens to have generator interconnection facilities in the TOP’s area. Thus, R1 should not be applied to a GO/GOP who owns or operates generator interconnection facilities. Furthermore, TOP-001-1 R3 (proposed to be covered in the future in the proposed IRO-001-2 R2 and R3) appropriately requires the GOP to comply with reliability directives issued by the TO “unless such actions would violate safety, equipment, regulatory or statutory requirements.” These requirements effectively give the TOP the necessary decision-making authority over operation of all generator Facilities up to the point of interconnection. They also give the GOP the necessary authority to take appropriate actions to ensure safety and protection of the GO’s equipment. Thus, no changes to TOP-001-1 are necessary.</p> <p>TOP-004-2 R6, R6.1, R6.2, R6.3, R6.4 Requirement R6 and its sub-requirements state: “R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: R6.1. Monitoring and controlling voltage levels and real and reactive power flows. R6.2. Switching transmission elements. R6.3. Planned outages of transmission elements. R6.4. Responding to IROL and SOL violations.” These are clearly</p>

Organization	Yes or No	Question 10 Comment
		<p>the responsibility of the TOP, not a GO/GOP who happens to have generator interconnection facilities in the TOP’s area. Thus, these requirements should not be applied to a GO/GOP who owns or operates generator interconnection facilities. The same logic applies here as stated above in our discussion on TOP-001-1. We believe it is inappropriate and would be adverse to BES reliability to apply these requirements to a GOP. TOP-004-2 effectively gives the TOP the necessary decision-making authority over operation of all generator Facilities up to the point of interconnection. They also give the GOP the necessary authority to take appropriate actions to ensure safety and protection of the GO’s equipment, such as opening high voltage generator output breakers when required to protect the unit. Thus, no changes to TOP-004-2 are necessary. TOP-006-2 R3 Requirement R3 states, “R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel. The intent of this requirement when applied to a GOP is already addressed in PRC-001-1 R1 which states, “Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.” Thus, no change to TOP-006-2 is necessary. ”</p>
<p><b>Response:</b> Thank you for your comment and support. We agree that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards and not requiring the GO or GOP to register as a TO or TOP. We have expanded our technical justification document (posted under “Supporting Materials”) to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive, and many of your explanations are included therein.</p>		
<p>American Wind Energy Association</p>		<p>AWEA appreciates the opportunity to submit these comments on the NERC Project 2010-07. AWEA supports the general direction indicated by both the Generator Requirements at the Transmission Interface Ad Hoc Group and the Project 2010-07 Standards Development Team. We agree with the sentiments from both groups that a GO or GOP that also owns or operates a generator lead line should not be required to register as a TO or TOP strictly because they own or operate a generator lead line. We also agree that requiring these GO/GOPs to comply with all the TO/TOP standards</p>



Organization	Yes or No	Question 10 Comment
		<p>would have little effect on or benefits to reliability of the Bulk Electric System, and could even detract from it. AWEA supports the intent and goal of the SDT to ensure that all generator-owned Facilities are appropriately covered under NERC’s Reliability Standards. We also agree with the SDT that while many GO/GOPs operate Elements and Facilities that might be considered by some entities to be Transmission, these are most often radial Facilities that are not part of the integrated grid, and as such should not be subject to the same standards applicable to TO/TOPs, who own and operate Transmission Elements and Facilities that are part of the integrated grid. Therefore, we support the SDT’s approach of identifying a very limited number of TO/TOP standards, such as FAC-001 and FAC-003, which should also apply to GO/GOP owners of generator lead lines. We would be concerned, however, if additional requirements were added beyond FAC-001, FAC-003, and PRC-004. Consideration of any additional standards with respect to generator lead lines should be done on a standard-by-standard basis, reviewing the applicability of each standard as well as the impact on the reliability of the Bulk Electric System.</p>
<p><b>Response:</b> Thank you for your comment and support.</p>		
<p>Bonneville Power Administration</p>		<p>BPA thanks you for the opportunity to comment on Project 2010-07, Generator Requirements at the Transmission Interface. BPA stands in support of the proposed revisions and has no comments or concerns at this time.</p>
<p><b>Response:</b> Thank you for your comment and support.</p>		
<p>Constellation Power Source Generation</p>		<p>Constellation appreciates and supports the work of the standard drafting team. We recognize the significant time invested by technical experts from industry to consider the appropriate application of reliability standards to address concerns raised about coverage of transmission at the generator interface. The drafting team analysis identified the standards in need of revision to appropriately address the reliability concerns raised. While the revision process focuses on specific standards, it is important to consider the reliability questions in the context of the full complement</p>

Organization	Yes or No	Question 10 Comment
		<p>of reliability standards that apply to entities. For instance, the following standards already apply to generators and relate to the reliability considerations around transmission at the generator interface:</p> <ul style="list-style-type: none"> <li>o PRC-001-1 addresses coordination of protection system components by requiring all GOs to ensure coordination of their protection system with interconnected parties. Further, FAC-002 requires that all new facilities undergo reviews by the TOP, BA, etc.</li> <li>o PRC-004-1 requires all GOs to ensure that they analyze all misoperations on their protection system which would include the protection of the tie line.</li> <li>o TOP standards applicable to GOs aid coordination between a GO and a TO with regards to the generator tie line by requiring all GOs to coordinate all maintenance and emergency outages (both forced and planned) with all applicable interconnected parties. Further, all ISO procedures require the same of GOs.</li> <li>o RC, TOP and/or BA certified operators control and are responsible for overseeing that transmission. According to the NERC functional model, a Generator Operator is defined as “operat(ing) generating unit(s) and perform(ing) the functions of supplying energy and reliability related services.” Given this limited scope, the Generator Operator (GOP) cannot be considered as operating on the same level as the Reliability Coordinator, Transmission Operator or Balancing Authority when it comes to real time information on the status of the BES. The GOP does not monitor and control the BES, rather the GOP only monitors and controls the generators that it operates and relays information to other operating entities.</li> <li>o IRO and TOP standards applicable to GOs include tie lines in their pool of resources to alleviate operational emergencies by requiring all GOs to operate as directed by their TOP, BA, or RC as directed and must render emergency assistance.</li> <li>o FAC-8 and FAC-9 manage rating methodology consistency by requiring all GOs to develop a methodology to rate all equipment, and that the RC has the authority to challenge the GO on that methodology. The onus is on the GO to either change their methodology and rating accordingly, or provide a technical justification as to why</li> </ul>

Organization	Yes or No	Question 10 Comment
		they cannot adopt the changes. Further, a generator will never be limited by its tie line, as a generator’s profits are directly tied to its output. Therefore no generator would limit its facility to the equipment that is delivering that output.
<p><b>Response:</b> Thank you for your comment and support. We agree that it is important to consider the reliability questions in the context of the full complement of reliability standards, and we have endeavored to make these broader connections clear in our revised technical justification document (posted under “Supporting Materials”). That document has been expanded to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive, and the kinds of further justifications you also provided are included therein. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.</p>		
Cowlitz County PUD		In answer to the SDT request for feedback on FERC's Order concerning Cedar Creek and Milford, the District finds no technical reason to add any of the listed standard requirements, and struggles to understand why FERC would even consider this listing as applicable.
<p><b>Response:</b> Thank you for your comment and support.</p>		
Southwest Transmission Cooperative, Inc.		In section 4.2.1 of the Applicability Section, “within” should be “with”. Because NERC’s Glossary of Terms establishes that an Agreement can be verbal and not enforceable by law, section 4.2.1 should be further modified to clarify that it is a legally enforceable and fully executed Agreement. The language in R3 in parenthesis after Generation Owner should be modified to “once required by Requirement R2”. This makes it clearer that R3 does not apply until the GO has an executed Agreement to evaluate a request by a third part to interconnect.
<p><b>Response:</b> Thank you for your comment. We agree that “within” should be “with.” The SDT chose not to adopt the second recommendation as the requirement already contains the term “executed.” The SDT also chose not to adopt the third recommendation as the requirement already contains the parenthetical (in accordance with Requirement R2) which we feel is synonymous with the comment.</p>		

Organization	Yes or No	Question 10 Comment
Manitoba Hydro		Manitoba Hydro would also like to point out that if the redline changes are implemented, it will greatly increase the complexity of coordination required under FAC-002-1 for Transmission Planners/Planning Authorities.
<p><b>Response:</b> Thank you for your comment. The SDT agrees this is a complex issue and did its best to outline how it arrived at its position in the document titled "<a href="#">Technical Justification: FAC-001-1.</a>"</p>		
Compliance & Responsibility Organization		<p>NextEra Energy, Inc. (NextEra) appreciates the work of the Project 2010-07 Generator Requirements at the Transmission Interface Standard Drafting Team (SDT) on a subject that NextEra has a significant interest in resolving. In fact, NextEra has been a member of the SDT and an active observer. Given the recent events - such as (a) the North American Electric Reliability Commission's draft interim directive; (b) the denial of the Milford and Cedar Cheek requests for reconsideration at the Federal Energy Regulatory Commission (FERC) and (c) the record in this case which, at times, suggests the SDT needs to more formally consider the Milford and Cedar Cheek Reliability Standards - NextEra requests that SDT more formally consider the merits of each Reliability Standard adopted the Milford and Cedar Cheek FERC orders and the NERC draft interim directive. Although NextEra does not condone the manner in which NERC issued the interim draft directive and stated so in its comments to NERC on the interim draft directive, NextEra's overarching objective on this issue is to bring a uniform, fair and technically supported approach that resolves the interface issue. Thus, NextEra requests that the SDT (prior to proceeding any further or any additional comments or votes on specific draft Reliability Standards) issue a technical paper that point-by-point addresses the merits of including the Reliability Standards set forth in the FERC Orders and NERC's draft interim directive, and request stakeholder, including NERC staff, comment. For example, this technical paper would likely the merits of NERC's draft interim directive not requiring NERC-certified operators (but require training of interface operators), while FERC's orders require NERC-certified operators. While NextEra does not agree five days of training is necessary for an interface operator, as the draft interim directive appears to propose, NextEra does</p>

Organization	Yes or No	Question 10 Comment
		<p>believe a technical case can be made why NERC-certification is not required, and that some degree of training related to the applicable Reliability Standards is reasonable. Similar, on FAC-003 (as well as several other Standards), the draft interim directive proposes a slightly different approach than the SDT. NextEra would rather these approaches reconciled than be in conflict, with the potential for continued conflict as the SDT's work product proceeds. Further, NextEra requests that the SDT's review the technical merits of NERC's proposed criteria to determine what generator transmission lead is required to comply with additional Reliability Standards. As noted, above, this technical paper should be posted for stakeholder, including NERC staff, comment. Accordingly, while NextEra would have preferred that NERC and the Regional Entities express there interim draft directive approach on the record in this proceeding, NextEra believes it is appropriate for the SDT to draft a comprehensive technical paper that, with an open approach, considers the inclusion of additional Reliability Standards, if appropriate, as a way of building lasting support for its approach.</p>
<p><b>Response:</b> Thank you for your comment and support. We certainly agree that is important for NERC staff and the SDT to continue to work together to try to develop a mutually agreed upon solution for dealing with this reliability gap, and to a certain extent, the SDT has tried to provide the kind of technical paper you suggest in its modified technical justification document (posted under "Supporting Materials"), which has been expanded to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. The SDT does not, at this point, plan to develop a technical paper that discusses the merits of the standards introduced by FERC and NERC, because its current focus is on filing the FAC-001-1, FAC-003-3, and PRC-004-2.1a with FERC. As it moves forward to a final solution, however, this kind of technical paper may prove useful. We appreciate the suggestion.</p>		
Dominion		No
Tennessee Valley Authority		No
Exelon		<p>PRC-004 - suggest that the Standard state that responsibility for the analysis of missoperations of protective equipment shall be the responsibility of the owner of the protective equipment.</p>

Organization	Yes or No	Question 10 Comment
<p><b>Response:</b> Thank you for your comment and support. The SDT believes that the language makes clear that an entity need only be concerned with the Elements or Facilities that it owns.</p>		
ReliabilityFirst		<p>ReliabilityFist has found a number of editorial erros for the FAC-001-1 VSLs. They include the following:1. VSL R1 - should not reference sub-requirements, should reference the sub-parts consistent with the requirement (i.e. Requirement R1, Part 1.1, 1.2 or 1.3) 2. VSL for R3 - the VSL should referenced Requirement 3, Part 3.1.1 through 3.1.16 rather than what is currently stated (Requirement R3, Part 3.1.1 R3.1.6)</p>
<p><b>Response:</b> Thank you for your comment. While we agree that the VSLs for R1 need to be updated, that change is outside the scope of this SDT because our changes are limited to those that incorporate the GO into the applicability of the requirement; the team made no changes to R1 as it only includes the TO. We have, however, made the suggested changes to the VSLs for R3.</p>		
RES Americas Development		<p>RES and AWEA appreciates the opportunity to submit these comments on the NERC Project 2010-07. We support the general direction indicated by both the Generator Requirements at the Transmission Interface Ad Hoc Group and the Project 2010-07 Standards Development Team. We agree with the sentiments from both groups that a GO or GOP that also owns or operates a generator lead line should not be required to register as a TO or TOP strictly because they own or operate a generator lead line. We also agree that requiring these GO/GOPs to comply with all the TO/TOP standards would have little effect on or benefits to reliability of the Bulk Electric System, and could even detract from it. RES and AWEA supports the intent and goal of the SDT to ensure that all generator-owned Facilities are appropriately covered under NERC’s Reliability Standards. We also agree with the SDT that while many GO/GOPs operate Elements and Facilities that might be considered by some entities to be Transmission, these are most often radial Facilities that are not part of the integrated grid, and as such should not be subject to the same standards applicable to TO/TOPs, who own and operate Transmission Elements and Facilities that are part of the integrated grid. Therefore, we support the SDT’s approach of identifying a very limited number of</p>

Organization	Yes or No	Question 10 Comment
		TO/TOP standards, such as FAC-001 and FAC-003, which should also apply to GO/GOP owners of generator lead lines. We would be concerned, however, if additional requirements were added beyond FAC-001, FAC-003, and PRC-004. Consideration of any additional standards with respect to generator lead lines should be done on a standard-by-standard basis, reviewing the applicability of each standard as well as the impact on the reliability of the Bulk Electric System.
Sempra Generation		Sempra Generation also supports the comments, being concurrently filed, of the Electric Power Supply Association (EPSA).
<b>Response:</b> Thank you for your comment and support.		
Puget Sound Energy, Inc.		The changes to this standard are minor, and seem to be centered around including "generator Interconnection facilities" to R2. This added phrase and the statement in 1.4 Data Retention "Generator Owner that owns a generation Protection System" seems to assume that the generator owner and generator interconnection facilities owner is always the same. This is not always the case, and will make this standard language confusing to prepare evidence for. A suggestion would be to revise the language to allow for a separate generator owner and generator interconnection facilities owner.
<b>Response:</b> Thank you for your comment and support. The SDT believes that the language makes clear that an entity need only be concerned with the Elements or Facilities that it owns.		
SERC Planning Standards Subcommittee/ SERC OC Standards Review Group		The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers”
<b>Response:</b> Thank you for your comment and support.		

END OF REPORT



# Consideration of Comments

## Generator Requirements at the Transmission Interface Project 2010-07: PRC-005-1.1a

The GOTO Drafting Team thanks all commenters who submitted comments on the first formal posting for PRC-005-1.1a, part of Project 2010-07—Generator Requirements at the Transmission Interface. Overwhelmingly, commenters approved the standard as written, and the team appreciates that support. These standards were posted for a 45-day public comment period from March 2, 2012 through April 16, 2012. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 19 sets of comments, including comments from approximately 65 different people from approximately 38 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

A few commenters did not support the use of the term “generator interconnection Facility” without a formal definition. Based on comments received elsewhere in this project, the SDT has avoided the creation of new NERC glossary terms, and has received significant industry support for that strategy. While it is possible that other language could have been used, the SDT believes the reference “generator interconnection Facility” is clear.

Some commenters are concerned about the changes proposed in PRC-005-1.1a given the fact that PRC-005-2 is also being revised. PRC-005-2 does not have the same issues as PRC-005-1, so no additional changes are needed to that standard to incorporate generator interconnection Facilities, but in case PRC-005-2 does not proceed to NERC’s Board of Trustees, the SDT wants to ensure that the generator interconnection Facility is covered.

Some commenters were concerned about the language in the Data Retention section of the standard. That portion of the standard was modified by NERC staff during the quality review to add boilerplate compliance language recently approved by NERC legal staff. Modifying it further is outside the scope of this SDT.

Some commenters pointed out that PRC-005-1b was approved by FERC on March 14, 2012, replacing PRC-005-1a. As noted in the text box above, going forward, all references to PRC-005-1.1a will be changed to refer to PRC-005-1.1b.

**Note:** PRC-005-1b was approved by FERC on March 14, 2012. Thus, the changes the SDT proposes will be applied to that version of the standard. To reduce confusion, the SDT’s modified standard is still referred to as PRC-005-1.1a below, but all other documents going forward will be appropriately updated to reference PRC-005-1.1b and incorporate the associated interpretation.

Some commenters stated that the addition of “generator interconnection Facility” was unnecessary because that Facility is already considered part of the Generator Owner’s assets. While the SDT believes that Generator Owners do treat the generator interconnection Facility as one of their assets, commenters in previous postings suggested that adding “generator interconnection Facility” could add clarity to the specific language in PRC-004 and PRC-005. It was pointed out to the SDT that language in the requirements of PRC-004 and PRC-005 differed from PRC-001-1, so if the requirements were applied literally, there was the possibility for the misperception that the Generator Owner was only responsible for analyzing its generator Protection Systems, exclusive of its generator interconnection Facility Protection Systems under PRC-004 and PRC-005 (whereas this interpretation wasn’t a risk under PRC-001).

PRC-001-1 used language that had more a more broad application as noted below:

- R1 – “...shall be familiar with the purpose and limitations of protection system schemes applied in its area.”
- R2 – “...shall notify reliability entities of relay or equipment failures as follows...”
- R3 “...shall coordinate new protective systems and changes as follows...”

PRC-004-2a and PRC-005-1b originally used language which could be construed as being more restrictive (as shown below):

- PRC-004-2a@R2 – “The Generator Owner shall analyze its generator Protection System Misoperations...”
- PRC-005-1b@R1 – “...each Generator Owner that owns a generation Protection System...”
- PRC-005-1b@R2 – “...each Generator Owner that owns a generation Protection System...”

The SDT agreed with the comments and modified the standards accordingly.

Other minority comments are addressed alongside their specific comments below.

The SDT considered all stakeholder comments submitted and determined that, save for the update to reference PRC-005-1.1b instead of PRC-005-1.1a, no additional changes are necessary. The standard will be posted for a recirculation ballot.

All comments submitted may be reviewed in their original format on the standard’s project page:

[http://www.nerc.com/filez/standards/Project2010-07\\_GOTO\\_Project.html](http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html)

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission,

you can contact the Vice President of Standards and Training, Herb Schrayshuen, at 404-446-2560 or at [herb.schrayshuen@nerc.net](mailto:herb.schrayshuen@nerc.net). In addition, there is a NERC Reliability Standards Appeals Process.<sup>1</sup>

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<sup>1</sup> The appeals process is in the Reliability Standards Development Procedures: <http://www.nerc.com/standards/newstandardsprocess.html>.

**Index to Questions, Comments, and Responses**

- 1. Based on stakeholder comment, the SDT inserted the phrase “or generator interconnection Facility” in Requirements R1 and R2 of PRC-005-1.1a. While there was no reliability gap in the previous version of the standard, if the Requirements were applied literally, there was the possibility for the misperception that the Generator Owner was only responsible for analyzing its generator Protection Systems, exclusive of its generator interconnection Facility Protection Systems. The clarifying changes to R1 and R2 make clear that generator interconnection Facilities are also part of Generator Owners’ responsibility in the context of this standard. Do you support the addition of the phrase “or generator interconnection Facility” to accomplish this clarification? ..... 9
- 2. Do you have any other comments that you have not yet addressed? If yes, please explain. .... 13

**The Industry Segments are:**

- 1 — Transmission Owners
- 2 — RTOs, ISOs
- 3 — Load-serving Entities
- 4 — Transmission-dependent Utilities
- 5 — Electric Generators
- 6 — Electricity Brokers, Aggregators, and Marketers
- 7 — Large Electricity End Users
- 8 — Small Electricity End Users
- 9 — Federal, State, Provincial Regulatory or other Government Entities
- 10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment										
				1	2	3	4	5	6	7	8	9	10	
1.	Group	Jesus Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X					X
<b>Additional Member Additional Organization Region Segment Selection</b>														
1.	Jose Landeros	IID	WECC	1, 3, 4, 5, 6										
2.	Epi Martinez	IID	WECC	1, 3, 4, 5, 6										
2.	Group	Guy Zito	Northeast Power Coordinating Council											
<b>Additional Member Additional Organization Region Segment Selection</b>														
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10										
2.	Greg Campoli	New York Independent System Operator	NPCC	2										
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1										
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1										
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10										

Group/Individual	Commenter	Organization	Registered Ballot Body Segment																	
			1	2	3	4	5	6	7	8	9	10								
6.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5																
7.	Kathleen Goodman	ISO - New England	NPCC	2																
8.	Chantel Haswell	FPL Group, Inc.	NPCC	5																
9.	David Kiguel	Hydro One Networks Inc.	NPCC	1																
10.	Michael R. Lombardi	Northeast Utilities	NPCC	1																
11.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9																
12.	Bruce Metruck	New York Power Authority	NPCC	6																
13.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10																
14.	Robert Pellegrini	The United Illuminating Company	NPCC	1																
15.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1																
16.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5																
17.	Brian Robinson	Utility Services	NPCC	8																
18.	Saurabh Saksena	National Grid	NPCC	1																
19.	Michael Schiavone	National Grid	NPCC	1																
20.	Wayne Sipperly	New York Power Authority	NPCC	5																
21.	Tina Teng	Independent Electricity System Operator	NPCC	2																
22.	Donald Weaver	New Brunswick System Operator	NPCC	2																
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1																
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.		3																
3.	Group	Jonathan Hayes	Southwest Power Pool Standards Development Team		X	X	X		X	X										
	<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>																
1.	Jonathan Hayes	Southwest Power Pool	SPP	NA																
2.	Robert Rhodes	Southwest Power Pool	SPP	NA																
3.	Dan Lusk	Xcel Energy	SPP	1, 3, 5, 6																
4.	Julie Lux	Westar	SPP	1, 3, 5, 6																
5.	Mahmood Safi	OPPD	MRO	1, 3, 5																
6.	Roy Boyer	Xcel Energy	SPP	1, 3, 5, 6																
7.	Mitchell Williams	Western Farmers	SPP	1, 3, 5																
8.	John Pasierb	East Texas	NA - Not Applicable	NA																
9.	David Kral	Xcel Energy	SPP	1, 3, 5, 6																
10.	Tom Hesterman	Westar	SPP	1, 3, 5, 6																

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
11.	Tiffani Lake	Westar	SPP	6, 1, 3, 5									
12.	Don Taylor	Westar	SPP	1, 3, 5, 6									
4.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				
<b>Additional Member Additional Organization Region Segment Selection</b>													
1.	Dean	Bender	WECC	1									
5.	Group	Mike Garton	Dominion- NERC Compliance Policy	X		X		X	X				
<b>Additional Member Additional Organization Region Segment Selection</b>													
1.	Connie Lowe	NERC Compliance Policy	RFC	6									
2.	Louis Slade	NERC Compliance Policy	SERC	5									
3.	Michael Crowley	Electric Transmission	SERC	1, 3									
4.	Sean Iseminger	Fossil & Hydro	SERC	6									
5.	Chip Humphrey	Fossil & Hydro	NPCC	6									
6.	Jeff Bailey	Nuclear	MRO	6									
6.	Group	Jean Nitz	ACES Power Marketing Standards Collaborators	X		X	X	X	X				
<b>Additional Member Additional Organization Region Segment Selection</b>													
1.	Mohan Sachdeva	Buckeye Power, Inc	RFC	3, 4									
2.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5									
3.	Clem Cassmeyer	Western Farmers Electric Cooperative	SPP	1, 5									
7.	Individual	Keira Kazmerski	Xcel Energy	X		X		X	X				
8.	Individual	Dan Roethemeyer	Dynegy Inc.					X					
9.	Individual	John Bee	Exelon	X		X		X	X				
10.	Individual	Art Salander	HindlePower, Inc										
11.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
12.	Individual	Martin Kaufman	ExxonMobil Research and Engineering	X				X					
13.	Individual	Michelle R D'Antuono	Ingleside Cogeneration LP					X					
14.	Individual	Dale Fredrickson	We Energies			X	X	X					
15.	Individual	Michael Falvo	Independent Electricity System Operator		X								
16.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment										
				1	2	3	4	5	6	7	8	9	10	
17.	Individual	Thad Ness	American Electric Power	X		X		X	X					
18.	Individual	Darryl Curtis	Oncor Electric Delivery Company	X										
19.	Individual	Will Smith	MRO NSRF											



1. **Based on stakeholder comment, the SDT inserted the phrase “or generator interconnection Facility” in Requirements R1 and R2 of PRC-005-1.1a. While there was no reliability gap in the previous version of the standard, if the Requirements were applied literally, there was the possibility for the misperception that the Generator Owner was only responsible for analyzing its generator Protection Systems, exclusive of its generator interconnection Facility Protection Systems. The clarifying changes to R1 and R2 make clear that generator interconnection Facilities are also part of Generator Owners’ responsibility in the context of this standard. Do you support the addition of the phrase “or generator interconnection Facility” to accomplish this clarification?**

#### **Summary Consideration:**

The SDT thanks all commenters for their feedback on the proposed changes to PRC-005-1.1a. Over 90% of commenters approved the standard as written, and the team appreciates that support.

A few commenters did not support the use of the term “generator interconnection Facility” without a formal definition. Based on comments received elsewhere in this project, the SDT has avoided the creation of new NERC glossary terms, and has received significant industry support for that strategy. While it is possible that other language could have been used, the SDT believes “generator interconnection Facility is clear, and no changes were made.

One commenter stated that the addition of “generator interconnection Facility” was unnecessary and complicates the ongoing development of PRC-005-2. The SDT believes that the clarifying language is necessary, and points out that if PRC-005-1.1a proceeds to recirculation ballot next as planned, it will actually be slightly ahead of the PRC-005-2 work, because the drafting team working on PRC-005-2 is still reviewing stakeholder comments from a successive ballot that ended March 28, 2012.

One commenter stated that the addition of “generator interconnection Facility” was unnecessary because that Facility is already considered part of the Generator Owner’s assets. While the SDT believes that Generator Owners do treat the generator interconnection Facility as one of their assets, some commenters in previous postings suggested that adding “generator interconnection Facility” could add clarity to the specific language in PRC-004 and PRC-005. The SDT agreed and incorporated that language prior to the last posting.

The SDT considered all of these comments and determined that, save for the update to reference PRC-005-1.1b instead of PRC-005-1.1a, no additional changes are necessary.

Organization	Yes or No	Question 1 Comment
Southwest Power Pool Standards Development Team	No	We would advise the Drafting team to take a look at the FERC OATT to reconcile the term “generator interconnection facility “with Tariff term for the LGIA. This should clarify the point of delineation and there should be no misconception of the language as written.
<p><b>Response:</b> Thank you for the comment. As recommended by stakeholders throughout this project, the SDT has avoided creation of new terms. No change made.</p>		
Xcel Energy	No	Xcel Energy does not believe that trying to implement a revision of PRC-005-1 at this point improves the reliability of the grid. There are better means of clarifying the perceived “misperceptions” than drafting a standard revision. This is particularly the case when PRC-005-2 is further along in the process and is also posted for industry comment and ballot. The effort of the GOTO SDT is counterproductive.
<p><b>Response:</b> Thank you for your comment. The SDT revised the standard based upon comments it received suggesting that it do so. We do agree that there may have been alternative means to address the issue, such as a request for interpretation or CAN, but given this was in the scope of the SAR, the SDT modified the standard to add the clarity recommended. If PRC-005-1.1a proceeds to recirculation ballot next as planned, it will actually be slightly ahead of the PRC-005-2 work, because the drafting team working on PRC-005-2 is still reviewing stakeholder comments from a successive ballot that ended March 28, 2012.</p>		
ExxonMobil Research and Engineering	No	The bulk electric system is contiguous. Therefore, any facility owned by the Generator Owner that is used to connect the Generator Owner’s generation facilities to the bulk electric system is already considered a bulk electric system asset and part of the Generator Owner’s generation facilities. As stated by in the question above, the addition of the term “or generator interconnection Facility” does not resolve a reliability gap or add any substance to the requirement
<p><b>Response:</b> Thank you for your comment. The SDT added the language to add clarity. As we cited above, while there was no reliability gap in the previous version of the standard, if the Requirements were applied literally, there was the possibility for the</p>		

Organization	Yes or No	Question 1 Comment
<p>misperception that the Generator Owner was only responsible for analyzing its generator Protection Systems, exclusive of its generator interconnection Facility Protection Systems. We believe that the clarifying change is useful.</p>		
<p>Kansas City Power &amp; Light (<b>Note: Comment was manually added</b>)</p>	<p>No</p>	<p>The phrase “generator interconnection” facility lacks definition making it difficult to comment on the proposed change. It is important for the standards and requirements to clearly delineate, define, or identify the facilities or operating condition subject to application of the standards and requirements.</p>
<p><b>Response:</b> Thank you for your comment. As recommended by stakeholders throughout this project, the SDT has avoided creation of new terms. No change made.</p>		
<p>Ingleside Cogeneration LP</p>	<p>Yes</p>	<p>Since PRC-005-1 already requires the Generation Owner to maintain and test all their BES Protection System components, it seems to Ingleside Cogeneration LP that the need to specify those which may trip the interconnection facility as redundant. However, we do not believe that the Standard Development Team’s modifications materially change the intent of the Standard - nor can they lead an audit team to assign a double violation for a single incidence of non-compliance.</p>
<p><b>Response:</b> Thank you for your comment. The SDT added the language to add clarity. As we cited above, while there was no reliability gap in the previous version of the standard, if the Requirements were applied literally, there was the possibility for the misperception that the Generator Owner was only responsible for analyzing its generator Protection Systems, exclusive of its generator interconnection Facility Protection Systems. We believe that the clarifying change is useful.</p>		
<p>Imperial Irrigation District (IID)</p>	<p>Yes</p>	
<p>Northeast Power Coordinating Council</p>	<p>Yes</p>	
<p>Imperial Irrigation District (IID)</p>	<p>Yes</p>	

Organization	Yes or No	Question 1 Comment
Bonneville Power Administration	Yes	
Dominion- NERC Compliance Policy	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Dynegy Inc.	Yes	
HindlePower, Inc	Yes	
Public Service Enterprise Group	Yes	
We Energies	Yes	
Independent Electricity System Operator	Yes	
Manitoba Hydro	Yes	
American Electric Power	Yes	
Oncor Electric Delivery Company	Yes	

## 2. Do you have any other comments that you have not yet addressed? If yes, please explain.

### Summary Consideration:

The SDT thanks all commenters for their feedback on the proposed changes to PRC-005-1.1a. Overwhelmingly, commenters approved of the standard as written, and the team appreciates that support.

Some commenters are concerned about the changes proposed in PRC-005-1.1a given the fact that PRC-005-2 is also being revised. PRC-005-2 does not have the same issues as PRC-005-1, so no additional changes are needed to that standard to incorporate generator interconnection Facilities, but in case PRC-005-2 does not proceed to NERC's Board of Trustees, the SDT wants to ensure that the generator interconnection Facility is covered.

Some commenters were concerned about the language in the Data Retention section of the standard. That portion of the standard was modified by NERC staff during the quality review to add boilerplate compliance language recently approved by NERC legal staff. Modifying it further is outside the scope of this SDT.

Some commenters pointed out that PRC-005-1b was approved by FERC on March 14, 2012, replacing PRC-005-1a. Going forward, all references to PRC-005-1.1a will be changed to refer to PRC-005-1.1b.

Some commenters did not support the use of the term "generator interconnection Facility" without a formal definition. Based on comments received elsewhere in this project, the SDT has avoided the creation of new NERC glossary terms, and has received significant industry support for that strategy. While it is possible that other language could have been used, the SDT believes "generator interconnection Facility" is clear, and no changes were made.

One commenter was concerned that the addressing of a literal "reliability gap" should not be considered an errata change. The SDT maintains that there is no actual reliability gap in the current standard language – just the possible perception of one. The SDT and most stakeholders still believe that the clarifying change is a useful one, but it is appropriate to classify as a minor change because it does not change the scope or intent of the associated standard. Still, the SDT agrees that the errata label is confusing, as errata changes do not require a ballot. The SDT will no longer refer to its changes as errata.

One commenter was concerned that the standard as written does not allow for alternative testing programs in cases where testing programs do not follow the ownership of the equipment. The SDT points out that an entity can enter into an agreement (including a Coordinated Functional Registration) whereby another entity is assigned responsibility for compliance with one or more requirements of one or more reliability standards without the standard itself being so modified. The SDT therefore does not agree that this standard should be explicitly modified to allow what the commenter suggests.

One commenter was concerned about the statement that “no changes” were made to the VSLs. Because the SDT has not proposed changes that affect the scope or intent of the current standard, no changes to the VSLs were necessary. The same VSLs that have been approved by FERC (which can be found in the VSL matrix posted on NERC’s website: <http://www.nerc.com/page.php?cid=2|20|288>) will remain in effect.

One commenter stated that the addition of “generator interconnection Facility” was unnecessary because that Facility is already considered part of the Generator Owner’s assets. While the SDT believes that Generator Owners do treat the generator interconnection Facility as one of their assets, some commenters in previous postings suggested that adding “generator interconnection Facility” could add clarity to the specific language in PRC-004 and PRC-005. The SDT agreed and modified the standards accordingly.

One commenter continues to find the changes proposed under Project 2010-07 to be unnecessary. As it has in previously consideration of comment reports, the SDT points out that it must act within the scope of the SAR for this project. As mandated by its SAR, the SDT has addressed standards for which there is a reliability gap or possible perception of a gap when it comes to the generator interconnection Facility, as justified in great depth in its [Technical Justification document](#).

One commenter encouraged the SDT to update the Effective Dates and Implementation Dates language to incorporate the latest NERC legal boilerplate language. That change has been made.

The SDT considered all of these comments and determined that, save for the update to reference PRC-005-1.1b instead of PRC-005-1.1a, no additional changes are necessary.

Organization	Yes or No	Question 2 Comment
Baltimore Gas & Electric Company	Abstain	Please refer to comments submitted by Exelon.
Southwest Power Pool Standards Development Team	Yes	This effort seems to be redundant due to the work going on with PRC-005-2. We do not understand why this change is being made and it wasn’t made very clear in the red line changes or in this comment form background.
<p><b>Response:</b> Thank you for your comment. The Project 2007-17 Protection System Maintenance and Testing SDT is working on comprehensive changes to PRC-005, as described in detail in the SAR posted on that projects webpage, while the Project 2010-07</p>		

Organization	Yes or No	Question 2 Comment
<p>Generator Requirements at the Transmission Interface SDT is focused on making surgical revisions to standards where there might be a reliability gap related to generator-owned Transmission Facilities. The current draft of PRC-005-2 does not have the same issues as PRC-005-1 with respect to generator-owned Facilities, so no additional changes are needed to that standard to incorporate generator interconnection Facilities, but in case PRC-005-2 does not proceed to NERC’s BOT, the Project 2010-07 SDT wants to ensure that the generator interconnection Facility is covered.</p>		
<p>Bonneville Power Administration</p>	<p>Yes</p>	<p>Regarding Section 1.3 Data Retention, BPA believes that it would be difficult for an entity to provide “other evidence” to demonstrate compliance when the data retention period is shorter than the time since the last audit. BPA requests the drafting team to offer guidance as to what "other evidence" could be provided other than what is already described in the measures. BPA believes that suggesting there is some “other evidence” without providing a description leaves the TO’s and GO’s without clear direction on how to comply with the standard. BPA suggests the data retention period should be three years or since the time the last audit occurred, whichever is longer for each TO and GO to retain evidence. Should the drafting team revise the Data Retention language to reflect BPA’s concerns, BPA would vote in favor of PRC-005-1.1a.</p>
<p><b>Response:</b> Thank you for your comment. This section was revised by NERC staff to add boilerplate compliance language recently approved by NERC legal staff. Thus, it is outside the scope of the SDT and no change was made.</p>		
<p>ACES Power Marketing Standards Collaborators</p>	<p>Yes</p>	<p>The Implementation Plan for PRC-005-1.1a should be updated to reflect the retirement of currently effective PRC-005-1b instead of PRC-005-1a. PRC-005-1b became effective on March 14, 2012 replacing PRC-005-1a.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees with the comment and has made the suggested changes.</p>		
<p>Exelon</p>	<p>Yes</p>	<p>The standard language should be clarified to allow for alternative testing programs, agreed upon by both TO and GO, in cases where testing programs do not follow ownership of the equipment for all Component Types so long as all of the protection for the generator interconnection facility is covered.</p>

Organization	Yes or No	Question 2 Comment
<p><b>Response:</b> Thank you for your comment. An entity can enter into an agreement (including a Coordinated Functional Registratyon) whereby another entity is assigned responsibility for compliance with one or more requirements of one or more reliability standards without the standard itself being so modified. The SDT therefore does not agree that this standard should be explicitly modified to allow this. No change made.</p>		
ExxonMobil Research and Engineering	Yes	<p>The SDT has utilized two terms in this round of the drafting process whose definitions are subject to interpretation. The terms ‘generating station switchyard’ and ‘generator interconnection Facility’ need to be defined to prevent inconsistent enforcement or need for the development of a Compliance Application Notice. As referenced in our comments to FAC-003-X/3, when you try to apply the term ‘generating station switchyard’ to an industrial complex that contains multiple substations between the GSU and utility interconnection facility (another substation) in order to measure the generator lead line for the 1 mile quota, there are several candidates that appear to fit the criteria.</p>
<p><b>Response:</b> Thank you for your comment. As recommended by stakeholders throughout this project, the SDT has avoided creation of new NERC glossary terms. While the SDT concedes there may be other language that could be used, the language posted has wide industry support, therefore no change will be made.</p>		
American Electric Power	Yes	<p>While we support changing the standard requirements as proposed, AEP offers the following comments and suggestions. While the implementation plans states that “there was no reliability gap in the previous version of the standard”, the previous version of the standard, if applied literally, does indeed contain a reliability gap in that it does not require Generation Owners that own a transmission Protection System to have a Protection System maintenance and testing program. It is AEP’s understanding that referring to the proposed revision as “PRC-005-1.1a” implies errata from PRC-005-1a, and the announcement refers to “very limited revisions”. If there is indeed a gap of responsibility in this standard, any changes to remediate such a gap would not be errata, regardless of the amount of proposed changes in content. As such, we recommend that the drafting team use a full revision naming</p>



Organization	Yes or No	Question 2 Comment
		<p>convention for these proposed changes, i.e. PRC-005-2. In addition, making these changes immediately effective would allow no opportunity for an entity to take the proper steps to become compliant. We believe the revision should include an implementation plan that allows industry adequate time to analyze their system and complete any additionally required maintenance and testing activities.</p>
<p><b>Response:</b> Thank you for your comment. The SDT added the language to add clarity. As we cited above, while there was no reliability gap in the previous version of the standard, if the Requirements were applied literally, there was the possibility for the misperception that the Generator Owner was only responsible for analyzing its generator Protection Systems, exclusive of its generator interconnection Facility Protection Systems. We believe that the clarifying change is a useful one, but it is appropriate to classify as a minor change because it does not change the scope or intent of the associated standard. Regarding the naming convention, the SDT was advised that the errata naming convention would be acceptable to avoid confusion with the more complete set of revisions to PRC-005 that are underway in Project 2007-17. The SDT had previously used the word “errata” to describe its changes, but agrees that the errata label is confusing, as errata changes do not require a ballot. The SDT will no longer refer to its changes as errata. No change made.</p>		
<p>Southern Illinois Power Coop., Brazos Electric Power Cooperative, Inc.</p>	<p>Affirmative</p>	<p>The Implementation Plan for PRC-005-1.1a should be updated to reflect the retirement of currently effective PRC-005-1b instead of PRC-005-1a. PRC-005-1b became effective on March 14, 2012 replacing PRC-005-1a.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees with the comment and has made the suggested changes.</p>		
<p>Pacific Gas and Electric Company</p>	<p>Affirmative</p>	<p>The data retention period identified in D1.3 cannot be shorter than the time between audits or the prior maintenance and testing interval</p>
<p><b>Response:</b> Thank you for your comment. This section was revised by NERC staff to add boilerplate compliance language recently approved by NERC legal staff. Thus, it is outside the scope of the SDT and no change was made.</p>		
<p>AEP Service Corp., AEP and AEP Marketing, American Electric Power</p>	<p>Affirmative</p>	<p>Comments are being submitted via electronic form by Thad Ness on behalf of American Electric Power</p>

Organization	Yes or No	Question 2 Comment
Great River Energy	Affirmative	Great River Energy agrees with the comments of the MRO NSRF.
Dairyland Power Coop.	Affirmative	Please see comments submitted by MRO NSRF.
Muscatine Power & Water	Affirmative	Please see comments submitted by the MRO NERC Standards Review Forum
Madison Gas and Electric Co.	Affirmative	Please see MRO NSRF comments.
Omaha Public Power District	Affirmative	Please see MRO NSRF Comments.
Brazos Electric Power Cooperative, Inc.	Affirmative	See ACES Power Marketing comments.
Occidental Chemical	Affirmative	See comments submitted by Ingleside Cogeneration LP
Central Electric Power Cooperative	Affirmative	See Matt Pacobit's comments from AECl
Southern Company Services, Inc.	Affirmative	None
Alabama Power Company	Affirmative	None
Georgia Power Company	Affirmative	None
Gulf Power Company	Affirmative	None
Mississippi Power	Affirmative	None
Southern Company Generation and Energy	Affirmative	None

Organization	Yes or No	Question 2 Comment
Marketing		
Beaches Energy Services	Affirmative	(No Comments.)
Independent Electricity System Operator		The proposed implementation plan conflicts with Ontario regulatory practice respecting the effective date of the standard. It is suggested that this conflict be removed by appending to the implementation plan wording, after “applicable regulatory approval” in the Effective Dates Section A5 of the draft standard and P. 1 of the Implementation Plan, to the following effect:”, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.”
<p><b>Response:</b> Thank you for your comment. The language you cite has been approved by NERC legal and has been updated in the Effective Dates section and in the Implementation Plan.</p>		
Sunflower Electric Power Corporation	Negative	A new term is introduced that is not a NERC defined term, the term is generator interconnection Facility. The term was inserted without comment and clearly is intended to include something that is not covered by the Standard. This new term should be removed or defined in Glossary of Terms so entities may understand just what is covered by this new term. The Implementation Plan for PRC-005-1.1a should be updated to reflect the retirement of currently effective PRC-005-1b instead of PRC-005-1a. PRC-005-1b became effective on March 14, 2012 replacing PRC-005-1a.
<p><b>Response:</b> Thank you for your comment. As recommended by stakeholders throughout this project, the SDT has avoided creation of new NERC glossary terms. The SDT purposefully did not create a new term (note that only Facility is capitalized, while generator and interconnection are not). No change made.</p>		
Seminole Electric Cooperative, Inc.	Negative	a) Section D.2 Violation Severity Levels (no changes) - The standard should stand on its own, therefore, just stating that the VSLs have "(no changes)" is incomplete and will lead to confusion. Please provide definition and clarity to this section.
<p><b>Response:</b> Thank you for your comment. The SDT has not proposed changes that affect the scope or intent of the current standard,</p>		

Organization	Yes or No	Question 2 Comment
<p>and because of that, no changes to the VSLs are necessary. The same VSLs that have been approved by FERC (which can be found in the VSL matrix posted on NERC's website: <a href="http://www.nerc.com/page.php?cid=2 20 288">http://www.nerc.com/page.php?cid=2 20 288</a>) will remain in effect. No change made.</p>		
Austin Energy, City of Austin dba Austin Energy	Negative	<p>Adding the words "generator interconnection" to the Facility description does not add clarity to the Standard. PRC-005-1 is clear as written, indicating the actual owner of a device supporting the BES is responsible for performing the actions necessary to comply with PRC-005. The term "generator interconnection" is not defined and introduces confusion, making responsibility for the application of the Requirements less clear.</p>
<p><b>Response:</b> Thank you for your comment. The SDT added the language to add clarity. As we cited above, while there was no reliability gap in the previous version of the standard, if the Requirements were applied literally, there was the possibility for the misperception that the Generator Owner was only responsible for analyzing its generator Protection Systems, exclusive of its generator interconnection Facility Protection Systems. We believe that the clarifying change is useful. No change made.</p>		
Kansas City Power & Light Co.	Negative	Concerns have been expressed in the Standard comment forms provided by NERC.
Tucson Electric Power Co.	Negative	<p>It would be difficult for an entity to provide "other evidence" to demonstrate compliance when the data retention period is shorter than the time since the last audit. Suggest that the data retention period language should be modified to "three years or since the time the last audit occurred, whichever is longer"</p>
<p><b>Response:</b> Thank you for your comment. This section was revised by NERC staff to add boilerplate compliance language recently approved by NERC legal staff. Thus, it is outside the scope of the SDT and no change was made.</p>		
Bonneville Power Administration	Negative	Please refer to BPA's comments submitted separately.
Manitoba Hydro	Negative	Please see comments submitted by Joe Petaski (Manitoba Hydro)
Xcel Energy, Inc.	Negative	Xcel Energy sees this project as counter-productive to the efforts of the Protection

Organization	Yes or No	Question 2 Comment
		System Maintenance and Testing Standard Drafting Team that currently has PRC-005-2 posted for comment and successive ballot.
<p><b>Response:</b> Thank you for your comment. PRC-005-2 does not have the same issues as PRC-005-1, so no additional changes are needed to that standard to incorporate generator interconnection Facilities, but in case PRC-005-2 does not proceed to NERC’s BOT, we want to ensure that the generator interconnection Facility is covered.</p>		
City and County of San Francisco	Negative	This revision should be used as an opportunity to clean up language relating to the data retention period for PRC-005. The following language has been suggested and appears consistent with the actual data retention period needed for all functional registrations encompassed by this Standard: "three years or since the time the last audit occurred, whichever is longer"
<p><b>Response:</b> Thank you for your comment. This section was revised by NERC staff to add boilerplate compliance language recently approved by NERC legal staff. Other changes are outside the scope of the SDT.</p>		
HindlePower, Inc	No	I beleive that the requirments as shown in 1-4a - c need to be better clarified as to the actual tasks required. There seems to be no real distinction between Verification and inspection. There is no clear reporting structure and the requirment to substitute Ohmic readings vs. discharge test is not basede on any industry reliable standards. since there is much debate in the industry as to the validity if Ohmic testing and it has not been accepted by the IEEE as an acceptbale practice I would rather see terms in line with either IEEE standard or manufacvturer's recommendations.
<p><b>Response:</b> Thank you for your comment. The SDT believes these comments may have been intended for the Project 2007-17 drafting team which is making comprehensive revisions to PRC-005-2. The comment will be forwarded to that team by NERC staff.</p>		
Manitoba Hydro	No	Manitoba Hydro does not support the changes being proposed in Project2010-07 in general. If a Generator Owner is required to register as a TO, all theRequirements applicable to a TO should apply. There is no need to changespecific Reliability

Organization	Yes or No	Question 2 Comment
		<p>Standards to allow the Generator Owner to perform only selected TO functions. For additional information, please see Manitoba Hydro's comments submitted in the comment period ending November 18, 2011. Manitoba Hydro does not believe that the SDT fully addressed our concerns in their responses to our comments in that commenting period.</p>
<p><b>Response:</b> Thank you for your comment. The SDT must act within the scope of the SAR for this project. The comments appear to indicate that the entity disagrees with the SAR although they cite the Technical Justification document. The Technical Justification document is meant to be used to show how the SDT arrived at its decisions to revise only 4 reliability standards as opposed to all that were originally included in the Ad Hoc report, or those in the cited FERC orders.</p>		
<p>MRO NSRF</p>		<p><i>Section D, Article 1.3 Data Retention</i> states that the entities retain evidence for the entire audit period since the last audit. Furthermore, in the 2<sup>nd</sup> paragraph of Article 1.3, it states that an entity “shall retain evidence of the implementation of its Protection System maintenance and testing program for three years.”</p> <p>If an entity is to prove compliance related to R2.1 and R2.2 of PRC-005-1.1a, the NSRF recommends that Evidence Retention be revised to state “the two most recent performance of each distinct maintenance activity for the Protection System Components, or all performances of each distinct maintenance activity for the Protection System Component since the previous scheduled audit date, whichever is longer.” This agrees with the current draft in progress for PRC-005-2 Section D, Compliance, Article 1.3, paragraph 4.</p> <p>The NSRF is also concerned with those testing intervals, such as 12 years, which would dictate a Registered Entity maintain 24 years of records, which is unreasonable. This should be revised to have documentation for <u>the most current</u> one testing interval, if after 06/18/07.</p> <p>The NSRF believes that “the term “generation” in R1 and R2 should be changed to “generator”. If changed, both Measures will need to be updated as well.</p>

Organization	Yes or No	Question 2 Comment
<p><b>Response:</b> Thank you for your comment. The Data Retention section was revised by NERC staff to add boilerplate compliance language approved elsewhere. Thus, it is outside the scope of the SDT and no change was made.</p> <p>In R1 and R2, the reference to “generation” was in the original standard, referring to a generation Protection System. While “generator” may work better here, it is not within the scope of the 2010-07 SDT to change language outside the surgical insertion of “generator interconnection Facility.”</p>		
Oncor Electric Delivery Company	No	
Imperial Irrigation District (IID)	No	
Northeast Power Coordinating Council	No	
Imperial Irrigation District (IID)	No	
Dominion- NERC Compliance Policy	No	
Xcel Energy	No	
Dynergy Inc.	No	
Public Service Enterprise Group	No	
Ingleside Cogeneration LP	No	

Organization	Yes or No	Question 2 Comment
We Energies	No	

END OF REPORT



# Consideration of Comments

## Generator Requirements at the Transmission Interface Project 2010-07 (FAC-003-3 and FAC-003-x)

The Generator Requirements at the Transmission Interface Drafting Team thanks all commenters who submitted comments on the second formal posting of FAC-003-3 and FAC-003-X, as part of Project 2010-07—Generator Requirements at the Transmission Interface. These standards were posted for a 30-day public comment period from March 9, 2012 through April 9, 2012. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 22 sets of comments, including comments from approximately 83 different people from approximately 76 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

The SDT considered all comments submitted and has proposed the following minor changes to FAC-003-X and FAC-003-3:

- **FAC-003-X:**
  - The Applicability section was reformatted to make it clear that the standard applies on a Facility by Facility basis (as in FAC-003-3), not simply to all generator interconnection Facilities owned by a Generator Owner with at least one qualifying generator interconnection Facility.
  - In the Purpose section, Right-of-Way was capitalized because it is an approved NERC glossary term and “North American Electric Reliability Council” was changed to “North American Electric Reliability Corporation.”
  - Regional Entity was added back to the Applicability section of the standard. Requirement R4 is assigned to the Regional Entity, and the Project 2010-07 does not have the authority, based on the scope outlined in its SAR, to modify that requirement. Thus, Regional Entity must remain in the Applicability section. In all cases, Regional Entity has been spelled out rather than referred to as “RE.”
  - New boilerplate language, recently approved by NERC legal staff, was added to the Effective Dates section of the standard and the Implementation Plan.
- **FAC-003-3:**
  - A typo was found in the Severe VSL for R2; the previous reference to “Transmission Owner” was changed to “responsible entity,” as in all other FAC-003-3 VSLs.
  - New boilerplate language, recently approved by NERC legal staff, was added to the Effective Dates section of the standard and the Implementation Plan.

Other minority comments are addressed alongside their specific comments below.

*Note that if both FAC-003-X and FAC-003-3 are approved in this recirculation ballot, only FAC-003-3 will be presented to NERC's Board of Trustees. FAC-003-X has been modified so that the generator interconnection Facility gap can be quickly addressed in the event that neither FAC-003-2 nor FAC-003-3 is approved by FERC.*

All comments submitted may be reviewed in their original format on the standard's project page:

[http://www.nerc.com/filez/standards/Project2010-07\\_GOTO\\_Project.html](http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html)

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President of Standards and Training, Herb Schrayshuen, at 404-446-2560 or at [herb.schrayshuen@nerc.net](mailto:herb.schrayshuen@nerc.net). In addition, there is a NERC Reliability Standards Appeals Process.<sup>1</sup>

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<sup>1</sup> The appeals process is in the Standard Processes Manual:  
[http://www.nerc.com/files/Appendix\\_3A\\_Standard\\_Processes\\_Manual\\_Rev%201\\_20110825.pdf](http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_Rev%201_20110825.pdf).

## Index to Questions, Comments, and Responses

1. The Project 2010-07 SDT considered Exelon’s appeal in the context of other stakeholder comments submitted in the first successive ballot between October 5 and November 18, 2011, along with advice from NERC staff. The SDT continues to believe that a reference to line of sight is clarifying and makes explicit the SDT’s implicit intent from day one. Thus, it kept the line of sight reference but made a few additional changes for formatting clarity and language consistency. The team also added a footnote to further explain what it means by “line of sight.” Do you agree with these changes? If not, please provide specific alternative language. .... 8

**The Industry Segments are:**

- 1 — Transmission Owners
- 2 — RTOs, ISOs
- 3 — Load-serving Entities
- 4 — Transmission-dependent Utilities
- 5 — Electric Generators
- 6 — Electricity Brokers, Aggregators, and Marketers
- 7 — Large Electricity End Users
- 8 — Small Electricity End Users
- 9 — Federal, State, Provincial Regulatory or other Government Entities
- 10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment											
				1	2	3	4	5	6	7	8	9	10		
1.	Group	Guy Zito	Northeast Power Coordinating Council												X
Additional Member		Additional Organization		Region		Segment Selection									
1.	Alan Adamson	New York State Reliability Council, LLC		NPCC	10										
2.	Greg Campoli	New York Independent System Operator		NPCC	2										
3.	Sylvain Clermont	Hydro-Quebec TransEnergie		NPCC	1										
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.		NPCC	1										
5.	Gerry Dunbar	Northeast Power Coordinating Council		NPCC	10										
6.	Mike Garton	Dominion Resources Services, Inc.		NPCC	5										
7.	Kathleen Goodman	ISO - New England		NPCC	2										
8.	Chantel Haswell	FPL Group, Inc.		NPCC	5										
9.	David Kiguel	Hydro One Networks Inc.		NPCC	1										
10.	Michael R. Lombardi	Northeast Utilities		NPCC	1										

Group/Individual	Commenter	Organization	Registered Ballot Body Segment											
			1	2	3	4	5	6	7	8	9	10		
11. Randy MacDonald	New Brunswick Power Transmission	NPCC 9												
12. Bruce Metruck	New York Power Authority	NPCC 6												
13. Lee Pedowicz	Northeast Power Coordinating Council	NPCC 10												
14. Robert Pellegrini	The United Illuminating Company	NPCC 1												
15. Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC 1												
16. David Ramkalawan	Ontario Power Generation, Inc.	NPCC 5												
17. Brian Robinson	Utility Services	NPCC 8												
18. Saurabh Saksena	National Grid	NPCC 1												
19. Michael Schiavone	National Grid	NPCC 1												
20. Wayne Sipperly	New York Power Authority	NPCC 5												
21. Tina Teng	Independent Electricity System Operator	NPCC 2												
22. Donald Weaver	New Brunswick System Operator	NPCC 2												
23. Ben Wu	Orange and Rockland Utilities	NPCC 1												
24. Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC 3												
2.	Group	Don Jones	Texas Reliability Entity											X
<b>Additional Member Additional Organization Region Segment Selection</b>														
1.	Curtis Crews	Texas Reliability Entity	ERCOT 10											
2.	David Penney	Texas Reliability Entity	ERCOT 10											
3.	Group	Jonathan Hayes	Southwest Power Pool Standards Development Team	X	X	X		X	X					
<b>Additional Member Additional Organization Region Segment Selection</b>														
1.	Jonathan Hayes	Southwest Power Pool	SPP NA											
2.	Robert Rhodes	Southwest Power Pool	SPP NA											
3.	Dan Lusk	Xcel Energy	SPP 1, 3, 5, 6											
4.	Julie Lux	Westar	SPP 1, 3, 5, 6											
5.	Mahmood Safi	OPPD	MRO 1, 3, 5											
6.	Roy Boyer	Xcel Energy	SPP 1, 3, 5, 6											
7.	Mitchell Williams	Western Farmers	SPP 1, 3, 5											
8.	John Pasierb	East Texas	NA - Not Applicable NA											
9.	David Kral	Xcel Energy	SPP 1, 3, 5, 6											
10.	Tom Hesterman	Westar	SPP 1, 3, 5, 6											

Group/Individual	Commenter	Organization	Registered Ballot Body Segment											
			1	2	3	4	5	6	7	8	9	10		
11. Tiffani Lake	Westar	SPP	6, 1, 3, 5											
12. Don Taylor	Westar	SPP	1, 3, 5, 6											
4. Group	Chris Higgins	Bonneville Power Administration	X		X		X	X						
<b>Additional Member Additional Organization Region Segment Selection</b>														
1. Charles	Sheppard		1											
2. Rebecca	Berdahl		3											
5. Group	Mike Garton	NERC Compliance Policy	X		X		X	X						
<b>Additional Member Additional Organization Region Segment Selection</b>														
1. Connie Lowe	NERC Compliance Policy	RFC	5, 6											
2. Michael Crowley	Electric Transmission	SERC	1, 3											
3. Jeff Bailey	Nuclear	MRO	5											
4. Sean Iseminger	F&H	SERC	5											
5. Chip Humphrey	F&H	NPCC	5											
6. Group	WILL SMITH	MRO NSRF	X	X	X	X	X	X						
<b>Additional Member Additional Organization Region Segment Selection</b>														
1. MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6											
2. CHUCK LAWRENCE	ATC	MRO	1											
3. TOM WEBB	WPS	MRO	3, 4, 5, 6											
4. JODI JENSON	WAPA	MRO	1, 6											
5. KEN GOLDSMITH	ALTW	MRO	4											
6. ALICE IRELAND	XCEL(NSP)	MRO	1, 3, 5, 6											
7. DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6											
8. ERIC RUSKAMP	LES	MRO	1, 3, 5, 6											
9. JOE DEPOORTER	MGE	MRO	3, 4, 5, 6											
10. SCOTT NICKELS	RPU	MRO	4											
11. TERRY HARBOUR	MEC	MRO	5, 6, 1, 3											
12. MARIE KNOX	MISO	MRO	2											
13. LEE KITTLESAN	OTP	MRO	1, 3, 4, 5											
14. TONY EDDLEMAN	NPPD	MRO	1, 3, 5											
15. MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6											
16. THERESA ALLARD	MPC	MRO	1, 3, 5, 6											

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
7.	Individual	Antonio Grayson	Southern Company	X		X		X	X				
8.	Individual	Brenda Frazer	Edison Mission Marketing & Trading	X				X					
9.	Individual	John Bee	Exelon	X		X		X	X				
10.	Individual	Ray Phillips	Alabama Municipal Electric Authority				X						
11.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
12.	Individual	Dan Roethemeyer	Dynegy					X					
13.	Individual	Thad Ness	American Electric Power	X		X		X	X				
14.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
15.	Individual	Dale Fredrickson	Wisconsin Electric			X	X	X					
16.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
17.	Individual	Martin Kaufman	ExxonMobil Research and Engineering	X				X					
18.	Individual	Brian Murphy	NextEra Energy, Inc.	X		X		X	X				
19.	Individual	Jean Nitz	ACES Power Marketing						X				
20.	Individual	Patrick Brown	Essential Power, LLC					X					
21.	Individual	Russell A. Noble	Cowlitz County PUD			X	X	X					
22.	Individual	Michelle R. D'Antuono	Ingleside Cogeneration LP					X					

1. **The Project 2010-07 SDT considered Exelon’s appeal in the context of other stakeholder comments submitted in the first successive ballot between October 5 and November 18, 2011, along with advice from NERC staff. The SDT continues to believe that a reference to line of sight is clarifying and makes explicit the SDT’s implicit intent from day one. Thus, it kept the line of sight reference but made a few additional changes for formatting clarity and language consistency. The team also added a footnote to further explain what it means by “line of sight.” Do you agree with these changes? If not, please provide specific alternative language.**

#### Summary Consideration:

Some commenters still do not support the qualifying language for Generator Owners (GOs) or believe that the qualifying language should be worded differently. The SDT continues to believe that the qualifying criteria for GOs are appropriate; it has explained its rationale in depth in the posted [Technical Justification Document](#). The SDT has considered all relevant stakeholder comments, including many possible language options, and is satisfied that it has determined the appropriate language to address the reliability gap.

Some commenters suggested changes to items – including the content of the VSLs and the tables attached to the standard that were outside the scope of the SDT’s work.

Some commenters raised questions about the language differences between FAC-003-X and FAC-003-3 and expressed concern that the language in FAC-003-X could lead to a “null” result whereby the qualifying language is not applied according to the SDT’s intent. The SDT sought to keep the language of 4.3.1 of FAC-003-X consistent with the language in 4.2.1 of FAC-003-X. The SDT does not believe the language in Version X can lead to a “null” result; we believe the language is as clear as possible as written, now that it has been reformatted to better match the formatting in FAC-003-3.

Some commenters questioned whether “clear line of sight” means from a fixed point or from any point along the line. The SDT clarified that it intends for the phrase “from the generating station switchyard fence to the point of interconnection” to mean that there is a clear line of sight from any point along that length of line.

One commenter questioned whether the standard applies to all generator interconnection Facilities that a GO owns if it applies to one of them. The SDT clarified that it intended for the standard to apply on a line by line basis in both FAC-003-X and FAC-003-3. To clarify this, it has reformatted the Applicability section of FAC-003-X to better match the formatting in FAC-003-3.



One commenter asked whether the standard applies to the entirety of an applicable generator interconnection Facility, or just the portion of the line greater than one mile. The SDT clarified that if a GO owns an applicable line, the GO is responsible for the entirety of that line. The SDT believes that this is clear in the standards as written.

One commenter expressed concern that the implementation timeframe is too long. The SDT reminded the commenter that the time frame was based on previous stakeholder comments and the fact that the implementation of Version 0 standards – the transition into which marked the time that TOs needed to begin applying FAC-003 on a mandatory basis – occurred over more than two years. It is therefore reasonable to assume that GOs, having never had to comply with a vegetation management standard, be afforded adequate time to do so.

One commenter continues to find the changes proposed under Project 2010-07 to be unnecessary. As it has in previous consideration of comment reports, the SDT points out that it must act within the scope of the SAR for this project. As mandated by its SAR, the SDT has addressed standards for which there is a reliability gap or possible perception of a gap when it comes to the generator interconnection Facility, as justified in great depth in its [Technical Justification document](#).

The SDT considered all comments received and decided to address typos, improve the formatting of the Applicability section of FAC-003-X, and update the boilerplate language in the Effective Dates sections of the standards and their implementations plans. The SDT has proposed no substantive changes to the standards.

Organization	Yes or No	Question 1 Comment
Ameren Services	Negative	<p>(a) There is no technical basis for the one mile length exemption. In fact, one could argue that a very short line, 300 feet in length, that experienced a fault from a tree at "the end of the circuit", i.e near the switchyard fence, would have much more of an impact on the BES because the fault would be limited by much less impedance.</p> <p>(b) For the GO that owns several lead lines but only one of the lines is greater than one mile in length, does this standard apply to all the lead lines he owns? A response can be affirmative with the current language of the section 4.2.1. If this is not the intent, it should be clarified.</p> <p>(c) It is also unclear in this version if a GO that owned one line that was 1.2 miles in length would have to comply for the entire length of said line, or just 0.2 miles of said line. If the GO is responsible for 1.2 miles, then that</p>

Organization	Yes or No	Question 1 Comment
		<p>argues that the first mile is important and consequently there is no basis for ignoring the first mile on other lines. If the GO is only responsible for 0.2 miles, what is the technical basis to ignore a mile? And would it be the first mile from the switchyard that is ignored, or is the middle mile, or the last mile where it connects to the TO? Or could the GO decide? Or could the GO pick sections of the line that amount to a mile that they can ignore? This seems like something that should be addressed for compliance.</p> <p>(d) The 2 year compliance time line is far too long. There is significant industry evidence that was developed in the drafting of Version 2 that supports a one year compliance time-line for new lines. This is evidenced in Version 2. Thus there is no basis for the 2 years</p>
<p><b>Response: Thank you for your comment. The SDT continues to believe that the qualifying criteria for GOs are appropriate; it has explained its rationale in depth in the posted <a href="#">Technical Justification Document</a>. The SDT has considered all relevant stakeholder comments and is satisfied that it has determined the appropriate language to address the reliability gap.</b></p> <p><b>The SDT intended for the standard to apply on a line by line basis in both FAC-003-X and FAC-003-3. To clarify this, it has reformatted the Applicability section of FAC-003-X to better match the formatting in FAC-003-3.</b></p> <p><b>If a GO owns an applicable line, the GO is responsible for the entirety of that line. The SDT believes that this is clear in the standards as written.</b></p> <p><b>With respect to the Implementation Plan, the SDT reminds Ameren that the time frame was based on previous stakeholder comments and the fact that the implementation of Version 0 standards – the transition into which marked the time that TOs needed to begin applying FAC-003 on a mandatory basis – occurred over more than two years. It is therefore reasonable to assume that GOs, having never had to comply with a vegetation management standard, be afforded adequate time to do so.</b></p>		
BC Hydro and Power Authority	Negative	<p>“BC Hydro agrees with the revisions to FAC-003-3 and would vote Affirmative except for the following two items.</p> <p>One: The FAC-003-2 adopted by the NERC Board of Trustees had a significant change to what was voted on in Draft 6 in the Table of Compliance Elements (R1 and R2). In the table on Page 13 of the version</p>

Organization	Yes or No	Question 1 Comment
		<p>adopted by the NERC Board of Trustees on November 3, 2011, the VSLs were changed and the staff proposed violation severity levels were adopted and the review team recommendations were rejected. Therefore, there is no Low or Moderate VSLs for these two violations only High and Severe. This was rejected earlier by a number of utilities including BC Hydro and was not in the version 6 draft that was voted for on the last ballot. This change as adopted is a concern as it expects a level of program perfection that seems unrealistic. It is also at odds with the Rationale for R1 and R2 outlined on Page 32 of the standard “Guideline and Technical Basis” section which gives an explanation for the increasing levels of violation severity. Program failures that were deemed to be “unusual conditions in an otherwise sound program” or “not adequately addressed by the program” formerly rated as Lower or Moderate VSL are now rated as High. It also extends the severity of the violation beyond what is currently in FAC-003-1 although the levels of non-compliance are not strictly comparable between versions. This change is carried on in the Draft FAC-003-3.</p> <p>Two: Table 2 (pg. 30 and 31 of FAC-003-3 Draft 3) for Minimum Vegetation Clearance Distances for AC Voltages now includes clearance calculations for 287 kV which is good and was something BC Hydro asked for. However, the calculations don’t seem to be correct as the limits are higher than for 345kV. BC Hydro recommends either providing an explanation as to why these limits seem to be out of sequence to increasing voltage or recalculate them.”</p>
<p><b>Response:</b> Thank you for your comment. The SDT's SAR is very limited in scope (determining which additional standards should apply to a GO/GOP). The SDT made no changes to the VSLs and simply included the FAC-003-2 VSLs that were approved by NERC’s BOT, as those are the VSLs that will be filed with FERC. Similarly, the SDT made no changes to Table 2, as that would also have been outside its scope; the SDT exclusively made changes that would add GOs or GOPs to standard requirements or applicability sections, and changes that would bring the standard up to date according to current NERC templates. No change made.</p>		

Organization	Yes or No	Question 1 Comment
ComEd	Negative	Please refer to Exelon's comments submitted in the electronic comment form
PECO Energy	Negative	Please refer to Exelon's comments submitted in the electronic comment form
Gulf Power Company	Negative	See comments submitted via the electronic comments form by Antonio Grayson.
Mississippi Power	Negative	See comments submitted via the electronic comments form by Antonio Grayson.
Alabama Power Company	Negative	See comments submitted via the electronic comments form by Antonio Grayson.
Utility Services, Inc.	Negative	The applicability language under Version X is not the same as the language in Version 3. We do not believe that applicability language in Version X can ever result in a “True” logical outcome whereas the language in Version 3 can. We understand the intent; however, applying the specific language using the logical "AND" in the applicability portion of the standard will always come out with a null result. We suggest the SDT adopt the applicability language in Version 3 in Version X.
<p><b>Response: Thank you for your comment. The SDT sought to keep the language of 4.3.1 of FAC-003-X consistent with the language in 4.2.1 of FAC-003-X. The SDT does not believe the language in Version X can lead to a “null” result; we believe the language is as clear as possible as written now that it has been reformatted to better match the formatting in FAC-003-3. No change made.</b></p>		
Xcel Energy, Inc.	Negative	This project is counter-productive to the efforts of the Protection System Maintenance and Testing Standard Drafting Team that concurrently has

Organization	Yes or No	Question 1 Comment
		PRC-005-2 posted for comment and successive ballot.
<p><b>Response: Thank you for your comment. The SDT believes this comment was submitted in response to PRC-005 and will address it with comments received under that standard.</b></p>		
SERC Reliability Corporation	Negative	<p>We have concern that if this passes there will be BES Elements that will not be covered by the vegetation management standard that are currently included in the standards and that this determination is based solely on ownership and not risk to reliability. SERC supports BES reliability and as vegetation management was identified as a significant contributor to the 2003 Blackout we do not support a revision that would create a gap in the results-based, defense-in-depth approach that has been determined to be necessary for the reliable operation of the interconnected transmission network.</p>
<p><b>Response: Thank you for your comment. GOs are not currently covered under any vegetation management requirements, so the SDT does not understand the comment about removing coverage for BES Elements “that are currently included in standards.” The applicability to TOs, the entity currently subject to vegetation management requirements, is not changing. The SDT recognizes that in many cases, generation Facilities are (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale for exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. No stakeholder has commented that there are similarly situated transmission facilities.</b></p>		
Southern Company	No	<p>The requirement as worded implies or could be interpreted to mean one's line of site would have to originate at the generating station switchyard fence. The "clear line of site" should also include that from a roadway that travels in proximity to the line. Such a roadway's purpose would likely include access to the line for inspections, maintenance, travel from the plant to the transmission substation, etc. Since the terrain between the generating station switchyard fence and the point of interconnection could obscure the view from the fence, the clear line of site from such a roadway</p>

Organization	Yes or No	Question 1 Comment
		<p>should be allowed. The requirement should be revised to read, "...or (2) does not have clear line of sight<sup>1</sup> from the generating station switchyard fence or a roadway to the point of interconnection with a Transmission Owner's Facility."</p>
<p><b>Response: Thank you for your comment. The SDT appreciates this discussion, and had many similar discussions during its own deliberations. The SDT intends for the phrase "from the generating station switchyard fence to the point of interconnection" to mean that there is a clear line of sight from any point along that length of line. The SDT has considered all relevant stakeholder comments and is satisfied that it has determined the appropriate language to address the reliability gap. No change made.</b></p>		
<p>Southwest Power Pool Standards Development Team</p>	<p>No</p>	<p>Clear line of sight" means the distance that can be seen by the average person "standing at ground level "without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.</p>
<p><b>Response: Thank you for your comment. The SDT has considered all relevant stakeholder comments and is satisfied that we have determined the appropriate language to address the reliability gap.</b></p>		
<p>Cowlitz County PUD</p>	<p>No</p>	<p>Cowlitz must agree with Exelon's position inasmuch that the vantage point must be related to the generating station switchyard maintenance or the operation and maintenance of the generation plant itself, and afford a clear perspective of vegetation proximity. Cowlitz also agrees with the SDT's line of sight clarifying verbiage. However, restricting the vantage point to the generating station switchyard fence does not encompass the spirit of the exclusion. A short one-mile transmission interconnection line - from the generating station switchyard to the interconnection point - that is frequently viewed during the operation and maintenance of the generation plant itself should be the crux of the exemption.</p> <p>The exact location, i.e., the generating station switchyard fence, of the vantage point is not the make or break of whether the interconnection line will be routinely inspected by default. As an example, consider a hydro project where the generating station switchyard may be located near the</p>

Organization	Yes or No	Question 1 Comment
		<p>tailrace inside a canyon. From the fence line of this particular switchyard, only the interconnection line traversing up the canyon wall is visible. However, topside of the dam where maintenance and operational personnel must daily traverse under the interconnection line to access the powerhouse and switchyard may afford a clear view of both the generating station switchyard below and the interconnection station which includes the whole interconnecting line in-between.</p> <p>Further, if parts of the interconnecting line is viewable in two or even three vantage points beneath the interconnection line during the normal transit to and from the generating station switchyard, the sum of which comprises the whole line, can this not also meet the spirit of the exclusion?</p> <p>Conversely, Cowlitz does not hold that any vantage point should be acceptable. Any vantage point that must require special effort to access no matter the ease is not acceptable. Also, a perpendicular view of a line (not under or near) complicates perception of the proximity of vegetation to a line. Views parallel down the right-of-way maximizes perception of vegetation proximity.</p> <p>Further, a long line that is fully viewable during transit to and from the generation plant increases the chance of hidden vegetation encroachment. Cowlitz strongly opposes any trivializing of reliability compliance collateral damage. Forcing compliance activities with no reliability return must be avoided wherever possible. As a stakeholder with limited time to invest reviewing all the comments submitted, Cowlitz offers an apology to Exelon for missing their initial comment. Cowlitz commends Exelon’s persistence in this matter.</p> <p>***Suggested language: ...or (2) do not have a clear line of sight (leave the footnote in place) up and/or down from a single vantage point within the transmission right-of-way where both the origin at the generating station switchyard and the termination interconnection point with the Transmission</p>

Organization	Yes or No	Question 1 Comment
		Owner’s Facility can be seen, and where operations or maintenance personnel frequent on foot during normal generation plant or generating station switchyard access is made...
<p>Response: Thank you for your comment. The SDT appreciates this discussion, and had many similar discussions during its own deliberations. The SDT intends for the phrase “from the generating station switchyard fence to the point of interconnection” to mean that there is a clear line of sight from any point along that length of line. We do not believe that adding the language you suggest necessarily adds clarity, and we’re concerned that it may raise additional questions. In sum, the SDT has considered all relevant stakeholder comments and is satisfied that we have determined the appropriate language to address the reliability gap. No change made.</p>		
Exelon	No	<p>Exelon disagrees with the current proposed draft of FAC-003-3/X because the reference to a “clear line of sight from the generating station switchyard fence to the point of interconnection” does not clarify the Standard and is unsupported by any technical basis. Furthermore, the definition of “clear line of sight” added by the SDT does not address or remedy the substantive concerns raised in Exelon’s appeal.</p> <p>Exelon reiterates that the SDT should base the applicability of the Standard on the length of the transmission line, a measurable component of the bulk electric system, and remove all references to a “clear line of sight.” This approach is consistent with previous draft versions of FAC-003 proposed by the SDT and the Ad Hoc Group and the recent recommendation of the NERC Vice President of Standards and Training in response to Exelon’s appeal.</p> <p>Alternatively, if the “clear line of sight” verbiage remains, the Standards should be clarified to remove the requirement that the line of sight be established from “the generating station switchyard fence to the point of interconnection” and to add a requirement or clarify that “clear line of sight” for lines of one mile or less can include observation of the length of the transmission lines from various vantage points within the owner controlled property. The SDT states in the “Background” section of the</p>



Organization	Yes or No	Question 1 Comment
		<p>Unofficial Comment Form that “a reference to the line of sight is clarifying and makes explicit the SDT’s implicit intent from day one.”</p> <p>Yet, the SDT offers no support for its “implicit intent from day one,” and a review of the history for these Standards certainly does not support an “implicit intent from day one” to require a clear line of sight from a fixed location, let alone the generating station switchyard fence, to the point of interconnection. The Technical Justification document posted in September 2011 (p. 3) refers to the Ad Hoc Group’s original thought to exclude from the Standards any transmission lines that were “less than two spans [long] (generally one half mile from the generator property line).” In agreeing “with that intended exclusion in principle,” the SDT explained (p. 3) that, “[a]fter reviewing formal comments, the SDT agreed to revise the exclusion so that it applies to a Facility [transmission line] if its length is ‘one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard’ to approximate line of sign [sic] from a fixed point,” (the fixed point being the fenced area of the generating station switchyard). From the start, the Ad Hoc Group and SDT focused on the length of the transmission line (either a half mile as proposed by the Ad Hoc Group or a mile as proposed by the SDT) as the proxy for line of sight, the presumption being that up to a certain distance, the overhead line is in the line of sight at various locations throughout the Generator Owner’s property and reasonably subject to being managed through normal day-to-day plant activities.</p> <p>The SDT has not, until the most recent iteration of the Standards, focused on requiring a “clear line of sight from the generating station switchyard fence to the point of interconnection.” As support for adding the “clear line of sight” requirement to the FAC-003-3/X Standards in December 2011, the SDT noted as follows: “We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and</p>

Organization	Yes or No	Question 1 Comment
		<p>any discretion on the part of a Generator Owner or an auditor.” With the addition of an explicit line of sight reference here, the SDT believes it has clarified its original intent. (Side bar comments to FAC-003-3, Section 4.3.1 (December 1, 2011); FAC-003-X, Section 4.3.1 (December 1, 2011)).</p> <p>This explanation does nothing more than (1) reiterate the point the SDT has maintained throughout the entire drafting process, namely that “the one mile length” of a transmission line “is a reasonable approximation of line of sight,” and (2) explain that the SDT included a “fixed starting point” (the fenced area of the generation station switchyard) from which to measure the length of the transmission line to address stakeholder concerns about excessive Generator Owner discretion with respect to the location from which to take a measurement and inconsistent application of the Standards.</p> <p>Again, the SDT’s “intent” (implicit or otherwise) “from day one” has nothing to do with establishing a “clear line of sight from the generating switchyard fence to the point of interconnection.” In addition, requiring a “clear line of sight from the generating station switchyard fence to the point of interconnection” is technically unsupported. The SDT just added the requirement for a “clear line of sight to the point of interconnection” language without considering the implications of why such a change was required or reasonable. While a specific fixed starting point (the generating station switchyard fence) and end point (the point of interconnection) may make sense for establishing a starting and ending point from which to measure the length of the transmission line (the one-mile limitation), it does not make sense when considering a clear line of sight, especially in light of stakeholder comments and the SDT’s repeated acknowledgment that in many cases, generation Facilities are either (1) staffed and the overhead portion is within the line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that</p>

Organization	Yes or No	Question 1 Comment
		<p>these qualifiers represent a reasonable and appropriate risk prevention approach.(Consideration of Comments, Generator Requirements at the Transmission Interface, Project 2010-07 (for November 9, 2011 successive ballot), p. 1; Technical Justification Resource Document (posted March 2012), p. 3.)</p> <p>By inserting the “clear line of sight” requirement now without modifying the fixed starting point, the SDT completely ignores its unequivocal acknowledgment that generation Facilities are unique in the sense that personnel can see the line from various locations within the owner controlled area and many generation Facilities are over paved surfaces. The absence of a technical justification for imposing a “clear line of sight” is illustrated by the following example.</p> <p>A Generator Owner transmission line leaving the generating station could take a “dog leg” turn (the line turns at one of the towers). Standing at the tower in this example, an individual would have a clear line of sight of the entire line to either end of the short-distance line (to the end leaving the station and to the end terminating at the point of interconnection). Since the generating Facility is within the Generator Owner’s property line or controlled area and consistently staffed by personnel who patrol the owner controlled area, the line can be observed and maintained by staff in the same manner as any other short distance line with a “clear” line of sight from the “generating station switchyard fence to the point of interconnection.” Moreover, to the extent a portion or the entire length of the line travels over paved surfaces or structures, any barriers or obstacles to a clear line of sight will not be caused by vegetation, as discussed in FAC-003-3/X but, rather, by equipment, components, or structures. Clearance between generator lines and structures is already covered in other NERC Standards. For those lines that do travel over areas of vegetation, the regular personnel monitoring and surveillance of the areas over which the lines travel provides reasonable assurance of protection from vegetation</p>

Organization	Yes or No	Question 1 Comment
		<p>related events.</p> <p>Rather than clarifying the Standards, the SDT has introduced more ambiguity into the Standards. The addition of the “generating station switchyard fence” as the point of reference for a clear line of sight adds more confusion than it solves by introducing a variable that will be left to the discretion of generator owner and an auditor. What is the definition of a “generating station switchyard fence?” As Exelon noted in its Appeal and at least one other Registered Entity noted in its Comments for the first successive ballot (Consideration of Comments posted March 2012, p. 38), some generation facilities do not have generating switchyards or generating switchyard fences. A requirement that there be a clear line of sight from the “generating switchyard fence” is meaningless in cases where no such switchyard or fence exists. Is it the fence surrounding the generating unit or is it meant to refer to the fence surrounding the Transmission Owner’s associated switchyard and relay house? What if there are multiple physical fence lines between the generating unit and the point of interconnection? In addition, by introducing a point of reference that is not a physical component or measurable reference of the bulk electric system, what precludes the Generator Owner from arbitrarily moving the fence line to avoid applicability? Also lacking in clarity is the addition of a footnote defining “clear line of sight” to mean “the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.” Generation Owners will be left to determine what constitutes an “average person,” a “clear day,” and “special instrumentation.”</p> <p>For all these reasons, Exelon requests that the SDT base the applicability of the Standard on the length of the transmission line, a measurable component of the bulk electric system, and remove all references to a “clear line of sight.” Alternatively, if the “clear line of sight” verbiage remains, the Standards should be clarified to remove the requirement that</p>

Organization	Yes or No	Question 1 Comment
		<p>the line of sight be established from “the generating station switchyard fence to the point of interconnection” and to add a requirement or clarify that “clear line of sight” for lines of one mile or less can include observation of the length of the transmission lines from various vantage points within the owner controlled property.</p>
<p><b>Response: Thank you for your comment. The SDT appreciates this discussion, and had many similar discussions during its own deliberations. We maintain that the addition of the reference to “clear line of sight” is clarifying and helps support the rationale behind the one mile exemption. A line less than one mile that passes through a dense grove should not be exempt from this standard, but a line that is less than one mile and is either (1) staffed and within line of sight or (2) over a paved surface <i>should</i> be exempt.</b></p> <p><b>The SDT intends for the phrase “from the generating station switchyard fence to the point of interconnection” to mean that there is a clear line of sight from any point along that length of line. We do not believe that adding a reference to a fixed vantage point necessarily adds clarity, and we’re concerned that it may raise additional questions. In sum, the SDT has considered all relevant stakeholder comments and is satisfied that we have determined the appropriate language to address the reliability gap. No change made.</b></p>		
Texas Reliability Entity	No	<p>In FAC-003-X:</p> <ol style="list-style-type: none"> <li>1. We appreciate that you took Regional Entity out of the Applicability section, but there is still a Requirement (R4) that applies to the Regional Entity. Is that Requirement intended to be enforceable against the Regional Entities? We suggest removing Requirement R4.</li> <li>2. In Part D.1.1, only the Regional Entity should be listed as Compliance Monitor, since the Regional Entity has been removed as an Applicable entity.</li> <li>3. In the Purpose section, update the reference to NERC (use “Corporation” instead of “Council”), and capitalize “Rights-of-Way” since it is a defined term.</li> </ol>

Organization	Yes or No	Question 1 Comment
		<p>4. We suggest that you spell out “Regional Entity” in Applicability part 4.2.1.</p> <p>5. In the implementation plan, the reference to “R3” should be corrected to “R1” in the following sentence: “In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.”</p> <p>In FAC-003-3:</p> <p>6. There is no Compliance Monitor listed on page 17. At least the Regional Entity should be listed here.</p> <p>7. In the Severe VSL for R2, replace “Transmission Owner” with “responsible entity.”</p> <p>8. In the Severe VSL for R1 and R2, remove “active transmission line” before “ROW.” That phrase is confusing in the VSLs because it does not appear in the requirements, and it is not clear whether it is intended to change the requirements.</p> <p>9. In Table 2 (Alternating Current - meters AND Direct Current) the footnote references are wrong. We think they should be 9 and 10, rather than 7 and 8.</p> <p>10. In Table 2 (Direct Current), the column headings are wrong. Only the first column heading should refer to voltage. The rest should refer to MVCD.</p>
<p><b>Response: Thank you for your comment.</b></p> <ol style="list-style-type: none"> <li><b>1. The SDT has reverted back to the original Applicability (which included the Regional Entity) because deleting a requirement is outside the scope of this drafting team.</b></li> <li><b>2. Because the Regional Entity was returned to the Applicability section, the second bullet in section D1.1 must remain.</b></li> <li><b>3. Changes made.</b></li> <li><b>4. Regional Entity has been spelled out in all cases.</b></li> </ol>		

Organization	Yes or No	Question 1 Comment
<p>5. Change made.            6. The Compliance Enforcement Authority section has been updated as suggested.            7. Change made.            8. Modifying the VSLs beyond the change from “Transmission Owner” to “responsible entity” is not within the scope of the SDT, and these VSLs have already been approved by NERC’s BOT.            9. These are 9 and 10 in both the clean version and the redline version.            10. The Project 2010-07 SDT did not modify this table.</p>		
Manitoba Hydro	No	<p>Manitoba Hydro does not support the changes being proposed in Project 2010-07. If a Generator Owner is required to register as a TO, all the Requirements applicable to a TO should apply. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. For additional information, please see Manitoba Hydro's comments submitted in the comment period ending November 18, 2011. Manitoba Hydro does not believe that the SDT fully addressed our concerns in their responses to our comments in that commenting period.</p>
<p><b>Response:</b> Thank you for your comment. Under the SDT’s changes, GOs are not going to be required to register as TOs, so this comment does not apply.</p> <p>To reiterate our comments in previous comment reports, the intent of the SDT’s SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT determined that it should first address “low-hanging fruit” and believes these to be sole-use Facilities (see posted examples under “Supporting Materials” posted alongside the December ballot) – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP). Through our deliberations, we came to the conclusion that an interconnection Facility owned or operated by a GO or GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT.</p> <p>The SDT also refers the commenter to the document titled <a href="#">Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document</a>.</p>		
Liberty Electric Power LLC	No	The "line of sight" should be removed. It opens up the entity to a finding of

Organization	Yes or No	Question 1 Comment
		non-compliance if a temporary blockage of line of sight should occur.
<p>Response: Thank you for your comment. We maintain that the addition of the reference to “clear line of sight” is clarifying and helps support the rationale behind the one mile exemption. A line less than one mile that passes through a dense grove should not be exempt from this standard, but a line that is less than one mile and is either (1) staffed and within line of sight or (2) over a paved surface <i>should</i> be exempt. Nothing in the proposed standard prohibits an entity from self-imposing the requirements contained within in order to mitigate any perceived risk of potential non-compliance. No change made.</p>		
Northeast Power Coordinating Council	No	<p>The Applicability language used in FAC-003-X is different from that used in FAC-003-3. The language used in FAC-003-X uses “and” in several places which leads to confusion and a probable “null” result, whereas the language in FAC-003-3 is more straightforward and makes use of “or”. The FAC-003-3 applicability language should be used in FAC-003-X. The explanation of what is meant by line of sight should be incorporated in the Applicability Section wording as standards, at NERC’s direction, are supposed to be getting away from the use of footnotes.</p>
<p>Response: Thank you for your comment. The SDT sought to keep the language of 4.3.1 of FAC-003-X consistent with the formatting in 4.2.1 of FAC-003-X. The SDT does not believe the language in Version X can lead to a “null” result; we believe the language is as clear as possible as written now that the formatting has been updated to better reflect the formatting in FAC-003-3. No change made.</p>		
NextEra Energy, Inc.	No	<p>Under the line of sight approach, a generation lead would be exempt from the requirements of FAC-003-3 if personnel can see the generation lead corridor and the generation lead is less than a mile. The rationale provided to support of this proposal is that “Stakeholders have generally supported the rationale for exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit.”</p> <p>However, there is no data that supports that generation leads of less than a mile are categorically not subject to vegetation contacts and outages. Further, in practice this approach will unduly discriminate against longer</p>



Organization	Yes or No	Question 1 Comment
		<p>generator leads, many of which are associated with renewable energy resource, such as wind and solar.</p> <p>NextEra Energy Inc. (NextEra) believes a more technically sound approach is that all generator leads be subject to FAC-003-3, with the opportunity to be exempted from FAC-003-3 regulation upon an affirmative demonstration that no vegetation threat exists.</p> <p>To implement this approach, NextEra proposes that FAC-003-3 applicability 4.3.1 be revised to read as follows: “Overhead transmission lines, including generation leads, beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner and are:4.3.1.1. Operated at 200kV or higher; or 4.3.1.2. Operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator; or. 4.3.1.3. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.”</p> <p>NextEra would also propose to add a new section 4.3.2 that reads as follows:”If a Generator Owner or Transmission Owner can demonstrate that the entire Right-of-Way is paved or otherwise devoid of vegetation, and reasonably expected to remain so, the Generation Owner or Transmission Owner is exempt from FAC-003-3.”</p> <p>In addition, NextEra proposes that the drafting team consider a megawatt (MW) threshold for a generating plant from both a stand-alone and aggregate bases. For example, it is unlikely that vegetation contact tripping a 50 megawatt generator (or a generator of 100 MWs in the aggregate) connected to a robust transmission system with a large amount of load and generation will adversely impact reliability.</p> <p>Thus, NextEra proposes the addition of a provision that exempts a generation lead for stand-alone generators of 50 MWs and below and</p>

Organization	Yes or No	Question 1 Comment
		<p>generators in the aggregate of 100 MWs and below, unless there is an affirmative request for the generator to comply with FAC-003-3 by a Transmission Operator or Reliability Coordinator. Such a provision could read as follows: "Unless a Transmission Operator or Reliability Coordinator requests in writing that a stand-alone generator of 50 Megawatts (MWs) or below (with a 200 kV or above generation lead) or a generator in the aggregate of 100 MWs or below (with a 200 kV or above generation lead) comply with FAC-003-3, these classes of generators and their associated generation leads are exempt from complying with FAC-003-3. In the event a Transmission Operator or Reliability Coordinator requests in writing that a stand-alone generator of 50 Megawatts (MWs) or below (with a 200 kV or above generation lead) or a generator in the aggregate of 100 MWs or below (with a 200 kV or above generation lead) comply with FAC-003-3, the associated registered entity shall have one-year from the date of the written correspondence to come into compliance with FAC-003-3."</p>
<p><b>Response:</b> Thank you for your comment. The SDT appreciates this discussion, and had many similar discussions during its own deliberations. We maintain that the addition of the reference to "clear line of sight" is clarifying and helps support the rationale behind the one mile exemption. A line less than one mile that passes through a dense grove should not be exempt from this standard, but a line that is less than one mile and is either (1) staffed and within line of sight or (2) over a paved surface <i>should</i> be exempt. And because there are many GOs whose lines would fall into these categories, the SDT believes the exemption is necessary and prevents GOs with little to no reliability risk from incurring undue cost and compliance risk in the development and maintenance of a vegetation management plan. In sum, the SDT has considered all relevant stakeholder comments and is satisfied that we have determined the appropriate language to address the reliability gap. No change made.</p>		
Dynergy	No	<p>Using the switchyard fence is too restrictive. There could be too many different layouts to keep it fair for all GO's. For example, there could be an obstruction if limited to standing at the existing switchyard fence but if one were to move a short distance away (i.e. corner of GO's building) then it could be possible to see both ends of the tie line. This would also meet the intent of the added language since it is now within line of sight. I</p>

Organization	Yes or No	Question 1 Comment
		<p>recommend deleting "switchyard fence". Also, in order to account for a GO not being able to dictate what happens inside a TO's switchyard, I recommend adding "entry or" between "of" and "interconnection".</p>
<p><b>Response:</b> Thank you for your comment. The SDT appreciates this discussion, and had many similar discussions during its own deliberations. The SDT considered many options for a starting point, and believes that using the fixed starting point of the switchyard fence is best for eliminating confusion and any discretion on the part of a Generator Owner or an auditor. The SDT intends for the phrase “from the generating station switchyard fence to the point of interconnection” to mean that there is a clear line of sight from any point along that length of line. In sum, the SDT has considered all relevant stakeholder comments and is satisfied that we have determined the appropriate language to address the reliability gap. No change made.</p>		
<p>Wisconsin Electric; Wisconsin Electric Power Co.; Wisconsin Electric Power Marketing; Wisconsin Energy Corp.</p>	<p>No</p>	<p>We strongly oppose the addition of the “clear” line of sight criteria to the Applicability. The report of the GOTO Task Force, as well as prior draft revisions to FAC-003, included a test based solely on circuit length, which is sufficient in our view to assure that the BES is not at risk due to vegetation issues on generator tie lines. The expansion to include short tie lines, including those entirely on the Generator Owner’s property which may not meet the line of sight qualifier, has no benefit to reliability. Rather, the expanded applicability and the requirement for a formal vegetation management program in these cases will consume resources for compliance that are better used for actual reliability improvements.</p>
<p><b>Response:</b> Thank you for your comment. The SDT appreciates this discussion, and had many similar discussions during its own deliberations. We maintain that the addition of the reference to “clear line of sight” is clarifying and helps support the rationale behind the one mile exemption. A line less than one mile that passes through a dense grove should not be exempt from this standard, but a line that is less than one mile and is either (1) staffed and within line of sight or (2) over a paved surface <i>should</i> be exempt. The SDT has considered all relevant stakeholder comments and is satisfied that we have determined the appropriate language to address the reliability gap. No change made.</p>		
<p>ExxonMobil Research and Engineering</p>	<p>No</p>	<p>While it is clear that the SDT is attempting to include those facilities owned by Generator Owners that travel long distances down right-of-ways, the</p>

Organization	Yes or No	Question 1 Comment
		<p>applicability section of FAC-003-X and FAC-003-3, as written, require industrial complexes with cogeneration facilities to develop Transmission Vegetation Management Programs for generator lead lines that are not exposed to vegetation.</p> <p>Industrial cogeneration location is typically chosen based on the availability of fuel, need for steam, or availability of real estate. This can result with the generation facilities (including the GSU transformer substation) being located deep within the plant with long cable routes and multiple substation connections between the GSU transformer substation and utility interconnection facility located near the perimeter of the industrial complex’s fence line. Additionally, the routes of these generator lead lines fundamentally differ in nature from a typical IPP’s generator lead line route. Since they are located within the fence line of an industrial complex, the routes rarely contain vegetation; are frequently travelled by plant personnel; rarely run in straight lines (i.e. no single line of sight); and frequently terminate at a facility located at the fence line of the industrial complex where a transmission company takes ownership of the power lines that leave the industrial complex. Furthermore, the use of the term “generating station switchyard” may result in inconsistent enforcement of the Transmission Vegetation Management Program Reliability Standard as the use of the term implies there is only one substation located within a Generator Owner’s complex. Typically, there are multiple substations that connect an industrial complex’s generator lead-line to the utility interconnection facility located near the perimeter of the industrial complex’s fence line. The two obvious interpretations for the “generating station switchyard” are the substation that is directly connected to the generator’s GSU, and the utility interconnection facility. The concerns raised by NERC and FERC staff related generator owned transmission like assets originate with those conductors that leave the Generator Owner’s complex’s fence line and travel long distances down vacant right-of-ways,</p>

Organization	Yes or No	Question 1 Comment
		<p>and, therefore, the applicability of those Reliability Standards that apply to transmission facilities should start with the fence line.</p> <p>Since the Bulk Electric System is contiguous, reliability concerns related to the facilities between the GSU transformer substation and utility interconnection facility are covered by those Reliability Standards that apply to Generator Owners and Generator Operators. In order to account for the different nature of industrial complex’s generation facilities, the SDT should consider re-phrasing the applicability section of FAC-003-X and FAC-003-3 to start counting the length of a generator lead line at the fence line of the Generator Owner’s complex and not the generating station switchyard.</p>
<p><b>Response: Thank you for your comment. The SDT appreciates this discussion, and had many similar discussions during its own deliberations. The SDT considered many options for a starting point, and for language in general within this qualifier, and it believes that using the fixed starting point of the switchyard fence is best for eliminating confusion and any discretion on the part of a Generator Owner or an auditor. In sum, the SDT has considered all relevant stakeholder comments and is satisfied that we have determined the appropriate language to address the reliability gap, while exempting the most common lines with little to no reliability risk for a vegetation issue. No change made.</b></p>		
<p>City of Bartow, Florida; City of Clewiston; Florida Municipal Power Agency; Beaches Energy Services</p>	<p>Affirmative</p>	<p>Although we are supporting the change, the added applicability language for GOs is ambiguous as to whether the qualifier "operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region" applies to both portions of the applicability (e.g., 1) &gt; 1 mile and 2) no clear line of sight), or just to the second no clear line of sight applicability. FMPA assumes that the qualifier applies to both. We recommend re-arranging of the sentence to make this clearer by moving the qualifier to the beginning of the sentence instead of the end of the sentence.</p>
<p><b>Response: Thank you for your comment. The SDT agrees that the qualifier applies to both (1) and (2) in the qualifier language and used that language formatting to keep the formatting of 4.2.1 of FAC-003-X consistent with 4.1.1 of FAC-003-X. No change</b></p>		

Organization	Yes or No	Question 1 Comment
made.		
American Wind Energy Association	Affirmative	<p>AWEA supports the modifications in this standard, along with the other standards modification under Project 2010-07, as a reasonable approach to addressing the perceived reliability concerns with generator tie lines. We believe a consistent approach for all Generator Owners and Generator Operators that does not require registration as a Transmission Owner or Transmission Operator is the most efficient and effective way to address these concerns.</p>
<p><b>Response: The SDT thanks you for your comment and support.</b></p>		
BrightSource Energy, Inc.	Affirmative	<p>BrightSource would like to thank the SDT for the effort in developing the standard. Our comment is more on providing more clarification. Depending on the agreements between the TO and the GO, the Point of Interconnection is not necessarily the point of change of ownership of the transmission facilities. For example, the GO may own the portion of the Gen-tie from the generating plant to the last tower outside the TO’s substation and the TO owns the line drop from the last tower to the termination equipment inside the TO substation. So to avoid confusion later we suggest that we modify P4.3.1 by adding “to the point of change of ownership or” as follows: “4.3.1. Generator Owner that owns an overhead transmission line(s) that (1) extends greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of change of ownership or to the point of interconnection with a Transmission Owner’s Facility or (2) does not have a clear line of sight<sup>1</sup> from the generating station switchyard fence to the point of interconnection with a Transmission Owner’s Facility and is operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.” Thank you.</p>

Organization	Yes or No	Question 1 Comment
<p><b>Response: The SDT thanks you for your comment and support. The SDT considered many different language choices for its qualifying language, and it believes that “point of interconnection” is a clear phrase that will be understood and appropriately applied. No change made.</b></p>		
<p>Indiana Municipal Power Agency</p>	<p>Affirmative</p>	<p>IMPA supports the change, but would add the comment that the added applicability language for GOs is ambiguous as to whether the qualifier "operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region" applies to both portions of the applicability which are 1) &gt; 1 mile and 2) no clear line of sight), or just to the second portion for no clear line of sight applicability. IMPA assumes that the qualifier applies to both. We recommend reorganizing the sentence to make this more clear by moving the qualifier to the beginning of the sentence.</p>
<p><b>Response: Thank you for your comment. The SDT agrees that the qualifier applies to both (1) and (2) in the exemption language and used that language formatting to keep the formatting of 4.2.1 of FAC-003-X consistent with the formatting in 4.1.1 of FAC-003-X. No change made.</b></p>		
<p>Nebraska Public Power District</p>	<p>Affirmative</p>	<p>NPPD joins the comments submitted by the MRO NSRF (Midwest Reliability Organization - NERC Standards Review Forum)</p>
<p>Midwest Reliability Organization</p>	<p>Affirmative</p>	<p>Please refer to comments made by MRO NSRF.</p>
<p>Muscatine Power &amp; Water</p>	<p>Affirmative</p>	<p>Please see comments submitted by the MRO NERC Standards Review Forum.</p>
<p>Lakeland Electric</p>	<p>Affirmative</p>	<p>See FMPA comments</p>
<p>Great River Energy</p>	<p>Affirmative</p>	<p>See NSRF comments</p>
<p>Bonneville Power Administration</p>	<p>Yes</p>	<p>BPA has no other comments or concerns at this time.</p>

Organization	Yes or No	Question 1 Comment
NERC Compliance Policy	Yes	<p>Dominion offers the following comments on the Implementation Plan for FAC-003-3:</p> <ol style="list-style-type: none"> <li>1. The last paragraph on page 2 refers to FAC-003-3 Requirement 1.3. FAC-003-3 does not appear to contain a Requirement 1.3; therefore, Dominion recommends that the reference in the Implementation Plan be clarified.</li> <li>2. The 3rd paragraph on page 3 refers to FAC-003-3 Requirement 1.2. FAC-003-3 does not appear to contain a Requirement 1.2; therefore, Dominion recommends that the reference in the Implementation Plan be clarified.</li> </ol>
<p><b>Response: Thank you for these suggestions. These references have been removed.</b></p>		
MRO NSRF	Yes	<p>The NSRF agrees with the clarifying changes related to adding the phrase “.....do not have a clear line of sight from the generating station switchyard fence to the point of interconnection with a Transmission Owner’s Facility.....”, however, have the following comment for SDT consideration:</p> <ul style="list-style-type: none"> <li>o The Evidence Retention in FAC-003-3, Part C, Compliance, and Section 1.2 implies that an entity is required to retain evidence for the time period since the last audit. Since Generator Owners’ audit cycles are six (6) years, and the following paragraph states that to show compliance for R1, R2, R3, R5, R6 and R7 is three calendar years unless directed by the CEA to retain longer as part of an investigation, this section should be clarified to require six years retention for applicable Generator Owners.</li> </ul>
<p><b>Response: Thank you for your comment. The SDT believes the data retention section is appropriate as written. No change made.</b></p>		
Edison Mission Marketing & Trading	Yes	
Alabama Municipal Electric Authority	Yes	



Organization	Yes or No	Question 1 Comment
American Electric Power	Yes	
Public Service Enterprise Group	Yes	
ACES Power Marketing	Yes	
Essential Power, LLC	Yes	
Ingleside Cogeneration LP	Yes	

END OF REPORT

## **Exhibit F**

### **Analysis of how VRFs and VSLs Were Determined Using Commission Guidelines**

**Project 2010-07—Generator Requirements at the Transmission Interface  
Justification for Nonbinding Poll**

R#	Compliance with NERC's VSL Guidelines	<b>Guideline 1</b>  Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	<b>Guideline 2</b>  Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties  Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent  Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	<b>Guideline 3</b>  Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	<b>Guideline 4</b>  Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
FAC-001-1 R1	The drafting team made no changes to the R1 VSLs filed by NERC staff on March 21, 2011 (in Supplemental Information to the NERC Compliance Filing in Response to the Order on Violation Severity Levels Proposed by the ERO). Because the drafting team made no changes to R1, the team determined that any further changes to R1's VSLs would be outside of the scope of Project 2010-07.	The drafting team made no changes to the R1 VSLs filed by NERC staff on March 21, 2011 (in Supplemental Information to the NERC Compliance Filing in Response to the Order on Violation Severity Levels Proposed by the ERO), except to correct typographical errors.. Because the drafting team made no changes to R1, the team determined that any further changes to R1's VSLs would be outside of the scope of Project 2010-07.	The drafting team made no changes to the R1 VSLs filed by NERC staff on March 21, 2011 (in Supplemental Information to the NERC Compliance Filing in Response to the Order on Violation Severity Levels Proposed by the ERO), except to correct typographical errors. Because the drafting team made no changes to R1, the team determined that any further changes to R1's VSLs would be outside of the scope of Project 2010-07.	The drafting team made no changes to the R1 VSLs filed by NERC staff on March 21, 2011 (in Supplemental Information to the NERC Compliance Filing in Response to the Order on Violation Severity Levels Proposed by the ERO), except to correct typographical errors. Because the drafting team made no changes to R1, the team determined that any further changes to R1's VSLs would be outside of the scope of Project 2010-07.	The drafting team made no changes to the R1 VSLs filed by NERC staff on March 21, 2011 (in Supplemental Information to the NERC Compliance Filing in Response to the Order on Violation Severity Levels Proposed by the ERO), except to correct typographical errors. Because the drafting team made no changes to R1, the team determined that any further changes to R1's VSLs would be outside of the scope of Project 2010-07.
FAC-001-1 R2	The VSLs for R2 are written in accordance with NERC's VSL Guideline's formatting recommendations. The requirement is not of the pass/fail variety, so the VSL assignments have been gradated based on when the Generator Owner documented and published the Facility connection requirements. As is recommended by NERC's VSL Guidelines, the drafting team	Because this is a new requirement, there is no current level of compliance with which the VSL assignments can be compared.	The requirement has gradated VSLs; therefore, Guideline 2a is not applicable. The gradated VSLs ensure uniformity and consistency among all approved Reliability Standards in the determination of penalties.  The proposed text is clear, specific, and does not contain general, relative or subjective language (and is not subject to the	The drafting team compared the VSLs to the requirement language to ensure that the VSLs do not redefine or undermine the requirement's reliability goal. The VSL assignments are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.	The VSLs are based on a single violation, not on a cumulative number of violations of the same requirement over a period of time, thus fulfilling Guideline 4.

**Project 2010-07—Generator Requirements at the Transmission Interface  
Justification for Nonbinding Poll**

R#	Compliance with NERC’s VSL Guidelines	<b>Guideline 1</b>  Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	<b>Guideline 2</b>  Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties  Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent  Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	<b>Guideline 3</b>  Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	<b>Guideline 4</b>  Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
	identified a reasonable delay for the Lower VSL and then used 10-day increments to develop the Moderate, High, and Severe VSLs.		possibility of multiple interpretations), satisfying Guideline 2b.		
FAC-001-1 R3	For its proposed changes to VSLs for FAC-001-1 R3, the drafting team used the FERC-approved VSLs (then FAC-001-0 R2) in 135 FERC ¶ 61,166 as a starting point. The VSLs were already appropriately gradated with penalties based on the recommendation for requirements with parts that contribute equally to the requirement, and removing the second half of R3’s Severe VSL simply avoids any double jeopardy compliance issues, as indicated in the Guideline 2 explanation.	The drafting team’s slight modification to the Severe VSL for R3 does not signal a lower compliance threshold than previously existed.	The requirement has gradated VSLs; therefore, Guideline 2a is not applicable. The gradated VSLs ensure uniformity and consistency among all approved Reliability Standards in the determination of penalties.  The drafting team determined that the second half of the Severe VSL in R3 (“The responsible entity does not have Facility connection requirements”) could lead to double jeopardy because of its redundancy with the Severe VSLs in R1 (“The Transmission Owner did not develop Facility connection requirements”) and R2 (“The Generator Owner failed to document and publish and thereafter maintain Facility connection requirements until more than 80 days...”). Thus, the	The drafting team compared the VSLs to the requirement language to ensure that the VSLs do not redefine or undermine the requirement’s reliability goal. After modifying “Transmission Owner” to “responsibility entity”, the VSL assignments are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.	The VSLs are based on a single violation, not on a cumulative number of violations of the same requirement over a period of time, thus fulfilling Guideline 4.

**Project 2010-07—Generator Requirements at the Transmission Interface  
Justification for Nonbinding Poll**

R#	Compliance with NERC's VSL Guidelines	<b>Guideline 1</b>  Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	<b>Guideline 2</b>  Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties  Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent  Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	<b>Guideline 3</b>  Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	<b>Guideline 4</b>  Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
			second half of the VSL for R3 has been deleted.  With this change, the text is clear, specific, and does not contain general, relative or subjective language (and is not subject to the possibility of multiple interpretations), satisfying Guideline 2b.		
FAC-001-1 R4	The drafting team made no changes to the R4 VSLs (then VSLs for R3) approved by FERC in 135 FERC ¶ 61,166. Because, with this posting, the drafting team made no changes to R4 compared to the FERC approved version (then R3), the team determined that any further changes to R4's VSLs would be outside of the scope of Project 2010-07.	The drafting team made no changes to the R4 VSLs (then VSLs for R3) approved by FERC in 135 FERC ¶ 61,166. Because the drafting team made no changes to R4 compared to the FERC approved version (then R3), the team determined that any further changes to R4's VSLs would be outside of the scope of Project 2010-07.	The drafting team made no changes to the R4 VSLs (then VSLs for R3) approved by FERC in 135 FERC ¶ 61,166. Because the drafting team made no changes to R4 compared to the FERC approved version (then R3), the team determined that any further changes to R4's VSLs would be outside of the scope of Project 2010-07.	The drafting team made no changes to the R4 VSLs (then VSLs for R3) approved by FERC in 135 FERC ¶ 61,166. Because the drafting team made no changes to R4 compared to the FERC approved version (then R3), the team determined that any further changes to R4's VSLs would be outside of the scope of Project 2010-07.	The drafting team made no changes to the R4 VSLs (then VSLs for R3) approved by FERC in 135 FERC ¶ 61,166. Because the drafting team made no changes to R4 compared to the FERC approved version (then R3), the team determined that any further changes to R4's VSLs would be outside of the scope of Project 2010-07.

**Project 2010-07—Generator Requirements at the Transmission Interface  
Justification for Nonbinding Poll**

**VRFs for FAC-001-1:**

The VRFs for FAC-001-1 were transferred from NERC's VRF Matrix – which includes VRFs that have already been approved by FERC – to bring the formatting of the standard up to date. A Medium VRF was added to new Requirement R2, which applies to Generator Owners, to match the Medium VRF for the comparable Requirement R1, which applies to Transmission Owners.

**Exhibit G**

**Record of Development of Proposed Reliability Standard**

## Project 2010-07

### Generator Requirements at the Transmission Interface

#### Related Files

**Status:**

FAC-001-1, FAC-003-3, PRC-004-2.1a, and PRC-005-1.1b and all associated documents were adopted by NERC's Board of Trustees (BOT) in February and May 2012. They are pending regulatory filing.

**Purpose/Industry Need:**

The proposed changes to the requirements and the addition of new requirements will add significant clarity to Generator Owners and Generator Operators regarding their reliability standard obligations at the interface with the interconnected grid.

Draft	Action	Dates	Results	Consideration of Comments
<p><b>FAC-003-x</b> Clean (143)   Redline to Last Posted(144)   Redline to Last Approved(145)</p> <p><b>Implementation Plan</b> Clean(146)   Redline to Last Posted(147)</p> <p><b>FAC-003-3</b> Clean(148)   Redline to Last Posted(149)   Redline to Last Approved(150)</p> <p><b>Implementation Plan</b> Clean(151)   Redline to Last Posted(152)</p> <p><b>Consideration of Comment Report</b> (FAC-003-3 and FAC-003-x - for reference; from successive ballot that took place March 9 - April 9, 2012) Clean(153)</p> <p><b>PRC-005-1.1b</b> Clean(154)   Redline to Last Approved (155)</p>	<p>Recirculation Ballot</p> <p>Info(161)</p> <p>Vote&gt;&gt;</p>	<p>04/24/12 – 05/03/12</p>	<p>Summary(162)</p> <p>Ballot Results:</p> <p>FAC-003-3(163) FAC-003-x(164) PRC-005-1.1b(165)</p>	



<b>Implementation Plan</b> <a href="#">Clean(156)</a>   <a href="#">Redline to Last Posted(157)</a>				
<b>Consideration of Comment Report</b> (PRC-005-1.1b for reference; from initial ballot that took place from March 2 - April 16, 2012) <a href="#">Clean(158)</a>				
<b>Technical Justification Document</b> (for reference; updated from the version posted in March 2012) <a href="#">Clean(159)</a>   <a href="#">Redline(160)</a>				

On January 20, 2012, Exelon submitted a Level 1 Appeal of the process, challenging the results of the recirculation ballots of FAC-003-3 and FAC-003-X that concluded on Dec. 23, 2011. The NERC Vice President of Standards and Training and then the Standards Committee's Executive Committee reviewed the appeal and found for the appellant, determining that the modifications the SDT made to the applicability of FAC-003-3 and FAC-003-x prior to the recirculation ballot were substantive. Consequently the results of the recirculation ballots for FAC-003-3 and FAC-003-x have been declared void. The SDT has made minor modifications to the standards and posted them for a parallel formal comment period and successive ballot.

[Exelon's Level 1 Appeal\(141\)](#)

[NERC Vice President of Standards and Training Response\(142\)](#)

<b>FAC-003-x</b> <a href="#">Clean(122)</a>   <a href="#">Redline to Last Posted(123)</a>	Successive Ballot	3/30/12 - 04/09/12 (closed)	<b>Info(136)</b>	
<b>FAC-003-3</b> <a href="#">Clean(124)</a>   <a href="#">Redline to Last Posted(125)</a>	<a href="#">Info(135)</a>		Full Records: <a href="#">FAC-003-x(137)</a> <a href="#">FAC-003-3(138)</a>	
<b>Implementation Plans</b> <b>FAC-003-x</b> <a href="#">Clean(126)</a>	<a href="#">Vote&gt;&gt;</a>			
<b>FAC-003-3</b> <a href="#">Clean(127)</a>	Formal Comment Period	03/09/12 - 04/09/12 (closed)	<a href="#">Comments Received(139)</a>	
<b>Supporting Materials:</b> <a href="#">Unofficial Comment Form (Word)(128)</a>	<a href="#">Submit Comments&gt;&gt;</a>			
<a href="#">Standards Committee Executive Committee 2/23/12 meeting minutes</a>				<a href="#">Consideration of Comments(140)</a>

<p>(directing that Recirculation Ballot Results be voided and work remanded to the SDT) <b>(129)</b></p> <p>Letter from SC Chairman to Project 2010-07 SDT Chair <b>(130)</b></p> <p><b>Technical Justification Document</b> (for reference; updated from the version posted in December 2011) Clean <b>(131)</b>   Redline <b>(132)</b></p> <p><b>Consideration of Comment Report</b> (for reference; updated from successive ballot that took place October 5-November 18, 2011) Clean <b>(133)</b>   Redline <b>(134)</b></p>				
<p><b>PRC-005-1.1a</b> Clean <b>(112)</b>   Redline to Last Approved <b>(113)</b></p> <p><b>Implementation Plan</b> Clean <b>(114)</b></p> <p><b>Supporting Materials</b> Unofficial Comment Form (Word) <b>(115)</b></p>	<p>Initial Ballot</p> <p>Updated Info <b>(116)</b> Info <b>(117)</b></p> <p>Vote &gt;&gt;</p>	<p>04/06/12 - 04/16/12 (closed)</p>	<p>Info <b>(118)</b></p> <p>Full Record <b>(119)</b></p>	
	<p>Formal Comment Period</p> <p>Submit Comments &gt;&gt;</p>	<p>03/02/12 - 04/16/12 (closed)</p>	<p>Comments Received <b>(120)</b></p>	<p>Consideration of Comments <b>(121)</b></p>
	<p>Join Ballot Pool &gt;&gt;</p>	<p>03/02/12 - 03/31/12 (closed)</p>		
<p><b>FAC-001-1</b> Clean <b>(100)</b>   Redline to Last Approved <b>(101)</b> Implementation Plan <b>(102)</b></p> <p><b>PRC-004-2.1a</b> Clean <b>(103)</b>   Redline to Last Approved <b>(104)</b> Implementation Plan <b>(105)</b></p> <p><b>Supporting Materials:</b></p>				

<p>Technical Justification  <a href="#">Clean(106)</a>   <a href="#">Redline(107)</a></p> <p>Technical Justification for FAC-001-1(108)</p> <p>Sole-use Generator Interconnection Facility: <a href="#">Diagram 1(109)</a></p> <p>Sole-use Generator Interconnection Facility: <a href="#">Diagram 2(110)</a></p> <p>VRF and VSL Justification(111)</p>				
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<p>FAC-001-1 VRFs and VSLs  <a href="#">Clean(94)</a>   <a href="#">Redline to last approved(95)</a></p> <p><b>Supporting Materials:</b></p> <p><a href="#">VRF and VSL Justification(96)</a></p> <p><a href="#">FAC-001-1 Implementation Plan(97)</a></p>	<p>Non-binding Poll</p> <p><a href="#">Info(98)</a></p> <p><a href="#">Vote&gt;&gt;</a></p>	<p>01/04/12 - 01/13/12 (closed)</p>	<p><a href="#">Non-Binding Poll Results(99)</a></p>	
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<p><b>FAC-001-1</b>  <a href="#">Clean (65)</a>   <a href="#">Redline to Last Posted(66)</a>    <a href="#">Redline to Last Approved(67)</a></p> <p><b>FAC-003-X</b>  <a href="#">Clean (68)</a>   <a href="#">Redline to Last Posted(69)</a></p> <p><b>FAC-003-3</b>  <a href="#">Clean (70)</a>   <a href="#">Redline to Last Posted(71)</a></p> <p><b>PRC-004-2.1</b>  <a href="#">Clean(72)</a>   <a href="#">Redline to Last Posted(73)</a>   <a href="#">Redline to Last Approved(74)</a></p> <p><b>Implementation Plans</b>  FAC-001-1  <a href="#">Clean(75)</a></p> <p>FAC-003-3  <a href="#">Clean(76)</a></p>	<p>Recirculation Ballots</p> <p><a href="#">Info(84)</a></p> <p><a href="#">Vote&gt;&gt;</a></p>	<p>12/14/11 - 12/23/11 (closed)</p>	<p><a href="#">Summary(85)</a></p> <p>Full Record Reports:  <a href="#">FAC-001-1(86)</a>  <a href="#">FAC-003-X(87)</a>  <a href="#">FAC-003-3(88)</a>  <a href="#">PRC-004-2.1(89)</a></p>	<p>Full Record Reports  (NOTE that the results of the recirculation ballots of FAC-003-3 and FAC-003-x were voided as a</p>
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<p>FAC-003-X Clean(77)</p> <p>PRC-004-2.1 Clean(78)</p> <p><b>Supporting Materials:</b> Technical Justification Clean (79)  Redline(80)</p> <p>Technical Justification for FAC-001-1(81)</p> <p>Sole-use generator interconnection Facility: Diagram 1(82)</p> <p>Sole-use generator interconnection Facility: Diagram 2(83)</p>				<p>result of an appeal, and a successive ballot of the two standards was conducted. The appeal and response are posted on this project page.)</p> <p>FAC-001-1(90) FAC-003-x(91) FAC-003-3(92) PRC-004-2.1(93)</p>
<p><b>FAC-001-1</b> Clean(32)   Redline to Last Posted(33)   Redline to Last Approved(34)</p> <p><b>FAC-003-X</b> Clean (35)   Redline to Last Posted(36)   Redline to Last Approved(37)</p>	<p>Join Ballot Pool</p> <p>Info(54)</p> <p>Join&gt;&gt;</p>	<p>10/05/11 - 11/04/11 (closed)</p>		
<p><b>FAC-003-3</b> Clean(38)   Redline to Last Posted(39)</p> <p>FAC-003-3 with revised VSLs based on FAC-003-2 adopted by NERC BOT (added 11/09/11) Clean(40)   Redline to version of FAC-003-3 posted 10/05/11(41)</p> <p><b>PRC-004-2.1</b> Clean(42)   Redline to Last Approved(43)</p>	<p>Initial Ballot</p> <p>Updated Info(55)</p> <p>Info(56)</p> <p>Vote&gt;&gt;</p>	<p>11/09/11 - 11/18/11 (closed)</p>	<p>Summary(58)</p> <p>Full Record Report:</p> <p>FAC-001-1(59) FAC-003-X(60) FAC-003-3(61) PRC-004-2.1(62)</p>	
<p><b>Implementation Plans</b> FAC-001-1 Clean (44)   Redline(45)</p> <p>FAC-003-3 Clean(46)   Redline(47)</p> <p>FAC-003-X</p>	<p>Comment Period</p> <p>Info(57) Submit Comments&gt;&gt;</p>	<p>10/05/11 - 11/18/11 (closed)</p>	<p>Comments Received(63)</p>	<p>Consideration of Comments(64)</p>

<p>Clean(48)   Redline(49)</p> <p>PRC-004-2 Clean(50)</p> <p><b>Supporting Materials:</b> Technical Justification(51)</p> <p>Technical Justification for FAC-001-1(52)</p> <p>Unofficial Comment Form (Word)(53)</p>				
<p><b>FAC-001-1</b></p> <p>Clean(18)   Redline to last approved(19)</p> <p>Implementation Plan(20)</p> <p><b>FAC-003-3</b></p> <p>Clean(21)   Redline to last approved(22)</p> <p>Implementation Plan(23)</p> <p><b>FAC-003-X</b></p> <p>Clean(24)   Redline to Project 2007-07 last balloted(25)</p> <p>Implementation Plan(26)</p> <p><b>Supporting Materials</b></p> <p>Background Resource (White Paper)(27)</p> <p>Comment Form (Word) (28)</p>	<p>Formal Comment Period</p> <p>Info(29)</p> <p>Submit Comments&gt;&gt;</p>	<p>06/17/11 - 07/17/11 (closed)</p>	<p>Comments Received(30)</p>	<p>Consideration of Comments(31)</p>
<p>White Paper(12)</p> <p><b>Supporting Materials</b> Attachment 1 (13)   Attachment 2(14)</p>	<p>Informal Comment Period</p> <p>Info(15)</p> <p>Submit Comments&gt;&gt;</p>	<p>03/04/11 - 04/04/11 (closed)</p>	<p>Comments Received(16)</p>	<p>Summary Consideration of Comments(17)</p>

<p>SAR  <a href="#">Clean(3)</a>   <a href="#">Redline(4)</a></p>				
<p>Generator Requirements at the  Transmission Interface (GOTO)</p> <p><a href="#">SAR(5)</a></p> <p><a href="#">Redline Standard Changes(6)</a></p> <p><b>Supporting Materials</b>  <a href="#">GOTO Final Report(7)</a>  <a href="#">Comment Form (Word) (8)</a></p>	<p>Comment  Period</p> <p><a href="#">Submit  Comments&gt;&gt;</a></p> <p><a href="#">Info(9)</a></p>	<p>02/12/10  -  03/15/10  (closed)</p>	<p><a href="#">Comments  Received(10)</a></p>	<p><a href="#">Consideration of  comments(11)</a></p>
<p>Drafting Team Nominations Open</p> <p><a href="#">Nomination Form (Word) (1)</a></p>	<p><a href="#">Submit  Nomination&gt;&gt;</a></p> <p><a href="#">Info(2)</a></p>	<p>02/12/10  -  03/01/10  (closed)</p>		

**Unofficial Nomination Form for the Drafting Team for Generator Requirements at the Transmission Interface — Project 2010-07**

Please **DO NOT** use this form. Please use the [electronic nomination form](#) located at the link below by **March 1, 2010**. If you have any questions, please contact David Taylor at [david.taylor@nerc.net](mailto:david.taylor@nerc.net) or by telephone at 609-651-5089.

[http://www.nerc.com/filez/standards/Project2010-07\\_GOTO\\_Project.html](http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html)

By submitting the following information you are indicating your willingness and agreement to actively participate in the Drafting Team meetings if appointed to the Drafting Team by the Standards Committee. This means that if you are appointed to the DT you are expected to attend all (or at least the vast majority) of the face-to-face DT meetings as well as participate in all the DT meetings held via conference calls and failure to do so shall result in your removal from the DT.

Name:	
Organization:	
Address:	
Telephone:	
E-mail:	
<p><b>Project 2010-07 Generator Requirements at the Transmission Interface:</b> The purpose of the SAR and associated definition and standard changes is to provide greater clarity to the requirements associated with Generator Interconnection Facilities. This includes adding/modifying some definitions, and adding/modifying some requirements to capture responsibilities for owning and operating the Generator Interconnection Facility, and to add requirements where necessary that should be applicable to Generator Operators regardless of the interconnection configuration.</p> <p>Please briefly describe your experience and qualifications directly related to the issues to be addressed by the Generator Requirements at the Transmission Interface Drafting Team. We are seeking a cross section of the industry to participate on the team, but in particular are seeking individuals who participated in the Ad Hoc Group for Generator Requirements at the Transmission Interface, and individuals who work for entities registered as generator owners, generator operators, and others with expertise in those activities associated with the new/modified requirements proposed with the SAR.</p> <p>Experience in developing standards inside or outside (i.e., IEEE, NAESB, ANSI, etc.) of the NERC process is beneficial, but is not required, and should be highlighted in the information submitted if applicable.</p>	
<p><b>Are you currently a member of any NERC or Regional Entity SAR or standard drafting team? If yes, please list each team here.</b></p> <p><input type="checkbox"/> No <input type="checkbox"/> Yes:</p>	

**Unofficial Nomination Form for Project 2010-07 – Generator Requirements at the Transmission Interface**

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**Have you previously worked on any NERC or Regional Entity SAR or standard drafting teams? If yes, please list them here.**

No  Yes:

**Please identify the NERC Reliability Region(s) in which your company operates and for which you are able to represent your company's position relative to the applicable issues while serving on the SAR drafting team:**

- |                                |                               |                               |                              |
|--------------------------------|-------------------------------|-------------------------------|------------------------------|
| <input type="checkbox"/> ERCOT | <input type="checkbox"/> MRO  | <input type="checkbox"/> RFC  | <input type="checkbox"/> SPP |
| <input type="checkbox"/> FRCC  | <input type="checkbox"/> NPCC | <input type="checkbox"/> SERC | <input type="checkbox"/> WEC |

Not Applicable or None of the Above

**Please identify the Industry Segment(s) for which you are able to represent on behalf of your company while serving on the SAR drafting team:**

- |                          |  |
|--------------------------|--|
| <input type="checkbox"/> | 1 – Transmission Owners  |
| <input type="checkbox"/> | 2 – RTOs and ISOs  |
| <input type="checkbox"/> | 3 – Load-serving Entities  |
| <input type="checkbox"/> | 4 – Transmission-dependent Utilities                                       |
| <input type="checkbox"/> | 5 – Electric Generators  |
| <input type="checkbox"/> | 6 – Electricity Brokers, Aggregators, and Marketers                        |
| <input type="checkbox"/> | 7 – Large Electricity End Users  |
| <input type="checkbox"/> | 8 – Small Electricity End Users  |
| <input type="checkbox"/> | 9 – Federal, State, and Provincial Regulatory or other Government Entities |



**Unofficial Nomination Form for Project 2010-07 – Generator Requirements at the Transmission Interface**

<input type="checkbox"/>	Regional Reliability Organizations and Regional Entities
<input type="checkbox"/>	Not applicable

**Which of the following Functional Entities<sup>1</sup> do you have expertise or responsibilities for which you are able to represent on behalf of your company while serving on the SAR drafting team:**

<input type="checkbox"/> Balancing Authority	<input type="checkbox"/> Planning Coordinator
<input type="checkbox"/> Compliance Enforcement Authority	<input type="checkbox"/> Transmission Operator
<input type="checkbox"/> Distribution Provider	<input type="checkbox"/> Transmission Owner
<input type="checkbox"/> Generator Operator	<input type="checkbox"/> Transmission Planner
<input type="checkbox"/> Generator Owner	<input type="checkbox"/> Transmission Service Provider
<input type="checkbox"/> Interchange Authority	<input type="checkbox"/> Purchasing-selling Entity
<input type="checkbox"/> Load-serving Entity	<input type="checkbox"/> Resource Planner
<input type="checkbox"/> Market Operator	<input type="checkbox"/> Reliability Coordinator

**Please provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group which you give us permission to contact in the event it is deemed necessary to do so.**

Name and Title:		Office Telephone:	
Organization:		E-mail:	
Name and Title:		Office Telephone:	
Organization:		E-mail:	

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<sup>1</sup> These functions are defined in the NERC Functional Model, which is available on the NERC Web site.



NORTH AMERICAN ELECTRIC  
RELIABILITY CORPORATION

## Standards Announcement

Standards Authorization Request (SAR) Comment and Drafting Team  
Nomination Periods Open

Project 2010-07: Generator Requirements at the Transmission Interface

Now available at: [http://www.nerc.com/filez/standards/Project2010-07\\_GOTO\\_Project.html](http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html)

### **Nominations for Drafting Team (through March 1, 2010)**

The Standards Committee is seeking industry experts to serve on the Generator Requirements at the Transmission Interface Drafting Team (see project background below).

If you are interested in serving on this drafting team, please complete this [electronic nomination form](#) by **March 1, 2010**.

### **Comment Period (through March 15, 2010)**

The Standards Committee has posted a proposed SAR for a 30-day comment period **ending on March 15, 2010**. Also posted are proposed revisions to existing standards and a copy of the final report published by the Ad Hoc Group for Generator Requirements at the Transmission Interface.

Please use this [electronic form](#) to submit comments. If you experience any difficulties in using the electronic form, please contact Lauren Koller at [Lauren.Koller@nerc.net](mailto:Lauren.Koller@nerc.net). An off-line, unofficial copy of the comment form is posted on the project page (see project background below).

### **Project Background**

On January 14, 2008, the NERC Board of Trustees Compliance Committee upheld the Western Electricity Coordinating Council's (WECC's) determination to register the New Harquahala Generating Company (Harquahala) as a Transmission Owner and Transmission Operator. This determination is based on Harquahala's 26-mile 500 kV interconnection facilities that connect the plant with the Hassayampa transmission substation. This decision was upheld by FERC and caused concern for Generator Owners and Generator Operators who owned only transmission "tie-line" facilities used to connect their generating facilities to a transmission substation.

In response to concerns from members of the generator segment regarding this decision, NERC conducted a survey in the Fall of 2008 to define and collect recommendations for resolving stakeholders concerns, and to review and highlight those Transmission Owner and Transmission Operator requirements that should be considered for generic applicability for Generator Owners and Generator Operators for their tie-line facilities. Based on the survey recommendations, NERC formed a group of industry representatives to "Evaluate existing NERC Reliability Standard requirements and develop a recommendation and possible standards authorization request to address gaps in reliability for interconnection facilities of the Generator Owner and expectations for the Generator Operator in operating those facilities. Propose strategies to address or resolve other related issues as appropriate." In November 2009, the group published [report](#) of its conclusions and recommendations.

This project is the result of those recommendations, which include proposed definitions and changes to existing standards to add clarity to Generator Owners and Generator Operators regarding their reliability standard obligations at the interface with the interconnected grid.

Project page: [http://www.nerc.com/filez/standards/Project2010-07\\_GOTO\\_Project.html](http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html)

### **Standards Development Process**

The [Reliability Standards Development Procedure](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

*For more information or assistance,  
please contact Shaun Streeter at [shaun.streeter@nerc.net](mailto:shaun.streeter@nerc.net) or at 609.452.8060.*

## Standard Authorization Request Form

Title of Proposed Standard	Various Standards Containing GO/GOP and TO/TOP Requirements
Request Date	January 15, 2010
SC Approval Date	January 20, 2010
Revised Date	November 30, 2010

SAR Requester Information	SAR Type <i>(Check a box for each one that applies.)</i>	
Name <a href="#">Ad Hoc Group for Generator Requirements at the Transmission Interface</a>	<input checked="" type="checkbox"/>	New Standard
Primary Contact <a href="#">Scott Helyer</a>	<input checked="" type="checkbox"/>	Revision to existing Standards
Telephone <a href="#">817-462-1512</a> Fax	<input type="checkbox"/>	Withdrawal of existing Standard
E-mail <a href="mailto:shelyer@tnsk.com">shelyer@tnsk.com</a>	<input type="checkbox"/>	Urgent Action

## Standards Authorization Request Form

**Purpose** (Describe what the standard action will achieve in support of bulk power system reliability.)

The proposed changes to the requirements and the addition of new requirements will add significant clarity to Generator Owners and Generator Operators regarding their reliability standard obligations at the interface with the interconnected grid.

**Industry Need** (Provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

Significant industry concern exists regarding the application of Transmission Owner and Transmission Operator requirements, and more generally, to the registration of Generator Owners and Generator Operators as Transmission Owners and Transmission Operators, based on the facilities that connect the generators to the interconnected grid. The final report of the Ad Hoc Group for Generator Requirements at the Transmission Interface evaluated the issue and proposes a number of changes that adds much needed clarity on the requirements for Generator Interconnection Facilities. Absent these revisions and additional requirements, Generator Owners and Generator Operators are subject to what some believe to be inappropriate registration as Transmission Owners and Transmission Operators to ensure coverage for certain reliability requirements. The modifications and additions recommended wholly and directly address the requirements for Generator Owners and Generator Operators regarding its Generator Interconnection Facilities, and add particular focus on the operation of the interface point at which operating responsibility shifts from the Generator Operator to the Transmission Operator.

The proposal also modifies certain of NERC's existing glossary terms and adds new terms to support the standards modifications.

**Brief Description** (Provide a paragraph that describes the scope of this standard action.)

32 NERC Reliability Standards contain language regarding generators or generating facilities for which greater clarity regarding its Generator Interconnection Facilities would ensure no reliability gap exists

12 requirements in FAC-003-1 - Transmission Vegetation Management should have their applicability expanded to include Generator Owners.

2 NERC Reliability Standards should have their applicability expanded to include Generator Operators to address general reliability gaps not attributable to their Generator Interconnection Facilities.

8 new Reliability Standard Requirements should be added to ensure the responsibilities for owning and operating the Generator Interconnection Facility are clear, and to address certain requirements that should apply to all generators regardless of interconnection configuration.

New NERC Glossary definitions are needed for Generator Interconnection Facility and Generator Interconnection Operational Interface, as well as modifications to Vegetation Inspection, Right-of-Way, Generator Owner, Generator Operator, and Transmission

**Detailed Description** (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.)

Refer to Final Report of the Ad hoc Group for Generator Requirements at the Transmission Interface.

Revisions to the latest versions of the following standards are included in the report and redline standard changes are included to accompany this SAR:

BAL-005

CIP-002

EOP-001, -003, -004, -008

FAC-001, -003, -008, -009

**Standards Authorization Request Form**

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IRO-005

MOD-010, -012

PER-001, -002

PRC-001, -004, -005

TOP-001, -002, -003, -004, -008

VAR-001, -002

**Standards Authorization Request Form**

**Reliability Functions**

<b>The Standard will Apply to the Following Functions</b> <i>(Check box for each one that applies.)</i>		
<input type="checkbox"/>	Reliability Assurer	Monitors and evaluates the activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the bulk power system within a Reliability Assurer Area and adjacent areas.
<input type="checkbox"/>	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
<input type="checkbox"/>	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
<input type="checkbox"/>	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
<input type="checkbox"/>	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
<input type="checkbox"/>	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within its portion of the Planning Coordinator's Area.
<input checked="" type="checkbox"/>	Transmission Owner	Owns and maintains transmission facilities.
<input checked="" type="checkbox"/>	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
<input type="checkbox"/>	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within the Transmission Planner Area.
<input type="checkbox"/>	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
<input type="checkbox"/>	Distribution Provider	Delivers electrical energy to the End-use customer.
<input checked="" type="checkbox"/>	Generator Owner	Owns and maintains generation facilities.
<input checked="" type="checkbox"/>	Generator Operator	Operates generation unit(s) to provide real and reactive power.
<input type="checkbox"/>	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
<input type="checkbox"/>	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

***Reliability and Market Interface Principles***

<b>Applicable Reliability Principles</b> <i>(Check box for all that apply.)</i>	
<input checked="" type="checkbox"/>	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
<input type="checkbox"/>	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
<input checked="" type="checkbox"/>	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
<input checked="" type="checkbox"/>	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
<input checked="" type="checkbox"/>	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
<input checked="" type="checkbox"/>	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
<input type="checkbox"/>	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
<input type="checkbox"/>	8. Bulk power systems shall be protected from malicious physical or cyber attacks.
<b>Does the proposed Standard comply with all of the following Market Interface Principles?</b> <i>(Select 'yes' or 'no' from the drop-down box.)</i>	
1. A reliability standard shall not give any market participant an unfair competitive advantage. <b>Yes</b>	
2. A reliability standard shall neither mandate nor prohibit any specific market structure. <b>Yes</b>	
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. <b>Yes</b>	
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. <b>Yes</b>	



**Standards Authorization Request Form**

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***Related Standards***

<b>Standard No.</b>	<b>Explanation</b>

***Related SARs***

<b>SAR ID</b>	<b>Explanation</b>

***Regional Variances***

<b>Region</b>	<b>Explanation</b>
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

## Standard Authorization Request Form

Title of Proposed Standard	Various Standards Containing GO/GOP and TO/TOP Requirements
Request Date	January 15, 2010
SC Approval Date	January 20, 2010
Revised Date	<u>November 30, 2010</u>

SAR Requester Information	SAR Type <i>(Check a box for each one that applies.)</i>	
Name Ad Hoc Group for Generator Requirements at the Transmission Interface	<input checked="" type="checkbox"/> <input type="checkbox"/>	New Standard
Primary Contact Scott Helyer	<input checked="" type="checkbox"/>	Revision to existing Standards
Telephone      817-462-1512 Fax	<input type="checkbox"/>	Withdrawal of existing Standard
E-mail            shelyer@tnsk.com	<input type="checkbox"/>	Urgent Action

## Standards Authorization Request Form

**Purpose** (Describe what the standard action will achieve in support of bulk power system reliability.)

The proposed changes to the requirements and the addition of new requirements will add significant clarity to Generator Owners and Generator Operators regarding their reliability standard obligations at the interface with the interconnected grid.

**Industry Need** (Provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

Significant industry concern exists regarding the application of Transmission Owner and Transmission Operator requirements, and more generally, to the registration of Generator Owners and Generator Operators as Transmission Owners and Transmission Operators, based on the facilities that connect the generators to the interconnected grid. The final report of the Ad Hoc Group for Generator Requirements at the Transmission Interface evaluated the issue and proposes a number of changes that adds much needed clarity on the requirements for Generator Interconnection Facilities. Absent these revisions and additional requirements, Generator Owners and Generator Operators are subject to what some believe to be inappropriate registration as Transmission Owners and Transmission Operators to ensure coverage for certain reliability requirements. The modifications and additions recommended wholly and directly address the requirements for Generator Owners and Generator Operators regarding its Generator Interconnection Facilities, and add particular focus on the operation of the interface point at which operating responsibility shifts from the Generator Operator to the Transmission Operator.

The proposal also modifies certain of NERC's existing glossary terms and adds new terms to support the standards modifications.

**Brief Description** (Provide a paragraph that describes the scope of this standard action.)

32 NERC Reliability Standards contain language regarding generators or generating facilities for which greater clarity regarding its Generator Interconnection Facilities would ensure no reliability gap exists

12 requirements in FAC-003-1 - Transmission Vegetation Management should have their applicability expanded to include Generator Owners.

2 NERC Reliability Standards should have their applicability expanded to include Generator Operators to address general reliability gaps not attributable to their Generator Interconnection Facilities.

8 new Reliability Standard Requirements should be added to ensure the responsibilities for owning and operating the Generator Interconnection Facility are clear, and to address certain requirements that should apply to all generators regardless of interconnection configuration.

New NERC Glossary definitions are needed for Generator Interconnection Facility and Generator Interconnection Operational Interface, as well as modifications to Vegetation Inspection, Right-of-Way, Generator Owner, Generator Operator, and Transmission

**Detailed Description** (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.)

Refer to Final Report of the Ad hoc Group for Generator Requirements at the Transmission Interface.

Revisions to the latest versions of the following standards are included in the report and redline standard changes are included to accompany this SAR:

BAL-005

CIP-002

EOP-001, -003, -004, -008

FAC-001, -003, -008, -009

**Standards Authorization Request Form**

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IRO-005

MOD-010, -012

PER-001, -002

PRC-001, -004, -005

TOP-001, -002, -003, -004, -008

VAR-001, -002

**Standards Authorization Request Form**

**Reliability Functions**

<b>The Standard will Apply to the Following Functions</b> <i>(Check box for each one that applies.)</i>		
<input type="checkbox"/>	Reliability Assurer	Monitors and evaluates the activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the bulk power system within a Reliability Assurer Area and adjacent areas.
<input type="checkbox"/>	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
<input type="checkbox"/>	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
<input type="checkbox"/>	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
<input type="checkbox"/>	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
<input type="checkbox"/>	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within its portion of the Planning Coordinator's Area.
<input checked="" type="checkbox"/>	Transmission Owner	Owns and maintains transmission facilities.
<input checked="" type="checkbox"/>	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
<input type="checkbox"/>	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within the Transmission Planner Area.
<input type="checkbox"/>	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
<input type="checkbox"/>	Distribution Provider	Delivers electrical energy to the End-use customer.
<input checked="" type="checkbox"/>	Generator Owner	Owns and maintains generation facilities.
<input checked="" type="checkbox"/>	Generator Operator	Operates generation unit(s) to provide real and reactive power.
<input type="checkbox"/>	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
<input type="checkbox"/>	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

**Reliability and Market Interface Principles**

<b>Applicable Reliability Principles</b> <i>(Check box for all that apply.)</i>	
<input checked="" type="checkbox"/>	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
<input type="checkbox"/>	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
<input checked="" type="checkbox"/>	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
<input checked="" type="checkbox"/>	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
<input checked="" type="checkbox"/>	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
<input checked="" type="checkbox"/>	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
<input type="checkbox"/>	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
<input type="checkbox"/>	8. Bulk power systems shall be protected from malicious physical or cyber attacks.
<b>Does the proposed Standard comply with all of the following Market Interface Principles?</b> <i>(Select 'yes' or 'no' from the drop-down box.)</i>	
1. A reliability standard shall not give any market participant an unfair competitive advantage. <b>Yes</b>	
2. A reliability standard shall neither mandate nor prohibit any specific market structure. <b>Yes</b>	
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. <b>Yes</b>	
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. <b>Yes</b>	

**Standards Authorization Request Form**

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***Related Standards***

<b>Standard No.</b>	<b>Explanation</b>

***Related SARs***

<b>SAR ID</b>	<b>Explanation</b>

***Regional Variances***

<b>Region</b>	<b>Explanation</b>
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

## Standard Authorization Request Form

Title of Proposed Standard: Various Standards Containing GO/GOP and TO/TOP Requirements	
Request Date:	January 15, 2010
SC Approval Date:	January 20, 2010

<b>SAR Requester Information</b>	<b>SAR Type</b> ( <i>Check a box for each one that applies.</i> )	
Name: Ad Hoc Group for Generator Requirements at the Transmission Interface	<input type="checkbox"/>	New Standard
Primary Contact: Scott Helyer	<input checked="" type="checkbox"/>	Revision to existing Standards
Telephone: 817-462-1512 Fax:	<input type="checkbox"/>	Withdrawal of existing Standard
E-mail: shelyer@tnsk.com	<input type="checkbox"/>	Urgent Action



## Standards Authorization Request Form

**Purpose** (Describe what the standard action will achieve in support of bulk power system reliability.)

The proposed changes to the requirements and the addition of new requirements will add significant clarity to Generator Owners and Generator Operators regarding their reliability standard obligations at the interface with the interconnected grid.

**Industry Need** (Provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

Significant industry concern exists regarding the application of Transmission Owner and Transmission Operator requirements, and more generally, to the registration of Generator Owners and Generator Operators as Transmission Owners and Transmission Operators, based on the facilities that connect the generators to the interconnected grid. The final report of the Ad Hoc Group for Generator Requirements at the Transmission Interface evaluated the issue and proposes a number of changes that adds much needed clarity on the requirements for Generator Interconnection Facilities. Absent these revisions and additional requirements, Generator Owners and Generator Operators are subject to what some believe to be inappropriate registration as Transmission Owners and Transmission Operators to ensure coverage for certain reliability requirements. The modifications and additions recommended wholly and directly address the requirements for Generator Owners and Generator Operators regarding its Generator Interconnection Facilities, and add particular focus on the operation of the interface point at which operating responsibility shifts from the Generator Operator to the Transmission Operator.

The proposal also modifies certain of NERC's existing glossary terms and adds new terms to support the standards modifications.

**Brief Description** (Provide a paragraph that describes the scope of this standard action.)

32 NERC Reliability Standards contain language regarding generators or generating facilities for which greater clarity regarding its Generator Interconnection Facilities would ensure no reliability gap exists

12 requirements in FAC-003-1 - Transmission Vegetation Management should have their applicability expanded to include Generator Owners.

2 NERC Reliability Standards should have their applicability expanded to include Generator Operators to address general reliability gaps not attributable to their Generator Interconnection Facilities.

8 new Reliability Standard Requirements should be added to ensure the responsibilities for owning and operating the Generator Interconnection Facility are clear, and to address certain requirements that should apply to all generators regardless of interconnection configuration.

New NERC Glossary definitions are needed for Generator Interconnection Facility and Generator Interconnection Operational Interface, as well as modifications to Vegetation Inspection, Right-of-Way, Generator Owner, Generator Operator, and Transmission

**Detailed Description** (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.)

Refer to Final Report of the Ad hoc Group for Generator Requirements at the Transmission Interface.

## Standards Authorization Request Form

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Revisions to the latest versions of the following standards are included in the report and redline standard changes are included to accompany this SAR:

BAL-005

CIP-002

EOP-001, -003, -004, -008

FAC-001, -003, -008, -009

IRO-005

MOD-010, -012

PER-001, -002

PRC-001, -004, -005

TOP-001, -002, -003, -004, -008

VAR-001, -002

**Standards Authorization Request Form**

***Reliability Functions***

<b>The Standard will Apply to the Following Functions</b> <i>(Check box for each one that applies.)</i>		
<input type="checkbox"/>	Reliability Assurer	Monitors and evaluates the activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the bulk power system within a Reliability Assurer Area and adjacent areas.
<input type="checkbox"/>	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
<input type="checkbox"/>	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
<input type="checkbox"/>	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
<input type="checkbox"/>	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
<input type="checkbox"/>	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within its portion of the Planning Coordinator's Area.
<input checked="" type="checkbox"/>	Transmission Owner	Owns and maintains transmission facilities.
<input checked="" type="checkbox"/>	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
<input type="checkbox"/>	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within the Transmission Planner Area.
<input type="checkbox"/>	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
<input type="checkbox"/>	Distribution Provider	Delivers electrical energy to the End-use customer.
<input checked="" type="checkbox"/>	Generator Owner	Owns and maintains generation facilities.
<input checked="" type="checkbox"/>	Generator Operator	Operates generation unit(s) to provide real and reactive power.
<input type="checkbox"/>	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
<input type="checkbox"/>	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

## Standards Authorization Request Form

### **Reliability and Market Interface Principles**

<b>Applicable Reliability Principles</b> <i>(Check box for all that apply.)</i>	
<input checked="" type="checkbox"/>	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
<input type="checkbox"/>	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
<input checked="" type="checkbox"/>	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
<input checked="" type="checkbox"/>	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
<input checked="" type="checkbox"/>	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
<input checked="" type="checkbox"/>	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
<input type="checkbox"/>	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
<input type="checkbox"/>	8. Bulk power systems shall be protected from malicious physical or cyber attacks.
<b>Does the proposed Standard comply with all of the following Market Interface Principles?</b> <i>(Select 'yes' or 'no' from the drop-down box.)</i>	
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes	
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes	
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes	
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes	

**Standards Authorization Request Form**

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***Related Standards***

<b>Standard No.</b>	<b>Explanation</b>

***Related SARs***

<b>SAR ID</b>	<b>Explanation</b>

***Regional Variances***

<b>Region</b>	<b>Explanation</b>
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

## A. Introduction

1. **Title:** Automatic Generation Control

2. **Number:** BAL-005-0.1b

3. **Purpose:**

This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved.

4. **Applicability:**

4.1. Balancing Authorities

4.2. Generator Operators

4.3. Transmission Operators

4.4. Load Serving Entities

5. **Effective Date:** ~~May 13, 2009~~ [TBD](#)

## B. Requirements

**R1.** All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.

**R1.1.** Each Generator Operator with generation facilities, [including its Generator Interconnection Facility](#), operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.

**R1.2.** Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.

**R1.3.** Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a Balancing Authority Area.

**R2.** Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard.

**R3.** A Balancing Authority providing Regulation Service shall ensure that adequate metering, communications, and control equipment are employed to prevent such service from becoming a Burden on the Interconnection or other Balancing Authority Areas.

**R4.** A Balancing Authority providing Regulation Service shall notify the Host Balancing Authority for whom it is controlling if it is unable to provide the service, as well as any Intermediate Balancing Authorities.

**R5.** A Balancing Authority receiving Regulation Service shall ensure that backup plans are in place to provide replacement Regulation Service should the supplying Balancing Authority no longer be able to provide this service.

**R6.** The Balancing Authority's AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority's ACE. Single Balancing Authorities operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control. If a Balancing Authority is unable to calculate ACE for more than 30 minutes it shall notify its Reliability Coordinator.

- R7.** The Balancing Authority shall operate AGC continuously unless such operation adversely impacts the reliability of the Interconnection. If AGC has become inoperative, the Balancing Authority shall use manual control to adjust generation to maintain the Net Scheduled Interchange.
- R8.** The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every six seconds.
- R8.1.** Each Balancing Authority shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of failure of the primary source. This overall installation shall provide a minimum availability of 99.95%.
- R9.** The Balancing Authority shall include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.
- R9.1.** Balancing Authorities with a high voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to their Interconnection may choose to omit the Interchange Schedule related to the HVDC link from the ACE equation if it is modeled as internal generation or load.
- R10.** The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.
- R11.** Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE.
- R12.** Each Balancing Authority shall include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.
- R12.1.** Balancing Authorities that share a tie shall ensure Tie Line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon source using common primary metering equipment. Balancing Authorities shall ensure that megawatt-hour data is telemetered or reported at the end of each hour.
- R12.2.** Balancing Authorities shall ensure the power flow and ACE signals that are utilized for calculating Balancing Authority performance or that are transmitted for Regulation Service are not filtered prior to transmission, except for the Anti-aliasing Filters of Tie Lines.
- R12.3.** Balancing Authorities shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more Balancing Authorities to deliver the output of Jointly Owned Units or to serve remote load.
- R13.** Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the accuracy of its control equipment. The Balancing Authority shall adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error ( $I_{ME}$ ) term of the ACE equation to compensate for any equipment error until repairs can be made.
- R14.** The Balancing Authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, the Balancing Authority shall provide its operating personnel with real-time values for ACE, Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.
- R15.** The Balancing Authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the Balancing Authority's control center and other critical locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.

- R16.** The Balancing Authority shall sample data at least at the same periodicity with which ACE is calculated. The Balancing Authority shall flag missing or bad data for operator display and archival purposes. The Balancing Authority shall collect coincident data to the greatest practical extent, i.e., ACE, Interconnection frequency, Net Actual Interchange, and other data shall all be sampled at the same time.
- R17.** Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy
Digital frequency transducer	$\leq 0.001$ Hz
MW, MVAR, and voltage transducer	$\leq 0.25$ % of full scale
Remote terminal unit	$\leq 0.25$ % of full scale
Potential transformer	$\leq 0.30$ % of full scale
Current transformer	$\leq 0.50$ % of full scale

**C. Measures**

Not specified.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Balancing Authorities shall be prepared to supply data to NERC in the format defined below:

- 1.1.1.** Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization CPS source data in daily CSV files with time stamped one minute averages of: 1) ACE and 2) Frequency Error.
- 1.1.2.** Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization DCS source data in CSV files with time stamped scan rate values for: 1) ACE and 2) Frequency Error for a time period of two minutes prior to thirty minutes after the identified Disturbance.

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

Not specified.

**1.3. Data Retention**

- 1.3.1.** Each Balancing Authority shall retain its ACE, actual frequency, Scheduled Frequency, Net Actual Interchange, Net Scheduled Interchange, Tie Line meter error correction and Frequency Bias Setting data in digital format at the same scan rate at which the data is collected for at least one year.
- 1.3.2.** Each Balancing Authority or Reserve Sharing Group shall retain documentation of the magnitude of each Reportable Disturbance as well as the ACE charts and/or samples used to calculate Balancing Authority or Reserve Sharing Group disturbance recovery values. The data shall be retained for one year following the reporting quarter for which the data was recorded.

**1.4. Additional Compliance Information**

Not specified.



**2. Levels of Non-Compliance**

Not specified.

**E. Regional Differences**

None identified.

**F. Associated Documents**

1. Appendix 1 – Interpretation of Requirement R17 (February 12, 2008).

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0a	December 19, 2007	Added Appendix 1 – Interpretation of R17 approved by BOT on May 2, 2007	Addition
0a	January 16, 2008	Section F: added “1.”; changed hyphen to “en dash.” Changed font style for “Appendix 1” to Arial.	Errata
0b	February 12, 2008	Replaced Appendix 1 – Interpretation of R17 approved by BOT on February 12, 2008.	Replacement
0.1b	October 29, 2008	BOT approved errata changes; updated version number to “0.1b”	Errata
0.1b	May 13, 2009	FERC approved – Updated Effective Date and Footer	Addition
<a href="#">1b</a>	<a href="#">TBD</a>	<a href="#">Modified R1.1 to include its Generator Interconnection Facility</a>	<a href="#">Addition</a>

Appendix 1

**Request:** PGE requests clarification regarding the measuring devices for which the requirement applies, specifically clarification if the requirement applies to the following measuring devices:

- Only equipment within the operations control room
- Only equipment that provides values used to calculate AGC ACE
- Only equipment that provides values to its SCADA system
- Only equipment owned or operated by the BA
- Only to new or replacement equipment
- To all equipment that a BA owns or operates

**BAL-005-1**

**R17.** Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy
Digital frequency transducer	≤ 0.001 Hz
MW, MVAR, and voltage transducer	≤ 0.25% of full scale
Remote terminal unit	≤ 0.25% of full scale
Potential transformer	≤ 0.30% of full scale
Current transformer	≤ 0.50% of full scale

**Existing Interpretation Approved by Board of Trustees May 2, 2007**

BAL-005-0, Requirement 17 requires that the Balancing Authority check and calibrate its control room time error and frequency devices against a common reference at least annually. The requirement to “annually check and calibrate” does not address any devices outside of the operations control room.

The table represents the design accuracy of the listed devices. There is no requirement within the standard to “annually check and calibrate” the devices listed in the table, unless they are included in the control center time error and frequency devices.

**Interpretation:**

As noted in the existing interpretation, BAL-005-1 Requirement 17 applies only to the time error and frequency devices that provide, or in the case of back-up equipment may provide, input into the reporting or compliance ACE equation or provide real-time time error or frequency information to the system operator. Frequency inputs from other sources that are for reference only are excluded. The time error and frequency measurement devices may not necessarily be located in the system operations control room or owned by the Balancing Authority; however the Balancing Authority has the responsibility for the accuracy of the frequency and time error measurement devices. No other devices are included in R 17. The other devices listed in the table at the end of R17 are for reference only and do not have any mandatory calibration or accuracy requirements.

New or replacement equipment that provides the same functions noted above requires the same calibrations. Some devices used for time error and frequency measurement cannot be calibrated as such. In this case, these devices should be cross-checked against other properly calibrated equipment and replaced if the devices do not meet the required level of accuracy.

## A. Introduction

1. **Title:** Cyber Security — Critical Cyber Asset Identification
2. **Number:** CIP-002-~~X1~~
3. **Purpose:** NERC Standards CIP-002 through CIP-009 provide a cyber security framework for the identification and protection of Critical Cyber Assets to support reliable operation of the Bulk Electric System.

These standards recognize the differing roles of each entity in the operation of the Bulk Electric System, the criticality and vulnerability of the assets needed to manage Bulk Electric System reliability, and the risks to which they are exposed. Responsible Entities should interpret and apply Standards CIP-002 through CIP-009 using reasonable business judgment.

Business and operational demands for managing and maintaining a reliable Bulk Electric System increasingly rely on Cyber Assets supporting critical reliability functions and processes to communicate with each other, across functions and organizations, for services and data. This results in increased risks to these Cyber Assets.

Standard CIP-002 requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets that support the reliable operation of the Bulk Electric System. These Critical Assets are to be identified through the application of a risk-based assessment.

4. **Applicability:**
  - 4.1. Within the text of Standard CIP-002, “Responsible Entity” shall mean:
    - 4.1.1 Reliability Coordinator.
    - 4.1.2 Balancing Authority.
    - 4.1.3 Interchange Authority.
    - 4.1.4 Transmission Service Provider.
    - 4.1.5 Transmission Owner.
    - 4.1.6 Transmission Operator.
    - 4.1.7 Generator Owner.
    - 4.1.8 Generator Operator.
    - 4.1.9 Load Serving Entity.
    - 4.1.10 NERC.
    - 4.1.11 Regional Reliability Organizations.
  - 4.2. The following are exempt from Standard CIP-002:
    - 4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
    - 4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
5. **Effective Date:** ~~June 1, 2006~~TBD

## B. Requirements

The Responsible Entity shall comply with the following requirements of Standard CIP-002:

- R1.** Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.
  - R1.1.** The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.
  - R1.2.** The risk-based assessment shall consider the following assets:
    - R1.2.1.** Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.
    - R1.2.2.** Transmission substations that support the reliable operation of the Bulk Electric System.
    - R1.2.3.** Generation resources, [including the Generator Interconnection Facility](#), that support the reliable operation of the Bulk Electric System.
    - R1.2.4.** Systems and facilities critical to system restoration, including blackstart generators [and their attendant Generator Interconnection Facility](#), and substations in the electrical path of transmission lines used for initial system restoration.
    - R1.2.5.** Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.
    - R1.2.6.** Special Protection Systems that support the reliable operation of the Bulk Electric System.
    - R1.2.7.** Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.
- R2.** Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.
- R3.** Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:
  - R3.1.** The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,
  - R3.2.** The Cyber Asset uses a routable protocol within a control center; or,
  - R3.3.** The Cyber Asset is dial-up accessible.
- R4.** Annual Approval — A senior manager or delegate(s) shall approve annually the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of the senior manager or delegate(s)'s

approval of the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)

**C. Measures**

The following measures will be used to demonstrate compliance with the requirements of Standard CIP-002:

- M1.** The risk-based assessment methodology documentation as specified in Requirement R1.
- M2.** The list of Critical Assets as specified in Requirement R2.
- M3.** The list of Critical Cyber Assets as specified in Requirement R3.
- M4.** The records of annual approvals as specified in Requirement R4.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

- 1.1.1** Regional Reliability Organizations for Responsible Entities.
- 1.1.2** NERC for Regional Reliability Organization.
- 1.1.3** Third-party monitor without vested interest in the outcome for NERC.

**1.2. Compliance Monitoring Period and Reset Time Frame**

Annually.

**1.3. Data Retention**

- 1.3.1** The Responsible Entity shall keep documentation required by Standard CIP-002 from the previous full calendar year
- 1.3.2** The compliance monitor shall keep audit records for three calendar years.

**1.4. Additional Compliance Information**

- 1.4.1** Responsible Entities shall demonstrate compliance through self-certification or audit, as determined by the Compliance Monitor.

**2. Levels of Non-Compliance**

- 2.1 Level 1:** The risk assessment has not been performed annually.
- 2.2 Level 2:** The list of Critical Assets or Critical Cyber Assets exist, but has not been approved or reviewed in the last calendar year.
- 2.3 Level 3:** The list of Critical Assets or Critical Cyber Assets does not exist.
- 2.4 Level 4:** The lists of Critical Assets and Critical Cyber Assets do not exist.

**E. Regional Differences**

None identified.

**Version History**

Version	Date	Action	Change Tracking
1	01/16/06	R3.2 — Change “Control Center” to “control center”	03/24/06
<del>X</del>	<del>TBD</del>	<del>Modified R1.2.3 to include the Generator Interconnection Facility and R1.2.4 to</del>	<del>Addition</del>

		<a href="#">include a Generator Interconnection Facility</a>	

## A. Introduction

1. **Title:** **Emergency Operations Planning**
2. **Number:** EOP-001-~~X0~~
3. **Purpose:** Each Transmission Operator and Balancing Authority needs to develop, maintain, and implement a set of plans to mitigate operating emergencies. These plans need to be coordinated with other Transmission Operators and Balancing Authorities, and the Reliability Coordinator.
4. **Applicability**
  - 4.1. Balancing Authorities.
  - 4.2. Transmission Operators.
5. **Effective Date:** ~~April 1, 2005~~TBD

## B. Requirements

- R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.
- R2. The Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission Operator will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes.
- R3. Each Transmission Operator and Balancing Authority shall:
  - R3.1. Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.
  - R3.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.
  - R3.3. Develop, maintain, and implement a set of plans for load shedding.
  - R3.4. Develop, maintain, and implement a set of plans for system restoration.
- R4. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include:
  - R4.1. Communications protocols to be used during emergencies.
  - R4.2. A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions.
  - R4.3. The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.
  - R4.4. Staffing levels for the emergency.
- R5. Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001-0 when developing an emergency plan.

- R6. The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.
- R7. The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable:
  - R7.1. The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.
  - R7.2. The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.
  - R7.3. The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules, [including outages to the Generator Interconnection Facility](#), -to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)
  - R7.4. The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.

#### C. Measures

- M1. The Transmission Operator and Balancing Authority shall have its emergency plans available for review by the Regional Reliability Organization at all times.
- M2. The Transmission Operator and Balancing Authority shall have its two most recent annual self-assessments available for review by the Regional Reliability Organization at all times.

#### D. Compliance

##### 1. Compliance Monitoring Process

###### 1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

###### 1.2. Compliance Monitoring Period and Reset Timeframes

The Regional Reliability Organization shall review and evaluate emergency plans every three years to ensure that the plans consider the applicable elements of Attachment 1-EOP-001-0.

The Regional Reliability Organization may elect to request self-certification of the Transmission Operator and Balancing Authority in years that the full review is not done.

Reset: one calendar year.

###### 1.3. Data Retention

Current plan available at all times.

###### 1.4. Additional Compliance Information

Not specified.

##### 2. Levels of Non-Compliance



## Standard EOP-001-~~X~~<sup>0</sup> — Emergency Operations Planning

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- 2.1. **Level 1:** One of the applicable elements of Attachment 1-EOP-001-~~0~~<sup>X</sup> has not been addressed in the emergency plans.
- 2.2. **Level 2:** Two of the applicable elements of Attachment 1-EOP-001-~~0~~<sup>X</sup> have not been addressed in the emergency plans.
- 2.3. **Level 3:** Three of the applicable elements of Attachment 1-EOP-001-~~X~~<sup>0</sup> have not been addressed in the emergency plans.
- 2.4. **Level 4:** Four or more of the applicable elements of Attachment 1-EOP-001-~~0~~<sup>X</sup> have not been addressed in the emergency plans or a plan does not exist.

### E. Regional Differences

None identified.

### Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
<del>X</del>	<del>TBD</del>	<del>Modified R7.3 to include the Generator Interconnection Facility</del>	<del>Addition</del>

**Attachment 1-EOP-001-0X**

**Elements for Consideration in Development of Emergency Plans**

1. Fuel supply and inventory — An adequate fuel supply and inventory plan that recognizes reasonable delays or problems in the delivery or production of fuel.
2. Fuel switching — Fuel switching plans for units for which fuel supply shortages may occur, e.g., gas and light oil.
3. Environmental constraints — Plans to seek removal of environmental constraints for generating units and plants.
4. System energy use — The reduction of the system's own energy use to a minimum.
5. Public appeals — Appeals to the public through all media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.
6. Load management — Implementation of load management and voltage reductions, if appropriate.
7. Optimize fuel supply — The operation of all generating sources to optimize the availability.
8. Appeals to customers to use alternate fuels — In a fuel emergency, appeals to large industrial and commercial customers to reduce non-essential energy use and maximize the use of customer-owned generation that rely on fuels other than the one in short supply.
9. Interruptible and curtailable loads — Use of interruptible and curtailable customer load to reduce capacity requirements or to conserve the fuel in short supply.
10. Maximizing generator output and availability — The operation of all generating sources to maximize output and availability. This should include plans to winterize units and plants during extreme cold weather.
11. Notifying IPPs — Notification of cogeneration and independent power producers to maximize output and availability.
12. Requests of government — Requests to appropriate government agencies to implement programs to achieve necessary energy reductions.
13. Load curtailment — A mandatory load curtailment plan to use as a last resort. This plan should address the needs of critical loads essential to the health, safety, and welfare of the community. Address firm load curtailment.
14. Notification of government agencies — Notification of appropriate government agencies as the various steps of the emergency plan are implemented.
15. Notifications to operating entities — Notifications to other operating entities as steps in emergency plan are implemented.

## A. Introduction

1. **Title:** Load Shedding Plans
2. **Number:** EOP-003-X1
3. **Purpose:** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.
4. **Applicability**
  - 4.1. Transmission Operators.
  - 4.2. Balancing Authorities.
  - 4.3. Generator Operators.
5. **Effective Date:** ~~January 1, 2007~~ TBD

## B. Requirements

- R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.
- R2. Each Transmission Operator and Balancing Authority shall establish plans for automatic load shedding for underfrequency or undervoltage conditions.
- R3. Each Transmission Operator and Balancing Authority shall coordinate load shedding plans among other interconnected Transmission Operators and Balancing Authorities.
- R4. A Transmission Operator or Balancing Authority shall consider one or more of these factors in designing an automatic load shedding scheme: frequency, rate of frequency decay, voltage level, rate of voltage decay, or power flow levels.
- R5. A Transmission Operator or Balancing Authority shall implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.
- R6. After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.
- R7. The Transmission Operator, Generator Operator, -and Balancing Authority shall coordinate automatic load shedding throughout their areas with underfrequency isolation of generating units, tripping of shunt capacitors, and other automatic actions that will occur under abnormal frequency, voltage, or power flow conditions.
- R8. Each Transmission Operator or Balancing Authority shall have plans for operator-controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.

## C. Measures

- M1.** Each Transmission Operator and Balancing Authority that has or directs the deployment of undervoltage and/or underfrequency load shedding facilities, shall have and provide upon request, its automatic load shedding plans.(Requirement 2)
- M2.** Each Transmission Operator and Balancing Authority shall have and provide upon request its manual load shedding plans that will be used to confirm that it meets Requirement 8. (Part 1)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

#### 1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

#### 1.3. Additional Reporting Requirement

No additional reporting required.

#### 1.4. Data Retention

Each Balancing Authority and Transmission Operator shall have its current, in-force load shedding plans.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

**1.5. 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:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

**2.4.1** Does not have an automatic load shedding plan as specified in R2.

**2.4.2** Does not have manual load shedding plans as specified in R8.

**E. Regional Differences**

None identified.

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
<u>X</u>	<u>TBD</u>	<u>Modified R7 to include Generator Operator.</u> <u>Added Generator Operator to Applicability Section.</u>	<u>Addition</u>

## A. Introduction

1. **Title:** **Disturbance Reporting**
2. **Number:** EOP-004-~~X1~~
3. **Purpose:** Disturbances or unusual occurrences that jeopardize the operation of the Bulk Electric System, or result in system equipment damage or customer interruptions, need to be studied and understood to minimize the likelihood of similar events in the future.
4. **Applicability**
  - 4.1. Reliability Coordinators.
  - 4.2. Balancing Authorities.
  - 4.3. Transmission Operators.
  - 4.4. Generator Operators.
  - 4.5. Load Serving Entities.
  - 4.6. Regional Reliability Organizations.
5. **Effective Date:** ~~January 1, 2007~~[TBD](#)

## B. Requirements

- R1. Each Regional Reliability Organization shall establish and maintain a Regional reporting procedure to facilitate preparation of preliminary and final disturbance reports.
- R2. A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity shall promptly analyze Bulk Electric System disturbances on its system or facilities, [including those for the Generator Interconnection Facility](#).
- R3. A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity experiencing a reportable incident shall provide a preliminary written report to its Regional Reliability Organization and NERC.
  - R3.1. The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity shall submit within 24 hours of the disturbance or unusual occurrence either a copy of the report submitted to DOE, or, if no DOE report is required, a copy of the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report form. Events that are not identified until some time after they occur shall be reported within 24 hours of being recognized.
  - R3.2. Applicable reporting forms are provided in Attachments 1-EOP-004 and 2-EOP-004.
  - R3.3. Under certain adverse conditions, e.g., severe weather, it may not be possible to assess the damage caused by a disturbance and issue a written Interconnection Reliability Operating Limit and Preliminary Disturbance Report within 24 hours. In such cases, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall promptly notify its Regional Reliability Organization(s)

and NERC, and verbally provide as much information as is available at that time. The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall then provide timely, periodic verbal updates until adequate information is available to issue a written Preliminary Disturbance Report.

- R3.4.** If, in the judgment of the Regional Reliability Organization, after consultation with the Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity in which a disturbance occurred, a final report is required, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall prepare this report within 60 days. As a minimum, the final report shall have a discussion of the events and its cause, the conclusions reached, and recommendations to prevent recurrence of this type of event. The report shall be subject to Regional Reliability Organization approval.
- R4.** When a Bulk Electric System disturbance occurs, the Regional Reliability Organization shall make its representatives on the NERC Operating Committee and Disturbance Analysis Working Group available to the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity immediately affected by the disturbance for the purpose of providing any needed assistance in the investigation and to assist in the preparation of a final report.
- R5.** The Regional Reliability Organization shall track and review the status of all final report recommendations at least twice each year to ensure they are being acted upon in a timely manner. If any recommendation has not been acted on within two years, or if Regional Reliability Organization tracking and review indicates at any time that any recommendation is not being acted on with sufficient diligence, the Regional Reliability Organization shall notify the NERC Planning Committee and Operating Committee of the status of the recommendation(s) and the steps the Regional Reliability Organization has taken to accelerate implementation.

### **C. Measures**

- M1.** The Regional Reliability Organization shall have and provide upon request as evidence, its current regional reporting procedure that is used to facilitate preparation of preliminary and final disturbance reports. (Requirement 1)
- M2.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity that has a reportable incident shall have and provide upon request evidence that could include, but is not limited to, the preliminary report, computer printouts, operator logs, or other equivalent evidence that will be used to confirm that it prepared and delivered the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Reports to NERC within 24 hours of its recognition as specified in Requirement 3.1.
- M3.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and/or Load Serving Entity that has a reportable incident shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it provided information verbally

as time permitted, when system conditions precluded the preparation of a report in 24 hours. (Requirement 3.3)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Monitoring Responsibility

NERC shall be responsible for compliance monitoring of the Regional Reliability Organizations.

Regional Reliability Organizations shall be responsible for compliance monitoring of Reliability Coordinators, Balancing Authorities, Transmission Operators, Generator Operators, and Load-serving Entities.

#### 1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

#### 1.3. Data Retention

Each Regional Reliability Organization shall have its current, in-force, regional reporting procedure as evidence of compliance. (Measure 1)

Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and/or Load Serving Entity that is either involved in a Bulk Electric System disturbance or has a reportable incident shall keep data related to the incident for a year from the event or for the duration of any regional investigation, whichever is longer. (Measures 2 through 4)

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,



The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

**1.4. Additional Compliance Information**

See Attachments:

- EOP-004 Disturbance Reporting Form
- Table 1 EOP-004

**2. Levels of Non-Compliance for a Regional Reliability Organization**

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

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

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

**2.4. Level 4:** No current procedure to facilitate preparation of preliminary and final disturbance reports as specified in R1.

**3. Levels of Non-Compliance for a Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load- Serving Entity:**

**3.1. Level 1:** There shall be a level one non-compliance if any of the following conditions exist:

**3.1.1** Failed to prepare and deliver the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Reports to NERC within 24 hours of its recognition as specified in Requirement 3.1

**3.1.2** Failed to provide disturbance information verbally as time permitted, when system conditions precluded the preparation of a report in 24 hours as specified in R3.3

**3.1.3** Failed to prepare a final report within 60 days as specified in R3.4

**3.2. Level 2:** Not applicable.

**3.3. Level 3:** Not applicable

**3.4. Level 4:** Not applicable.

**E. Regional Differences**

None identified.

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	May 23, 2005	Fixed reference to attachments 1-EOP-004-0 and 2-EOP-004-0, Changed chart title 1-FAC-004-0 to 1-EOP-004-0, Fixed title of Table 1 to read 1-EOP-004-0, and fixed font.	Errata
0	July 6, 2005	Fixed email in Attachment 1-EOP-004-0 from <a href="mailto:info@nerc.com">info@nerc.com</a> to <a href="mailto:esisac@nerc.com">esisac@nerc.com</a> .	Errata

**Standard EOP-004-X4 — Disturbance Reporting**

0	July 26, 2005	Fixed Header on page 8 to read EOP-004-0	Errata
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
<u>X</u>	<u>TBD</u>	<u>Modified R2 to include the Generator Interconnection Facility.</u>	<u>Addition</u>

## Attachment 1-EOP-004 NERC Disturbance Report Form

### Introduction

These disturbance reporting requirements apply to all Reliability Coordinators, Balancing Authorities, Transmission Operators, Generator Operators, and Load Serving Entities, and provide a common basis for all NERC disturbance reporting. The entity on whose system a reportable disturbance occurs shall notify NERC and its Regional Reliability Organization of the disturbance using the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report forms. Reports can be sent to NERC via email ([esisac@nerc.com](mailto:esisac@nerc.com)) by facsimile (609-452-9550) using the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report forms. If a disturbance is to be reported to the U.S. Department of Energy also, the responding entity may use the DOE reporting form when reporting to NERC. Note: All Emergency Incident and Disturbance Reports (Schedules 1 and 2) sent to DOE shall be simultaneously sent to NERC, preferably electronically at [esisac@nerc.com](mailto:esisac@nerc.com).

The NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Reports are to be made for any of the following events:

1. The loss of a bulk power transmission component that significantly affects the integrity of interconnected system operations. Generally, a disturbance report will be required if the event results in actions such as:
  - a. Modification of operating procedures.
  - b. Modification of equipment (e.g. control systems or special protection systems) to prevent reoccurrence of the event.
  - c. Identification of valuable lessons learned.
  - d. Identification of non-compliance with NERC standards or policies.
  - e. Identification of a disturbance that is beyond recognized criteria, i.e. three-phase fault with breaker failure, etc.
  - f. Frequency or voltage going below the under-frequency or under-voltage load shed points.
2. The occurrence of an interconnected system separation or system islanding or both.
3. Loss of generation by a Generator Operator, Balancing Authority, or Load-Serving Entity — 2,000 MW or more in the Eastern Interconnection or Western Interconnection and 1,000 MW or more in the ERCOT Interconnection.
4. Equipment failures/system operational actions which result in the loss of firm system demands for more than 15 minutes, as described below:
  - a. Entities with a previous year recorded peak demand of more than 3,000 MW are required to report all such losses of firm demands totaling more than 300 MW.
  - b. All other entities are required to report all such losses of firm demands totaling more than 200 MW or 50% of the total customers being supplied immediately prior to the incident, whichever is less.
5. Firm load shedding of 100 MW or more to maintain the continuity of the bulk electric system.

6. Any action taken by a Generator Operator, Transmission Operator, Balancing Authority, or Load-Serving Entity that results in:
  - a. Sustained voltage excursions equal to or greater than  $\pm 10\%$ , or
  - b. Major damage to power system components, or
  - c. Failure, degradation, or misoperation of system protection, special protection schemes, remedial action schemes, or other operating systems that do not require operator intervention, which did result in, or could have resulted in, a system disturbance as defined by steps 1 through 5 above.
7. An Interconnection Reliability Operating Limit (IROL) violation as required in reliability standard TOP-007.
8. Any event that the Operating Committee requests to be submitted to Disturbance Analysis Working Group (DAWG) for review because of the nature of the disturbance and the insight and lessons the electricity supply and delivery industry could learn.

## NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report

Check here if this is an Interconnection Reliability Operating Limit (IROL) violation report.

1.	Organization filing report.		
2.	Name of person filing report.		
3.	Telephone number.		
4.	Date and time of disturbance. <div style="text-align: right;">Date:(mm/dd/yy) Time/Zone:</div>		
5.	Did the disturbance originate in your system?	Yes <input type="checkbox"/> No <input type="checkbox"/>	
6.	Describe disturbance including: cause, equipment damage, critical services interrupted, system separation, key scheduled and actual flows prior to disturbance and in the case of a disturbance involving a special protection or remedial action scheme, what action is being taken to prevent recurrence.		
7.	Generation tripped. <div style="text-align: right;">MW Total List generation tripped</div>		
8.	Frequency. <div style="text-align: right;">Just prior to disturbance (Hz): Immediately after disturbance (Hz max.): Immediately after disturbance (Hz min.):</div>		
9.	List transmission lines tripped (specify voltage level of each line).		
10.	Demand tripped (MW): Number of affected Customers:	FIRM	INTERRUPTIBLE

	Demand lost (MW-Minutes):		
11.	Restoration time.	INITIAL	FINAL
	Transmission:		
	Generation:		
	Demand:		

## Attachment 2-EOP-004 U.S. Department of Energy Disturbance Reporting Requirements

### Introduction

The U.S. Department of Energy (DOE), under its relevant authorities, has established mandatory reporting requirements for electric emergency incidents and disturbances in the United States. DOE collects this information from the electric power industry on Form EIA-417 to meet its overall national security and Federal Energy Management Agency's Federal Response Plan (FRP) responsibilities. DOE will use the data from this form to obtain current information regarding emergency situations on U.S. electric energy supply systems. DOE's Energy Information Administration (EIA) will use the data for reporting on electric power emergency incidents and disturbances in monthly EIA reports. In addition, the data may be used to develop legislative recommendations, reports to the Congress and as a basis for DOE investigations following severe, prolonged, or repeated electric power reliability problems.

Every Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity must use this form to submit mandatory reports of electric power system incidents or disturbances to the DOE Operations Center, which operates on a 24-hour basis, seven days a week. All other entities operating electric systems have filing responsibilities to provide information to the Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity when necessary for their reporting obligations and to file form EIA-417 in cases where these entities will not be involved. EIA requests that it be notified of those that plan to file jointly and of those electric entities that want to file separately.

Special reporting provisions exist for those electric utilities located within the United States, but for whom Reliability Coordinator oversight responsibilities are handled by electrical systems located across an international border. A foreign utility handling U.S. Balancing Authority responsibilities, may wish to file this information voluntarily to the DOE. Any U.S.-based utility in this international situation needs to inform DOE that these filings will come from a foreign-based electric system or file the required reports themselves.

Form EIA-417 must be submitted to the DOE Operations Center if any one of the following applies (see Table 1-EOP-004-0 — Summary of NERC and DOE Reporting Requirements for Major Electric System Emergencies):

1. Uncontrolled loss of 300 MW or more of firm system load for more than 15 minutes from a single incident.
2. Load shedding of 100 MW or more implemented under emergency operational policy.
3. System-wide voltage reductions of 3 percent or more.
4. Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system.
5. Actual or suspected physical attacks that could impact electric power system adequacy or reliability; or vandalism, which target components of any security system. Actual or suspected cyber or communications attacks that could impact electric power system adequacy or vulnerability.



6. Actual or suspected cyber or communications attacks that could impact electric power system adequacy or vulnerability.
7. Fuel supply emergencies that could impact electric power system adequacy or reliability.
8. Loss of electric service to more than 50,000 customers for one hour or more.
9. Complete operational failure or shut-down of the transmission and/or distribution electrical system.

The initial DOE Emergency Incident and Disturbance Report (form EIA-417 – Schedule 1) shall be submitted to the DOE Operations Center within 60 minutes of the time of the system disruption. Complete information may not be available at the time of the disruption. However, provide as much information as is known or suspected at the time of the initial filing. If the incident is having a critical impact on operations, a telephone notification to the DOE Operations Center (202-586-8100) is acceptable, pending submission of the completed form EIA-417. Electronic submission via an on-line web-based form is the preferred method of notification. However, electronic submission by facsimile or email is acceptable.

An updated form EIA-417 (Schedule 1 and 2) is due within 48 hours of the event to provide complete disruption information. Electronic submission via facsimile or email is the preferred method of notification. Detailed DOE Incident and Disturbance reporting requirements can be found at: <ftp://ftp.eia.doe.gov/pub/electricity/eiafor417.doc>.

<b>Table 1-EOP-004-0</b> <b>Summary of NERC and DOE Reporting Requirements for Major Electric System Emergencies</b>				
<b>Incident No.</b>	<b>Incident</b>	<b>Threshold</b>	<b>Report Required</b>	<b>Time</b>
1	Uncontrolled loss of Firm System Load	≥ 300 MW – 15 minutes or more	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
2	Load Shedding	≥ 100 MW under emergency operational policy	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
3	Voltage Reductions	3% or more – applied system-wide	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
4	Public Appeals	Emergency conditions to reduce demand	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
5	Physical sabotage, terrorism or vandalism	On physical security systems – suspected or real	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
6	Cyber sabotage, terrorism or vandalism	If the attempt is believed to have or did happen	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
7	Fuel supply emergencies	Fuel inventory or hydro storage levels ≤ 50% of normal	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
8	Loss of electric service	≥ 50,000 for 1 hour or more	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
9	Complete operation failure of electrical system	If isolated or interconnected electrical systems suffer total electrical system collapse	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
All DOE EIA-417 Schedule 1 reports are to be filed within 60-minutes after the start of an incident or disturbance All DOE EIA-417 Schedule 2 reports are to be filed within 48-hours after the start of an incident or disturbance				

*All entities required to file a DOE EIA-417 report (Schedule 1 & 2) shall send a copy of these reports to NERC simultaneously, but no later than 24 hours after the start of the incident or disturbance.*

Incident No.	Incident	Threshold	Report Required	Time
1	Loss of major system component	Significantly affects integrity of interconnected system operations	NERC Prelim Final report	24 hour 60 day
2	Interconnected system separation or system islanding	Total system shutdown Partial shutdown, separation, or islanding	NERC Prelim Final report	24 hour 60 day
3	Loss of generation	≥ 2,000 – Eastern Interconnection ≥ 2,000 – Western Interconnection ≥ 1,000 – ERCOT Interconnection	NERC Prelim Final report	24 hour 60 day
4	Loss of firm load ≥15-minutes	Entities with peak demand ≥3,000: loss ≥300 MW All others ≥200MW or 50% of total demand	NERC Prelim Final report	24 hour 60 day
5	Firm load shedding	≥100 MW to maintain continuity of bulk system	NERC Prelim Final report	24 hour 60 day
6	System operation or operation actions resulting in:	<ul style="list-style-type: none"> <li>• Voltage excursions ≥10%</li> <li>• Major damage to system components</li> <li>• Failure, degradation, or misoperation of SPS</li> </ul>	NERC Prelim Final report	24 hour 60 day
7	IROL violation	Reliability standard TOP-007.	NERC Prelim Final report	72 hour 60 day
8	As requested by ORS Chairman	Due to nature of disturbance & usefulness to industry (lessons learned)	NERC Prelim Final report	24 hour 60 day

All NERC Operating Security Limit and Preliminary Disturbance reports will be filed within 24 hours after the start of the incident. If an entity must file a DOE EIA-417 report on an incident, which requires a NERC Preliminary report, the Entity may use the DOE EIA-417 form for both DOE and NERC reports.

*Any entity reporting a DOE or NERC incident or disturbance has the responsibility to also notify its Regional Reliability Organization.*

## A. Introduction

1. **Title:** Plans for Loss of Control Center Functionality
2. **Number:** EOP-008-~~X0~~
3. **Purpose:** Each reliability entity must have a plan to continue reliability operations in the event its control center becomes inoperable.
4. **Applicability**
  - 4.1. Transmission Operators.
  - 4.2. Balancing Authorities.
  - 4.3. Reliability Coordinators.
5. **Effective Date:** ~~April 1, 2005~~TBD

## B. Requirements

- R1. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have a plan to continue reliability operations in the event its control center becomes inoperable. The contingency plan must meet the following requirements:
  - R1.1. The contingency plan shall not rely on data or voice communication from the primary control facility to be viable.
  - R1.2. The plan shall include procedures and responsibilities for providing basic tie line control and procedures and for maintaining the status of all inter-area schedules, such that there is an hourly accounting of all schedules.
  - R1.3. The contingency plan must address monitoring and control of critical transmission facilities, [Generator Interconnection Operational Interface](#), generation control, voltage control, time and frequency control, control of critical substation devices, and logging of significant power system events. The plan shall list the critical facilities.
  - R1.4. The plan shall include procedures and responsibilities for maintaining basic voice communication capabilities with other areas.
  - R1.5. The plan shall include procedures and responsibilities for conducting periodic tests, at least annually, to ensure viability of the plan.
  - R1.6. The plan shall include procedures and responsibilities for providing annual training to ensure that operating personnel are able to implement the contingency plans.
  - R1.7. The plan shall be reviewed and updated annually.
  - R1.8. Interim provisions must be included if it is expected to take more than one hour to implement the contingency plan for loss of primary control facility.

## C. Measures

- M1. Evidence that the Reliability Coordinator, Transmission Operator or Balancing Authority has developed and documented a current contingency plan to continue the monitoring and operation of the electrical equipment under its control to maintain Bulk Electrical System reliability if its primary control facility becomes inoperable.

## D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**

Regional Reliability Organization.

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

Periodic Review: Review and evaluate the plan for loss of primary control facility contingency as part of the three-year on-site audit process. The audit must include a demonstration of the plan by the Reliability Coordinator, Transmission Operator, and Balancing Authority.

Reset: One calendar year.

**1.3. Data Retention**

The contingency plan for loss of primary control facility must be available for review at all times.

**1.4. Additional Compliance Information**

Not specified.

**2. Levels of Non-Compliance**

**2.1. Level 1:** NA

**2.2. Level 2:** A contingency plan has been implemented and tested, but has not been tested in the past year or there are no records of shift operating personnel training.

**2.3. Level 3:** A contingency plan has been implemented, but does not include all of the elements contained in Requirements R1.1–R1.8.

**2.4. Level 4:** A contingency plan has not been developed, implemented, and tested.

**E. Regional Differences**

1. None identified.

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
<del>X</del>	<del>TBD</del>	<del>Modified R1.3 to include Generator Interconnection Operational Interface</del>	<del>Addition</del>

**A. Introduction**

1. **Title:** Facility Connection Requirements
2. **Number:** FAC-001-~~0~~X
3. **Purpose:** To avoid adverse impacts on reliability, Transmission Owners must establish facility connection and performance requirements.
4. **Applicability:**
  - 4.1. Transmission Owner
5. **Effective Date:** ~~April 1, 2005~~TBD

**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, including the Generator Interconnection Facility.
  - R1.2.** Transmission facilities, and
  - R1.3.** End-user facilities
- 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, 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.

**M2.** The Transmission Owner shall make available (to its Compliance Monitor) for inspection evidence that it met all requirements stated in Reliability Standard FAC-001-0\_R2.

**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.

## Standard FAC-001-0~~X~~— Facility Connection Requirements

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- 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
0	April 1, 2005	Effective Date	New
<u>X</u>	<u>TBD</u>	<u>Modified R1.1 to include the Generator Interconnection Facility</u>	<u>Addition</u>



## A. Introduction

1. **Title:** **Transmission Vegetation Management Program**
2. **Number:** FAC-003-~~X1~~
3. **Purpose:** To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation-related outages of the transmission systems to the respective Regional Reliability Organizations (RRO) and the North American Electric Reliability Council (NERC).
4. **Applicability:**
  - 4.1. Transmission Owner.
  - 4.2. Regional Reliability Organization.
  - 4.3. This standard shall apply to all transmission lines operated at 200 kV and above and to any lower voltage lines designated by the RRO as critical to the reliability of the electric system in the region.
  - 4.4. Generator Owner.
  - 4.5. This standard shall apply to the Generator Interconnection Facility above 200 kV that exceed two spans from the generator property line or are otherwise deemed critical by the Regional Entity below 200 kV (subject to the two-span criteria.)
5. **Effective Dates:**
  - ~~5.1. One calendar year from the date of adoption by the NERC Board of Trustees for Requirements 1 and 2.~~
  - ~~5.2.5.1. Sixty calendar days from the date of adoption by the NERC Board of Trustees for Requirements 3 and 4. TBD~~

## B. Requirements

- R1. The Transmission Owner and Generator Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the Transmission Owner's and Generator Owner's objectives, practices, approved procedures, and work specifications<sup>1</sup>.
  - R1.1. The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the Transmission Owner's or Generator Owner's transmission lines.
  - R1.2. The Transmission Owner and Generator Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the Transmission Owner and Generator Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of

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<sup>1</sup> ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.

clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.

**R1.2.1.** Clearance 1 — The Transmission Owner and Generator Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the Transmission Owner or Generator Owner plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.

**R1.2.2.** Clearance 2 — The Transmission Owner and Generator Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These Transmission Owner-specific and Generator Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.

**R1.2.2.1** Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.

**R1.2.2.2** Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.

**R1.3.** All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner or Generator Owner, to perform their duties.

**R1.4.** Each Transmission Owner and Generator Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner or Generator Owner is restricted from attaining the clearances specified in Requirement 1.2.1.

**R1.5.** Each Transmission Owner and Generator Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.

**R2.** The Transmission Owner and Generator Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into

consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each Transmission Owner and Generator Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.

**R3.** The Transmission Owner and Generator Owner shall report quarterly to its RRO, or the RRO's designee, sustained transmission line outages determined by the Transmission Owner or Generator Owner to have been caused by vegetation.

**R3.1.** Multiple sustained 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.

**R3.2.** The Transmission Owner or Generator Owner is not required to report to the RRO, or the RRO's designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the Transmission Owner, Generator Owner, or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).

**R3.3.** The outage information provided by the Transmission Owner or Generator Owner to the RRO, or the RRO's designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the Transmission Owner or Generator Owner.

**R3.4.** An outage shall be categorized as one of the following:

**R3.4.1.** Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;

**R3.4.2.** Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;

**R3.4.3.** Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.

**R4.** The RRO shall report the outage information provided to it by Transmission Owner's, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the RRO as a result of any of the reported outages.

## C. Measures

**M1.** The Transmission Owner has a documented TVMP, as identified in Requirement 1.

**M1.1.** The Transmission Owner has documentation that the Transmission Owner performed the vegetation inspections as identified in Requirement 1.1.

**M1.2.** The Transmission Owner has documentation that describes the clearances identified in Requirement 1.2.

- M1.3.** The Transmission Owner has documentation that the personnel directly involved in the design and implementation of the Transmission Owner's TVMP hold the qualifications identified by the Transmission Owner as required in Requirement 1.3.
- M1.4.** The Transmission Owner has documentation that it has identified any areas not meeting the Transmission Owner's standard for vegetation management and any mitigating measures the Transmission Owner has taken to address these deficiencies as identified in Requirement 1.4.
- M1.5.** The Transmission Owner has a documented process for the immediate communication of imminent threats by vegetation as identified in Requirement 1.5.
- M2.** The Transmission Owner has documentation that the Transmission Owner implemented the work plan identified in Requirement 2.
- M3.** The Transmission Owner has documentation that it has supplied quarterly outage reports to the RRO, or the RRO's designee, as identified in Requirement 3.
- M4.** The RRO has documentation that it provided quarterly outage reports to NERC as identified in Requirement 4.

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Monitoring Responsibility**

RRO  
NERC

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

One calendar Year

#### **1.3. Data Retention**

Five Years

#### **1.4. Additional Compliance Information**

The Transmission Owner shall demonstrate compliance through self-certification submitted to the compliance monitor (RRO) annually that it meets the requirements of NERC Reliability Standard FAC-003-1. The compliance monitor shall conduct an on-site audit every five years or more frequently as deemed appropriate by the compliance monitor to review documentation related to Reliability Standard FAC-003-1. Field audits of ROW vegetation conditions may be conducted if determined to be necessary by the compliance monitor.

### **2. Levels of Non-Compliance**

#### **2.1. Level 1:**

**2.1.1.** The TVMP was incomplete in one of the requirements specified in any subpart of Requirement 1, or;

**2.1.2.** Documentation of the annual work plan, as specified in Requirement 2, was incomplete when presented to the Compliance Monitor during an on-site audit, or;

**2.1.3.** The RRO provided an outage report to NERC that was incomplete and did not contain the information required in Requirement 4.

#### **2.2. Level 2:**

- 2.2.1. The TVMP was incomplete in two of the requirements specified in any subpart of Requirement 1, or;
- 2.2.2. The Transmission Owner was unable to certify during its annual self-certification that it fully implemented its annual work plan, or documented deviations from, as specified in Requirement 2.
- 2.2.3. The Transmission Owner reported one Category 2 transmission vegetation-related outage in a calendar year.

**2.3. Level 3:**

- 2.3.1. The Transmission Owner reported one Category 1 or multiple Category 2 transmission vegetation-related outages in a calendar year, or;
- 2.3.2. The Transmission Owner did not maintain a set of clearances (Clearance 2), as defined in Requirement 1.2.2, to prevent flashover between vegetation and overhead ungrounded supply conductors, or;
- 2.3.3. The TVMP was incomplete in three of the requirements specified in any subpart of Requirement 1.

**2.4. Level 4:**

- 2.4.1. The Transmission Owner reported more than one Category 1 transmission vegetation-related outage in a calendar year, or;
- 2.4.2. The TVMP was incomplete in four or more of the requirements specified in any subpart of Requirement 1.

**E. Regional Differences**

None Identified.

**Version History**

Version	Date	Action	Change Tracking
1	TBA	<ul style="list-style-type: none"> <li>1. Added “Standard Development Roadmap.”</li> <li>2. Changed “60” to “Sixty” in section A, 5.2.</li> <li>3. Added “Proposed Effective Date: April 7, 2006” to footer.</li> <li>4. Added “Draft 3: November 17, 2005” to footer.</li> </ul>	01/20/06
<u>X</u>	<u>TBD</u>	<p><u>Modified the Applicability Section to include the Generator Owner and Generator Interconnection Facility above 200 kV that exceed two spans from the generator property line or are otherwise deemed critical by the Regional Entity below 200 kV (subject to the two-span criteria.).</u></p> <p><u>Included Generator Owner into the following Requirements: R1, R1.1, R1.2, R1.2.1, R1.2.2, R1.3, R1.4, R1.5, R2, R3,</u></p>	<u>Addition</u>

Standard FAC-003-X4 — Transmission Vegetation Management Program

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		<a href="#">R3.2, and R3.3</a>	

## A. Introduction

1. **Title:** Facility Ratings Methodology
2. **Number:** FAC-008-4X
3. **Purpose:** To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
  - 4.1. Transmission Owner
  - 4.2. Generator Owner
5. **Effective Date:** ~~August 7, 2006~~TBD

## B. Requirements

- R1. The Transmission Owner and Generator Owner shall each document its current methodology used for developing Facility Ratings (Facility Ratings Methodology) of its solely and jointly owned Facilities, including the Generator Interconnection Facility. The methodology shall include all of the following:
  - R1.1. A statement that a Facility Rating shall equal the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.
  - R1.2. The method by which the Rating (of major BES equipment that comprises a Facility) is determined.
    - R1.2.1. The scope of equipment addressed shall include, but not be limited to, generators, the Generator Interconnection Facility, transmission conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.
    - R1.2.2. The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.
  - R1.3. Consideration of the following:
    - R1.3.1. Ratings provided by equipment manufacturers.
    - R1.3.2. Design criteria (e.g., including applicable references to industry Rating practices such as manufacturer's warranty, IEEE, ANSI or other standards).
    - R1.3.3. Ambient conditions.
    - R1.3.4. Operating limitations.
    - R1.3.5. Other assumptions.
- R2. The Transmission Owner and Generator Owner shall each make its Facility Ratings Methodology available for inspection and technical review by those Reliability Coordinators, Transmission Operators, Transmission Planners, and Planning Authorities that have responsibility for the area in which the associated Facilities are located, within 15 business days of receipt of a request.
- R3. If a Reliability Coordinator, Transmission Operator, Transmission Planner, or Planning Authority provides written comments on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings Methodology, the Transmission Owner or Generator Owner shall provide a written response to that commenting entity within 45 calendar days of



receipt of those comments. The response shall indicate whether a change will be made to the Facility Ratings Methodology and, if no change will be made to that Facility Ratings Methodology, the reason why.

### C. Measures

- M1.** The Transmission Owner and Generator Owner shall each have a documented Facility Ratings Methodology that includes all of the items identified in FAC-008 Requirement 1.1 through FAC-008 Requirement 1.3.5.
- M2.** The Transmission Owner and Generator Owner shall each have evidence it made its Facility Ratings Methodology available for inspection within 15 business days of a request as follows:
  - M2.1** The Reliability Coordinator shall have access to the Facility Ratings Methodologies used for Rating Facilities in its Reliability Coordinator Area.
  - M2.2** The Transmission Operator shall have access to the Facility Ratings Methodologies used for Rating Facilities in its portion of the Reliability Coordinator Area.
  - M2.3** The Transmission Planner shall have access to the Facility Ratings Methodologies used for Rating Facilities in its Transmission Planning Area.
  - M2.4** The Planning Authority shall have access to the Facility Ratings Methodologies used for Rating Facilities in its Planning Authority Area.
- M3.** If the Reliability Coordinator, Transmission Operator, Transmission Planner, or Planning Authority provides documented comments on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings Methodology, the Transmission Owner or Generator Owner shall have evidence that it provided a written response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Facility Ratings Methodology and, if no change will be made to that Facility Ratings Methodology, the reason why.

### D. Compliance

#### 1. Compliance Monitoring Process

##### 1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

##### 1.2. Compliance Monitoring Period and Reset Time Frame

Each Transmission Owner and Generator Owner shall self-certify its compliance to the Compliance Monitor at least once every three years. New Transmission Owners and Generator Owners shall each demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

##### 1.3. Data Retention

The Transmission Owner and Generator Owner shall each keep all superseded portions of its Facility Ratings Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on the Facility Ratings Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.



The Compliance Monitor shall keep the last audit and all subsequent compliance records.

**1.4. Additional Compliance Information**

The Transmission Owner and Generator Owner shall each make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

- 1.4.1 Facility Ratings Methodology
- 1.4.2 Superseded portions of its Facility Ratings Methodology that had been replaced, changed or revised within the past 12 months
- 1.4.3 Documented comments provided by a Reliability Coordinator, Transmission Operator, Transmission Planner or Planning Authority on its technical review of a Transmission Owner’s or Generator Owner’s Facility Ratings methodology, and the associated responses

**2. Levels of Non-Compliance**

**2.1. Level 1:** There shall be a level one non-compliance if any of the following conditions exists:

- 2.1.1 The Facility Ratings Methodology does not contain a statement that a Facility Rating shall equal the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.
- 2.1.2 The Facility Ratings Methodology does not address one of the required equipment types identified in FAC-008 R1.2.1.
- 2.1.3 No evidence of responses to a Reliability Coordinator’s, Transmission Operator, Transmission Planner, or Planning Authority’s comments on the Facility Ratings Methodology.

**2.2. Level 2:** The Facility Ratings Methodology is missing the assumptions used to determine Facility Ratings or does not address two of the required equipment types identified in FAC-008 R1.2.1.

**2.3. Level 3:** The Facility Ratings Methodology does not address three of the required equipment types identified in FAC-008-1 R1.2.1.

**2.4. Level 4:** The Facility Ratings Methodology does not address both Normal and Emergency Ratings or the Facility Ratings Methodology was not made available for inspection within 15 business days of receipt of a request.

**E. Regional Differences**

None Identified.

**Version History**

Version	Date	Action	Change Tracking
1	01/01/05	1. Lower cased the word “draft” and “drafting team” where appropriate. 2. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 3. Changed “Timeframe” to “Time	01/20/05

Standard FAC-008-4X — Facility Ratings Methodology

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		Frame” and “twelve” to “12” in item D, 1.2.	
<u>X</u>	<u>TBD</u>	<u>Modified R1 and R1.2.1 to include the Generator Interconnection Facility</u>	<u>Addition</u>

## A. Introduction

1. **Title:** Establish and Communicate Facility Ratings
2. **Number:** FAC-009-X1
3. **Purpose:** To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
  - 4.1. Transmission Owner
  - 4.2. Generator Owner
5. **Effective Date:** ~~October 7, 2006~~TBD

## B. Requirements

- R1. The Transmission Owner and Generator Owner shall each establish Facility Ratings for its solely and jointly owned Facilities, including the Generator Interconnection Facility, that are consistent with the associated Facility Ratings Methodology.
- R2. The Transmission Owner and Generator Owner shall each provide Facility Ratings for its solely and jointly owned Facilities, including the Generator Interconnection Facility, that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities to its associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) as scheduled by such requesting entities.

## C. Measures

- M1. The Transmission Owner and Generator Owner shall each be able to demonstrate that it developed its Facility Ratings consistent with its Facility Ratings Methodology.
  - M1.1 The Transmission Owner's and Generator Owner's Facility Ratings shall each include ratings for its solely and jointly owned Facilities including new Facilities, existing Facilities, modifications to existing Facilities and re-ratings of existing Facilities.
- M2. The Transmission Owner and Generator Owner shall each have evidence that it provided its Facility Ratings to its associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) as scheduled by such requesting entities.

## D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**

Regional Reliability Organization
  - 1.2. **Compliance Monitoring Period and Reset Time Frame**

Each Transmission Owner and Generator Owner shall self-certify its compliance to the Compliance Monitor annually. The Compliance Monitor may conduct a targeted audit once in each calendar year (January–December) and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last finding of non-compliance.

**1.3. Data Retention**

The Transmission Owner and Generator Owner shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall retain audit data for three years.

**1.4. Additional Compliance Information**

The Transmission Owner and Generator Owner shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

- 1.4.1 Facility Ratings Methodology
- 1.4.2 Facility Ratings
- 1.4.3 Evidence that Facility Ratings were distributed
- 1.4.4 Distribution schedules provided by entities that requested Facility Ratings

**2. Levels of Non-Compliance**

- 2.1. **Level 1:** Not all requested Facility Ratings associated with existing Facilities were provided to the Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) in accordance with their respective schedules.
- 2.2. **Level 2:** Not all Facility Ratings associated with new Facilities, modifications to existing Facilities, and re-ratings of existing Facilities were provided to the Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) in accordance with their respective schedules.
- 2.3. **Level 3:** Facility Ratings provided were not developed consistent with the Facility Ratings Methodology.
- 2.4. **Level 4:** No Facility Ratings were provided to the Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), or Transmission Operator(s) in accordance with their respective schedules.

**E. Regional Differences**

None Identified.

**Version History**

Version	Date	Action	Change Tracking
1	08/01/05	1. Lower cased the word “draft” and “drafting team” where appropriate. 2. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 3. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
<u>X</u>	<u>TBD</u>	<u>Modified R1 and R2 to include the Generator Interconnection Facility</u>	<u>Addition</u>

## A. Introduction

1. **Title:** Reliability Coordination — Current Day Operations
2. **Number:** IRO-005-~~X2~~
3. **Purpose:** The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.
4. **Applicability**
  - 4.1. Reliability Coordinators.
  - 4.2. Balancing Authorities.
  - 4.3. Transmission Operators.
  - 4.4. Transmission Service Providers.
  - 4.5. Generator Operators.
  - 4.6. Load-Serving Entities.
  - 4.7. Purchasing-Selling Entities.
5. **Effective Date:** ~~January 1, 2007~~TBD

## B. Requirements

- R1. Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:
  - R1.1. Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading.
  - R1.2. Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.
  - R1.3. Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.
  - R1.4. System real and reactive reserves (actual versus required).
  - R1.5. Capacity and energy adequacy conditions.
  - R1.6. Current ACE for all its Balancing Authorities.
  - R1.7. Current local or Transmission Loading Relief procedures in effect.
  - R1.8. Planned generation dispatches.
  - R1.9. Planned transmission or generation outages.
  - R1.10. Contingency events.
- R2. Each Reliability Coordinator shall be aware of all Interchange Transactions that wheel through, source, or sink in its Reliability Coordinator Area, and make that Interchange Transaction information available to all Reliability Coordinators in the Interconnection.

- R3.** As portions of the transmission system approach or exceed SOLs or IROLs, the Reliability Coordinator shall work with its Transmission Operators and Balancing Authorities to evaluate and assess any additional Interchange Schedules that would violate those limits. If a potential or actual IROL violation cannot be avoided through proactive intervention, the Reliability Coordinator shall initiate control actions or emergency procedures to relieve the violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall ensure all resources, including load shedding, are available to address a potential or actual IROL violation.
- R4.** Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.
- R5.** Each Reliability Coordinator shall identify the cause of any potential or actual SOL or IROL violations. The Reliability Coordinator shall initiate the control action or emergency procedure to relieve the potential or actual IROL violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall be able to utilize all resources, including load shedding, to address an IROL violation.
- R6.** Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.
- R7.** The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.
- R8.** Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.
- R9.** The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages, [including the Generator Interconnection Facility](#), with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.
- R10.** As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities.
- R11.** The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.
- R12.** Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of

the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.

R13. The Generator Operator shall immediately inform the Transmission Operator of the status of the Special Protection System, including any degradation or potential failure to operate as expected for SPS relay or control equipment under its control.

R13.R14. Each Reliability Coordinator shall ensure that all Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities operate to prevent the likelihood that a disturbance, action, or non-action in its Reliability Coordinator Area will result in a SOL or IROL violation in another area of the Interconnection. In instances where there is a difference in derived limits, the Reliability Coordinator and its Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.

R14.R15. Each Reliability Coordinator shall make known to Transmission Service Providers within its Reliability Coordinator Area, SOLs or IROLs within its wide-area view. The Transmission Service Providers shall respect these SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.

R15.R16. Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.

R16.R17. Each Reliability Coordinator shall confirm reliability assessment results and determine the effects within its own and adjacent Reliability Coordinator Areas. The Reliability Coordinator shall discuss options to mitigate potential or actual SOL or IROL violations and take actions as necessary to always act in the best interests of the Interconnection at all times.

R17.R18. When an IROL or SOL is exceeded, the Reliability Coordinator shall evaluate the local and wide-area impacts, both real-time and post-contingency, and determine if the actions being taken are appropriate and sufficient to return the system to within IROL in thirty minutes. If the actions being taken are not appropriate or sufficient, the Reliability Coordinator shall direct the Transmission Operator, Balancing Authority, Generator Operator, or Load-Serving Entity to return the system to within IROL or SOL.

### C. Measures

**M1.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, a prepared report specifically detailing compliance to each of the bullets in Requirement 1, EMS availability, SCADA data collection system communications performance or equivalent evidence that will be used to confirm that it monitors the Reliability Coordinator Area parameters specified in Requirements 1.1 through 1.9.

**M2.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Historical Tag Archive information, Interchange Transaction records,



computer printouts, voice recordings or transcripts of voice recordings or equivalent evidence that will be used to confirm that it was aware of and made Interchange Transaction information available to all other Reliability Coordinators, as specified in Requirement 2.

- M3.** If a potential or actual IROL violation occurs, the Reliability Coordinator involved in the event shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, system event logs, operator action notes or equivalent evidence that will be used to determine if it initiated control actions or emergency procedures to relieve that IROL violation within 30 minutes. (Requirement 3 Part 2 and Requirement 5)
- M4.** If one of its Balancing Authorities has insufficient operating reserves, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to computer printouts, operating logs, voice recordings or transcripts of voice recordings, or equivalent evidence that will be used to determine if the Reliability Coordinator directed and, if needed, assisted the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. (Requirement 4 Part 2 and Requirement 10)
- M5.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to determine if it informed Transmission Operators and Balancing Authorities of Geo-Magnetic Disturbance (GMD) forecast information and provided assistance as needed in the development of any required response plans. (Requirement 6)
- M6.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it disseminated information within its Reliability Coordinator Area in accordance with Requirement 7.
- M7.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, computer printouts, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it monitored system frequency and Balancing Authority performance and directed any necessary rebalancing, as specified in Requirement 8 Part 1.
- M8.** The Transmission Operators and Balancing Authorities shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it utilized all resources, including firm load shedding, as directed by its Reliability Coordinator, to relieve an emergent condition. (Requirement 8 Part 2)
- M9.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, operator logs or equivalent evidence that will be used to determine if it coordinated with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations including the coordination of pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities and Generator Operators. (Requirement 9 Part 1)
- M10.** If a large Area Control Error has occurred, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings



or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it identified sources of the Area Control Errors, and initiated corrective actions with the appropriate Balancing Authority if the problem was within the Reliability Coordinator's Area (Requirement 11 Part 1)

- M11.** If a Special Protection System is armed and that system could have had an inter-area impact, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, agreements with their Transmission Operators, procedural documents, operator logs, computer analysis, training modules, training records or equivalent evidence that will be used to confirm that it was aware of the impact of that Special Protection System on inter-area flows. (Requirement 12)
- M12.** If there is an instance where there is a disagreement on a derived limit, the Reliability Coordinator, Transmission Operator, Balancing Authority, Generator Operator, Load-serving Entity, Purchasing-selling Entity and Transmission Service Provider involved in the disagreement shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications or equivalent evidence that will be used to determine if it operated to the most limiting parameter. (Part 2 of Requirement 13)
- M13.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, procedural documents, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it provided SOL and IROL information to Transmission Service Providers within its Reliability Coordinator Area. (Requirement 14, Part 1)
- M14.** The Transmission Service Providers shall have and provide upon request evidence that could include, but is not limited to, procedural documents, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it respected the SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.(Requirement 14 Part 2)
- M15.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it issued alerts when it foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area, to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area as specified in Requirement 15 Part 1.
- M16.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that upon receiving information such as an SOL or IROL violation, loss of reactive reserves, etc. it disseminated the information to its impacted Transmission Operators and Balancing Authorities as specified in Requirement 15 Part 2.
- M17.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it notified all impacted Transmission Operators, Balancing Authorities and Reliability Coordinators when a transmission problem has been mitigated. (Requirement 15 Part 3)

## D. Compliance

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Regional Reliability Organizations shall be responsible for compliance monitoring.

**1.2. Compliance Monitoring and Reset Time Frame**

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

**1.3. Data Retention**

For Measures 1 and 11, each Reliability Coordinator shall have its current in-force documents as evidence.

For Measures 2–10 and Measure 13, and Measures 15 through 16, the Reliability Coordinator shall keep 90 days of historical data (evidence).

For Measure 8, the Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence).

For Measure 12, the Reliability Coordinator, Transmission Operator, Balancing Authority, and Transmission Service Provider shall keep 90 days of historical data (evidence).

For Measure 14, the Transmission Service Provider shall keep 90 days of historical data (evidence).

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

**1.4. Additional Compliance Information**

None.

2. **Levels of Non-Compliance for a Transmission Operator, Balancing Authority, Generator Operator, Load-serving Entity, Purchasing-selling Entity and Transmission Service Provider**
  - 2.1. **Level 1:** Not applicable.
  - 2.2. **Level 2:** Not applicable.
  - 2.3. **Level 3:** Not applicable.
  - 2.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:
    - 2.4.1 Did not follow the Reliability Coordinator's directives in accordance with R8 Part 2).
    - 2.4.2 Did not operate to the most limiting parameter when a difference in derived limits existed. (R13 Part 2)
3. **Levels of Non-Compliance for a Reliability Coordinator:**
  - 3.1. **Level 1:** Not applicable.
  - 3.2. **Level 2:** Did not make Interchange Transaction information available to all other Reliability Coordinators in the Interconnection. (Requirement 2)
  - 3.3. **Level 3:** There shall be a separate Level 3 non-compliance, for every one of the following requirements that is in violation:
    - 3.3.1 Did not communicate to each of its Balancing Authorities and Transmission Operators to make them aware of GMD forecast information or did not assist in the development of any required response plans to a predicted GMD. (Requirement 6)
    - 3.3.2 Did not disseminate information within its Reliability Coordinator Area. (Requirement 7)
  - 3.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:
    - 3.4.1 Does not meet one or more of the requirements as specified in requirement 1 (Requirements 1.1 through R1.9)
    - 3.4.2 Did not make Interchange Transaction information available to all other Reliability Coordinators. (Requirement 2)
    - 3.4.3 Did not initiate control actions or emergency procedures to relieve an IROL violation without delay, and no longer than 30 minutes. (Requirement 3 Part 2 and Requirement 5)
    - 3.4.4 Did not direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. (Requirement 4 Part 2)
    - 3.4.5 Did not monitor the system frequency or each of its Balancing Authorities performance or did not direct rebalancing to return to DCS and CPS compliance. (Requirement 8 Part 1)
    - 3.4.6 Did not coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations. (Requirement 9)

- 3.4.7 When it identified a source of large Area Control Errors, it did not initiate corrective actions with the appropriate Balancing Authority if the problem was inside its Reliability Coordinator Area. (Requirement 11 part 1)
- 3.4.8 Did not provide evidence that it was aware of the impact of the operation of a Special Protection System on inter-area flows. (Requirement 12)
- 3.4.9 Did not operate to the most limiting parameter when a difference in derived limits existed. (Requirement 13 Part 2)
- 3.4.10 Did not provide Transmission Service Providers with SOLs or IROLs (within the Reliability Coordinator’s wide-area view ) (Requirement 14 Part 1)
- 3.4.11 Did not issue alerts when it foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area. (Requirement 15)

**4. Levels of Non-Compliance for a Transmission Service Provider**

- 4.1. **Level 1:** Not applicable.
- 4.2. **Level 2:** Not applicable.
- 4.3. **Level 3:** Not applicable.
- 4.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:
  - 4.4.1 Did not operate to the most limiting parameter when a difference in derived limits existed. (R13 Part 2)
  - 4.4.2 Did not respect the SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.(Requirement 14 Part 2)

**E. Regional Differences**

None identified.

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	February 2, 2006	Approved by Board of Trustees	Revised
2	August 31, 2006	Added three items that were inadvertently left out to “Applicability” section: 4.5 Generator Operators. 4.6 Load-Serving Entities. 4.7 Purchasing-Selling Entities	Errata
2	November 1, 2006	Approved by Board of Trustees	Revised
2	June 26, 2007	Approved by FERC:	Revised

Standard IRO-005-~~X~~<sup>2</sup> — Reliability Coordination — Current Day Operations

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		Missing Measures and Compliance Elements	
<u>X</u>	<u>TBD</u>	<u>Modified R9 to include the Generator Interconnection Facility.</u> <u>Added a new Requirement R13</u>	<u>Addition</u>

## A. Introduction

1. **Title:** Steady-State Data for Modeling and Simulation of the Interconnected Transmission System
2. **Number:** MOD-010-~~X0~~
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. **Effective Date:** ~~April 1, 2005~~TBD

## B. Requirements

- R1. The Transmission Owners, Transmission Planners Generator Owners ([for plant and Generator Interconnection Facility](#)), and Resource Planners -(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 Schedules in compliance with its respective Interconnection Regional steady-state modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-011-0\_R1.
- R2. The Transmission Owners, Transmission Planners, Generator Owners ([for plant and Generator Interconnection Facility](#)), and Resource Planners -(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 specified within Reliability Standard MOD-011-0\_R1. If no schedule exists, then these entities shall provide the data on request (30 calendar days).

## C. Measures

- M1. The Transmission Owner, Transmission Planner, Generator Owner, and Resource Planner, (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 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**

~~+~~None identified.

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
<u>X</u>	<u>TBD</u>	<u>Modified R1 and R2 to include plant and Generator Interconnection Facility</u>	<u>Addition</u>

## A. Introduction

1. **Title:** Dynamics Data for Modeling and Simulation of the Interconnected Transmission System.
2. **Number:** MOD-012-~~X0~~
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\_R1
  - 4.2. Transmission Planners specified in the data requirements and reporting procedures of MOD-013-0\_R1
  - 4.3. Generator Owners specified in the data requirements and reporting procedures of MOD-013-0\_R1
  - 4.4. Resource Planners specified in the data requirements and reporting procedures of MOD-013-0\_R1
5. **Effective Date:** ~~April 1, 2005~~TBD

## B. Requirements

- R1. The Transmission Owners, Transmission Planners, Generator Owners ([for plant and Generator Interconnection Facility](#)), and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0\_R1) shall provide appropriate equipment characteristics and system data in compliance with the respective Interconnection-wide Regional dynamics system modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-013-0\_R1.
- R2. The Transmission Owners, Transmission Planners, Generator Owners ([for plant and Generator Interconnection Facility](#)), and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0\_R1) shall provide dynamics system modeling and simulation data to its Regional Reliability Organization(s), NERC, and those entities specified within the applicable reporting procedures identified in Reliability Standard MOD-013-0\_R1. If no schedule exists, then these entities 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\_R1) 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\_R1.

**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\_R1.

**2.4. Level 4:** Dynamics data was not provided.

**E. Regional Differences**

1. None identified.

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	September 16, 2005	Changed references to MOD-013-0 R4 to MOD-013-0 R1 in Applicability, Requirements, and Measures (4 in all).	Errata
<del>X</del>	<del>TBD</del>	<del>Modified R1 and R2 to include plant and Generator Interconnection Facility</del>	<del>Addition</del>

## A. Introduction

1. **Title:** **Operating Personnel Responsibility and Authority**
2. **Number:** PER-001-~~X0~~
3. **Purpose:** Transmission Operator and Balancing Authority operating personnel must have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.
4. **Applicability**
  - 4.1. Transmission Operators.
  - 4.2. Balancing Authorities.
  - 4.3. Generator Operators.
5. **Effective Date:** ~~April 1, 2005~~TBD

## B. Requirements

- R1. Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.
- R2. Each Generator Operator shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Generation Facility and Generation Interconnection Facility, and the responsibility and authority to follow the directives of reliability authorities including the Transmission Operator and Balancing Authority.

## C. Measures

- M1. The Transmission Operator and Balancing Authority provide documentation that operating personnel have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System. These responsibilities and authorities are understood by the operating personnel. Documentation shall include:
  - M1.1 A written current job description that states in clear and unambiguous language the responsibilities and authorities of each operating position of a Transmission Operator and Balancing Authority. The position description identifies personnel subject to the authority of the Transmission Operator and Balancing Authority.
  - M1.2 The current job description is readily accessible in the control room environment to all operating personnel.
  - M1.3 A written current job description that states operating personnel are responsible for complying with the NERC reliability standards.
  - M1.4 Written operating procedures that state that, during normal and emergency conditions, operating personnel have the authority to take or direct timely and appropriate real-time actions. Such actions shall include shedding of firm load to prevent or alleviate System Operating Limit Interconnection or Reliability Operating Limit violations. These actions are performed without obtaining approval from higher-level personnel within the Transmission Operator or Balancing Authority.

## D. Compliance

1. **Compliance Monitoring Process**

Periodic Review: An on-site review including interviews with Transmission Operator and Balancing Authority operating personnel and document verification will be conducted every three years. The job description identifying operating personnel authorities and responsibilities will be reviewed, as will the written operating procedures or other documents delineating the authority of the operating personnel to take actions necessary to maintain the reliability of the Bulk Electric System during normal and emergency conditions.

**1.1. Compliance Monitoring Responsibility**

Self-certification: The Transmission Operator and Balancing Authority shall annually complete a self-certification form developed by the Regional Reliability Organization based on measures M1.1 to M1.4.

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

One calendar year.

**1.3. Data Retention**

Permanent.

**1.4. Additional Compliance Information**

**2. Levels of Non-Compliance**

- 2.1. Level 1:** The Transmission Operator or Balancing Authority has written documentation that includes three of the four items in M1.
- 2.2. Level 2:** The Transmission Operator or Balancing Authority has written documentation that includes two of the four items in M1.
- 2.3. Level 3:** The Transmission Operator or Balancing Authority has written documentation that includes one of the four items in M1.
- 2.4. Level 4:** The Transmission Operator or Balancing Authority has written documentation that includes none of the items in M1, or the personnel interviews indicate Transmission Operator or Balancing Authority do not have the required authority.

**E. Regional Differences**

None identified.

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
<a href="#">X</a>	<a href="#">TBD</a>	<a href="#">Added new Requirement R2</a> <a href="#">Added Generator Operators to the Applicability Section</a>	<a href="#">Addition</a>

## A. Introduction

1. **Title:** Operating Personnel Training
2. **Number:** PER-002-~~X0~~
3. **Purpose:** Each Transmission Operator and Balancing Authority must provide their personnel with a coordinated training program that will ensure reliable system operation.
4. **Applicability**
  - 4.1. Balancing Authority.
  - 4.2. Transmission Operator.
  - 4.3. Generator Operator.
5. **Effective Date:** ~~April 1, 2005~~TBD

## B. Requirements

- R1. Each Transmission Operator, Generator Operator, and Balancing Authority shall be staffed with adequately trained operating personnel.
- R2. Each Transmission Operator and Balancing Authority shall have a training program for all operating personnel that are in:
  - R2.1. Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System.
  - R2.2. Positions directly responsible for complying with NERC standards.
- R3. Each Generator Operator shall implement an initial and continuing training program for all operating personnel that are responsible for operating the Generator Interconnection Facility that verifies the personnel's ability and understanding to operate the equipment in a reliable manner.
- ~~R3~~R4. \_\_\_\_\_ For personnel identified in Requirement R2, the Transmission Operator and Balancing Authority shall provide a training program meeting the following criteria:
  - ~~R3.1~~R4.1. \_\_\_\_\_ A set of training program objectives must be defined, based on NERC and Regional Reliability Organization standards, entity operating procedures, and applicable regulatory requirements. These objectives shall reference the knowledge and competencies needed to apply those standards, procedures, and requirements to normal, emergency, and restoration conditions for the Transmission Operator and Balancing Authority operating positions.
  - ~~R3.2~~R4.2. \_\_\_\_\_ The training program must include a plan for the initial and continuing training of Transmission Operator and Balancing Authority operating personnel. That plan shall address knowledge and competencies required for reliable system operations.
  - ~~R3.3~~R4.3. \_\_\_\_\_ The training program must include training time for all Transmission Operator and Balancing Authority operating personnel to ensure their operating proficiency.
  - ~~R3.4~~R4.4. \_\_\_\_\_ Training staff must be identified, and the staff must be competent in both knowledge of system operations and instructional capabilities.
- ~~R4~~R5. \_\_\_\_\_ For personnel identified in Requirement R2, each Transmission Operator and Balancing Authority shall provide its operating personnel at least five days per year of training

and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.

**C. Measures**

- M1. The Transmission Operator and Balancing Authority operating personnel training program shall be reviewed to ensure that it is designed to promote reliable system operations.

**D. Compliance**

**1. Compliance Monitoring Process**

Periodic Review: The Regional Reliability Organization will conduct an on-site review of the Transmission Operator and Balancing Authority operating personnel training program every three years. The operating personnel training records will be reviewed and assessed compared to the program curriculum.

**1.1. Compliance Monitoring Responsibility**

Self-certification: The Transmission Operator and Balancing Authority will annually provide a self-certification based on Requirements R1 through R4.

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

One calendar year.

**1.3. Data Retention**

Three years.

**1.4. Additional Compliance Information**

Not specified.

**2. Levels of Non-Compliance**

**2.1. Level 1:** N/A.

**2.2. Level 2:** The Transmission Operator or Balancing Authority operating personnel training program does not address all elements of Requirement R3.

**2.3. Level 3:** The Transmission Operator or Balancing Authority operating personnel training program does not address Requirement R4.

**2.4. Level 4:** A Transmission Operator or Balancing Authority has not provided a training program for its operating personnel.

**E. Regional Differences**

None identified.

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Proposed Effective Date	Errata
<u>X</u>	<u>TBD</u>	<u>Modified R1 and the Applicability Section to include Generator Operator</u> <u>Added new Requirement R3</u>	<u>Addition</u>

Standard PER-002-~~X0~~ — Operating Personnel Training

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## A. Introduction

1. **Title:** System Protection Coordination

2. **Number:** PRC-001-~~X1~~

3. **Purpose:**

To ensure system protection is coordinated among operating entities.

4. **Applicability**

4.1. Balancing Authorities

4.2. Transmission Operators

4.3. Generator Operators

5. **Effective Date:** ~~January 1, 2007~~TBD

## B. Requirements

**R1.** Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area, [including those for the Generator Interconnection Facility](#).

**R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures, [including those for the Generator Interconnection Facility](#), as follows:

**R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.

**R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

**R3.** A Generator Operator or Transmission Operator shall coordinate new protective systems and changes, [including those for the Generator Interconnection Facility](#), as follows.

**R3.1.** Each Generator Operator shall coordinate all new protective systems and all protective system changes, [including those for the Generator Interconnection Facility](#), with its Transmission Operator and Host Balancing Authority.

**R3.2.** Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.

**R4.** Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.

- R5.** A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions, [including those for the Generator Interconnection Facility](#), that could require changes in the protection systems of others:
- R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions, [including those for the Generator Interconnection Facility](#), that could require changes in the Transmission Operator’s protection systems.
- R5.2.** Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators’ protection systems.
- R6.** Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

### **C. Measures**

- M1.** Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.
- M2.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Special Protection Systems in its area. (Requirement 6 Part 1)
- M3.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Special Protection Systems. (Requirement 6 Part 2)

### **D. Compliance**

#### **1. Compliance Monitoring Process**

##### **1.1. Compliance Monitoring Responsibility**

Regional Reliability Organizations shall be responsible for compliance monitoring.

##### **1.2. Compliance Monitoring and Reset Time Frame**

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)



- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

### **1.3. Data Retention**

Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measures 2 and 3.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

### **1.4. Additional Compliance Information**

None.

## **2. Levels of Non-Compliance for Generator Operators:**

- 2.1. Level 1:** Not applicable.
- 2.2. Level 2:** Not applicable.
- 2.3. Level 3:** Not applicable.
- 2.4. Level 4:** Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.

## **3. Levels of Non-Compliance for Transmission Operators:**

- 3.1. Level 1:** Not applicable.
- 3.2. Level 2:** Not applicable.
- 3.3. Level 3:** Not applicable.

3.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Failed to provide evidence of coordination when installing new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities as specified in R3.2.

3.4.2 Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

4. **Levels of Non-Compliance for Balancing Authorities:**

4.1. **Level 1:** Not applicable.

4.2. **Level 2:** Not applicable.

4.3. **Level 3:** Not applicable.

4.4. **Level 4:** Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

**E. Regional Differences**

None identified.

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	August 25, 2005	Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
<u>X</u>	<u>TBD</u>	<u>Modified R1, R2, R3, R3.1, R5, and R5.1 to include the Generator Interconnection Facility.</u>	<u>Addition</u>

## A. Introduction

1. **Title:** Analysis and Mitigation of Transmission and Generation Protection System Misoperations
2. **Number:** PRC-004-~~X1~~
3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.
4. **Applicability**
  - 4.1. Transmission Owner.
  - 4.2. Distribution Provider that owns a transmission Protection System.
  - 4.3. Generator Owner.
5. **Effective Date:** ~~August 1, 2006~~ TBD

## B. Requirements

- R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1.
- R2. The Generator Owner shall analyze its generator Protection System Misoperations, including those for the Generator Interconnection Facility, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for PRC-003 R1.
- R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.

## C. Measures

- M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Reliability Organization procedures developed for PRC-003 R1.
- M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for PRC-003 R1.
- M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Reliability Organization procedures developed for PRC-003 R1.

## D. Compliance

1. **Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Regional Reliability Organization.

**1.2. Compliance Monitoring Period and Reset Time Frame**

One calendar year.

**1.3. Data Retention**

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

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

**1.4. Additional Compliance Information**

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

**2. Levels of Non-Compliance for Transmission Owners and Distribution Providers that own a Transmission Protection System:**

- 2.1. Level 1:** Documentation of Misoperations is complete according to PRC-004 R1, but documentation of Corrective Action Plans is incomplete.
- 2.2. Level 2:** Documentation of Misoperations is incomplete according to PRC-004 R1 and documentation of Corrective Action Plans is incomplete.
- 2.3. Level 3:** Documentation of Misoperations is incomplete according to PRC-004 R1 and there are no associated Corrective Action Plans.
- 2.4. Level 4:** Misoperations have not been analyzed and documentation has not been provided to the Regional Reliability Organization according to Requirement 3.

**3. Levels of Non-Compliance for Generator Owners**

- 3.1. Level 1:** Documentation of Misoperations is complete according to PRC-004 R2, but documentation of Corrective Action Plans is incomplete.
- 3.2. Level 2:** Documentation of Misoperations is incomplete according to PRC-004 R2 and documentation of Corrective Action Plans is incomplete.
- 3.3. Level 3:** Documentation of Misoperations is incomplete according to PRC-004 R2 and there are no associated Corrective Action Plans.
- 3.4. Level 4:** Misoperations have not been analyzed and documentation has not been provided to the Regional Reliability Organization according to R3.

**E. Regional Differences**

None identified.

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	<ol style="list-style-type: none"> <li>1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>2. Added “periods” to items where appropriate.</li> </ol> Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
<u>X</u>	<u>TBD</u>	<u>Modified R2 to include the Generator Interconnection Facility</u>	<u>Addition</u>

## A. Introduction

1. **Title:** **Transmission and Generation Protection System Maintenance and Testing**
2. **Number:** PRC-005-~~X1~~
3. **Purpose:** To ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested.
4. **Applicability**
  - 4.1. Transmission Owner.
  - 4.2. Generator Owner.
  - 4.3. Distribution Provider that owns a transmission Protection System.
5. **Effective Date:** ~~May 1, 2006~~

## B. Requirements

- R1. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System, [including those for the Generator Interconnection Facility](#), shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:
  - R1.1. Maintenance and testing intervals and their basis.
  - R1.2. Summary of maintenance and testing procedures.
- R2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System, [including those for the Generator Interconnection Facility](#) shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include:
  - R2.1. Evidence Protection System devices were maintained and tested within the defined intervals.
  - R2.2. Date each Protection System device was last tested/maintained.

## C. Measures

- M1. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System that affects the reliability of the BES, shall have an associated Protection System maintenance and testing program as defined in Requirement 1.
- M2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System that affects the reliability of the BES, shall have evidence it provided documentation of its associated Protection System maintenance and testing program and the implementation of its program as defined in Requirement 2.

## D. Compliance

1. **Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Regional Reliability Organization.

**1.2. Compliance Monitoring Period and Reset Time Frame**

One calendar year.

**1.3. Data Retention**

The Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System, shall retain evidence of the implementation of its Protection System maintenance and testing program for three years.

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

**1.4. Additional Compliance Information**

The Transmission Owner and any Distribution Provider that owns a transmission Protection System and the Generator Owner that owns a generation Protection System, shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

**2. Levels of Non-Compliance**

- 2.1. Level 1:** Documentation of the maintenance and testing program provided was incomplete as required in R1, but records indicate maintenance and testing did occur within the identified intervals for the portions of the program that were documented.
- 2.2. Level 2:** Documentation of the maintenance and testing program provided was complete as required in R1, but records indicate that maintenance and testing did not occur within the defined intervals.
- 2.3. Level 3:** Documentation of the maintenance and testing program provided was incomplete, and records indicate implementation of the documented portions of the maintenance and testing program did not occur within the identified intervals.
- 2.4. Level 4:** Documentation of the maintenance and testing program, or its implementation, was not provided.

**E. Regional Differences**

None identified.

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	<ul style="list-style-type: none"> <li>1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash” (—).</li> <li>2. Added “periods” to items where appropriate.</li> <li>3. Changed “Timeframe” to “Time Frame”</li> </ul>	01/20/05

Standard PRC-005-~~X~~4 — Transmission and Generation Protection System Maintenance and Testing

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		in item D, 1.2.	
<u>X</u>	<u>TBD</u>	<u>Modified R1 and R2 to include the Generator Interconnection Facility</u>	<u>Additions</u>



## A. Introduction

1. **Title:** Reliability Responsibilities and Authorities

2. **Number:** TOP-001-X1

3. **Purpose:**

To ensure reliability entities have clear decision-making authority and capabilities to take appropriate actions or direct the actions of others to return the transmission system to normal conditions during an emergency.

4. **Applicability**

4.1. Balancing Authorities

4.2. Transmission Operators

4.3. Generator Operators

4.4. Distribution Providers

4.5. Load Serving Entities

5. **Effective Date:** ~~January 1, 2007~~ TBD

## B. Requirements

**R1.** Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.

**R2.** Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.

**R3.** Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.

**R4.** Each Distribution Provider and Load Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.

**R5.** Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.

- R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.
- R7. Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities, [including the Generator Interconnection Facility](#), from service if removing those facilities would burden neighboring systems unless:
- ~~1.~~[R7.1.](#) For a generator outage, [including the Generator Interconnection Facility](#), the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.
- ~~2.~~[R7.2.](#) For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.
- ~~3.~~[R7.3.](#) When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.
- R8. During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.
- [R9. The Generator Operator, in accord with the expectations defined by the Transmission Operator, shall coordinate the operation of its Generator Interconnection Facility with the Transmission Operator to whom it interconnects in order to preserve Interconnection reliability with respect to the following:](#)
- [Switching elements](#)
  - [Outage planning](#)
  - [Real-time or anticipated emergency conditions](#)
  - [Other conditions mutually agreed upon by the Generator Operator and Transmission Operator](#)
- [R10. The Transmission Operator shall have decision-making authority over operation of the Generator Interconnection Operational Interface at all times in order to preserve Interconnection reliability.](#)

~~—The Generator Operator shall take the action it deems appropriate to remove from service the Generator Interconnection Facilities when safety is jeopardized or equipment damage is imminent.~~

~~—The Generator Operator shall notify the Transmission Operator as soon as practical of the actions taken and the reasons therein.~~

### C. Measures

- M1.** Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, signed agreements, an authority letter signed by an officer of the company, or other equivalent evidence that will be used to confirm that it has the authority, and has exercised the authority, to alleviate operating emergencies as described in Requirement 1.
- M2.** If an operating emergency occurs the Transmission Operator that experienced the emergency shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it took immediate actions to alleviate the operating emergency including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc. (Requirement 2)
- M3.** Each Transmission Operator, Balancing Authority, and Generator Operator shall have and provide upon request evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it complied with its Reliability Coordinator's reliability directives. If the Transmission Operator, Balancing Authority or Generator Operator did not comply with the directive because it would violate safety, equipment, regulatory or statutory requirements, it shall provide evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that it immediately informed the Reliability Coordinator of its inability to perform the directive. (Requirement 3)
- M4.** Each Balancing Authority, Generator Operator, Distribution Provider and Load Serving Entity shall have and provide upon request evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it complied with its Transmission Operator's reliability directives. If the Balancing Authority, Generator Operator, Distribution Provider and Load Serving Entity did not comply with the directive because it would violate safety, equipment, regulatory or statutory requirements, it shall provide evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that it immediately informed the Transmission Operator of its inability to perform the directive. (Requirements 3 and 4)
- M5.** The Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it informed its Reliability Coordinator and any other potentially affected

Transmission Operators of real time or anticipated emergency conditions, and took actions to avoid, when possible, or to mitigate an emergency. (Requirement 5)

- M6.** The Transmission Operator, Balancing Authority, and Generator Operator shall each have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it rendered assistance to others as requested, provided that the requesting entity had implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements. (Requirement 6)
- M7.** The Transmission Operator and Generator Operator shall each have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it notified either their Transmission Operator in the case of the Generator Operator, or other Transmission Operators, and the Reliability Coordinator when it removed Bulk Electric System facilities from service if removing those facilities would burden neighboring systems. (Requirement 7)

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Monitoring Responsibility**

Regional Reliability Organizations shall be responsible for compliance monitoring.

#### **1.2. Compliance Monitoring and Reset Time Frame**

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

#### **1.3. Data Retention**

Each Transmission Operator shall have the current in-force document to show that it has the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area. (Measure 1)

Each Transmission Operator shall keep 90 days of historical data (evidence) for Measures 1 through 7, including evidence of directives issued for Measures 3 and 4.

Each Balancing Authority shall keep 90 days of historical data (evidence) for Measures 3, 4 and 6 including evidence of directives issued for Measures 3 and 4.

Each Generator Operator shall keep 90 days of historical data (evidence) for Measures 3, 4, 6 and 7 including evidence of directives issued for Measures 3 and 4.

Each Distribution Provider and Load-serving Entity shall keep 90 days of historical data (evidence) for Measure 4.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance for a Balancing Authority:**

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

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

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

**2.4. Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

**2.4.1** Did not comply with a Reliability Coordinator's or Transmission Operator's reliability directive or did not immediately inform the Reliability Coordinator or Transmission Operator of its inability to perform that directive (R3)

**2.4.2** Did not render emergency assistance to others as requested, in accordance with R6.

**3. Levels of Non-Compliance for a Transmission Operator**

**3.1. Level 1:** Not applicable.

**3.2. Level 2:** Not applicable.

**3.3. Level 3:** Not applicable.

**3.4. Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

- 3.4.1 Does not have the documented authority to act as specified in R1.
- 3.4.2 Does not have evidence it acted with the authority specified in R1.
- 3.4.3 Did not take immediate actions to alleviate operating emergencies as specified in R2.
- 3.4.4 Did not comply with its Reliability Coordinator's reliability directive or did not immediately inform the Reliability Coordinator of its inability to perform that directive, as specified in R3.
- 3.4.5 Did not inform its Reliability Coordinator and other potentially affected Transmission Operators of real time or anticipated emergency conditions as specified in R5.
- 3.4.6 Did not take actions to avoid, when possible, or to mitigate an emergency as specified in R5.
- 3.4.7 Did not render emergency assistance to others as requested, as specified in R6.
- 3.4.8 Removed Bulk Electric System facilities from service under conditions other than those specified in R7.1, 7.2, and 7.3, and removing those facilities burdened a neighbor system.

**4. Levels of Non-Compliance for a Generator Operator:**

- 4.1. **Level 1:** Not applicable.
- 4.2. **Level 2:** Not applicable.
- 4.3. **Level 3:** Not applicable.
- 4.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:
  - 4.4.1 Did not comply with a Reliability Coordinator or Transmission Operator's reliability directive or did not immediately inform the Reliability Coordinator or Transmission Operator of its inability to perform that directive, as specified in R3.
  - 4.4.2 Did not render all available emergency assistance to others as requested, unless such actions would violate safety, equipment, or regulatory or statutory requirements as specified in R6.
  - 4.4.3 Removed Bulk Electric System facilities from service under conditions other than those specified in R7.1, 7.2, and 7.3, and burdened a neighbor system.

**5. Levels of Non-Compliance for a Distribution Provider or Load Serving Entity**

- 5.1. **Level 1:** Not applicable.
- 5.2. **Level 2:** Not applicable.
- 5.3. **Level 3:** Not applicable

5.4. **Level 4:** Did not comply with a Transmission Operator’s reliability directive or immediately inform the Transmission Operator of its inability to perform that directive, as specified in R4.

**E. Regional Differences**

None identified.

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
<u>X</u>	<u>TBD</u>	<u>Modified R7 and R7.1 to include the Generator Interconnection Facility</u> <u>Added new Requirements R<del>4</del>9 and</u> <u>R10, and R<del>11</del>.</u>	<u>Addition</u>



## A. Introduction

1. **Title:** Normal Operations Planning
2. **Number:** TOP-002-~~X~~2
3. **Purpose:** Current operations plans and procedures are essential to being prepared for reliable operations, including response for unplanned events.
4. **Applicability**
  - 4.1. Balancing Authority.
  - 4.2. Transmission Operator.
  - 4.3. Generator Operator.
  - 4.4. Load Serving Entity.
  - 4.5. Transmission Service Provider.
5. **Effective Date:** ~~January 1, 2007~~TBD  
Six months after effective date of VAR-001-1.

## B. Requirements

- R1. Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.
- R2. Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.
- R3. Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations, including for the Generator Interconnection Facility, with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.
- R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.
- R5. Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.



- R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.
- R7. Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.
- R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.
- R9. Each Balancing Authority shall plan to meet Interchange Schedules and ramps.
- R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).
- R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.
- R12. The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.
- R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.
- R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:
  - R14.1. Changes in real and reactive output capabilities. (Retired August 1, 2007)
  - R14.1. **Changes in real output capabilities. (Effective August 1, 2007)**
  - R14.2. Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)
  - R14.2. Changes in Generator Interconnection Facility Status
- R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).
- R16. Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator

and Balancing Authority of changes in capabilities and characteristics including but not limited to:

**R16.1.** Changes in transmission facility status.

**R16.2.** Changes in transmission facility rating.

**R17.** Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.

**R18.** Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network [and for the Generator Interconnection Facility](#).

**R19.** Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.

### **C. Measures**

**M1.** Each Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, documented planning procedures, copies of current day plans, copies of seasonal operations plans, or other equivalent evidence that will be used to confirm that it maintained a set of current plans. (Requirement 1 Part 1).

**M2.** Each Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, copies of current day plans or other equivalent evidence that will be used to confirm that its plans address Requirements 5, 6, and 10.

**M3.** Each Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, copies of current day plans or other equivalent evidence that will be used to confirm that its plans address Requirements 7, 8, and 9.

**M4.** Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, its next-day, and current-day Bulk Electric System studies used to determine SOLs or other equivalent evidence that will be used to confirm that its studies reflect current system conditions. (Requirement 11 Part 1)

**M5.** Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that the results of Bulk Electric System studies were made available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator. (Requirement 11 Part 2)

**M6.** Each Generator Operator shall have and provide upon request evidence that, when requested by either a Transmission Operator or Balancing Authority, it performed a generating real and reactive capability verification and provided the results to the requesting entity in accordance with Requirement 13.

- M7.** Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that without any intentional time delay, it notified its Balancing Authority and Transmission Operator of changes in real and reactive capabilities and AVR status. (Requirement 14)
- M8.** Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that, on request, it provided a forecast of expected real power output to assist in operations planning. (Requirement 15)
- M9.** Each Transmission Operators shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that, without any intentional time delay, it notified its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics. (Requirement 16)
- M10.** Each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider and Load Serving Entity shall have and provide upon request evidence that could include, but is not limited to, a list of interconnected transmission facilities and their line identifiers at each end or other equivalent evidence that will be used to confirm that it used uniform line identifiers when referring to transmission facilities of an interconnected network. (Requirement 18)

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Monitoring Responsibility**

Regional Reliability Organizations shall be responsible for compliance monitoring.

#### **1.2. Compliance Monitoring and Reset Time Frame**

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 calendar days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

### 1.3. Data Retention

For Measures 1 and 2, each Transmission Operator shall have its current plans and a rolling 6 months of historical records (evidence).

For Measures 1, 2, and 3 each Balancing Authority shall have its current plans and a rolling 6 months of historical records (evidence).

For Measure 4, each Transmission Operator shall keep its current plans (evidence).

For Measures 5 and 9, each Transmission Operator shall keep 90 days of historical data (evidence).

For Measures 6, 7 and 8, each Generator Operator shall keep 90 days of historical data (evidence).

For Measure 10, each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider, and Load-serving Entity shall have its current list interconnected transmission facilities and their line identifiers at each end or other equivalent evidence as evidence.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

### 1.4. Additional Compliance Information

None.

## 2. Levels of Non-Compliance for Balancing Authorities:

**2.1. Level 1:** Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

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

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

**2.4. Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

**2.4.1** Did not maintain an updated set of current-day plans as specified in R1.

**2.4.2** Plans did not meet one or more of the requirements specified in R5 through R10.

## 3. Levels of Non-Compliance for Transmission Operators

- 3.1. **Level 1:** Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.
  - 3.2. **Level 2:** Not applicable.
  - 3.3. **Level 3:** One or more of Bulk Electric System studies were not made available as specified in R11.
  - 3.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:
    - 3.4.1 Did not maintain an updated set of current-day plans as specified in R1.
    - 3.4.2 Plans did not meet one or more of the requirements in R5, R6, and R10.
    - 3.4.3 Studies not updated to reflect current system conditions as specified in R11.
    - 3.4.4 Did not notify its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics as specified in R16.
4. **Levels of Non-Compliance for Generator Operators:**
- 4.1. **Level 1:** Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.
  - 4.2. **Level 2:** Not applicable.
  - 4.3. **Level 3:** Not applicable.
  - 4.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:
    - 4.4.1 Did not verify and provide a generating real and reactive capability verification and provide the results to the requesting entity as specified in R13.
    - 4.4.2 Did not notify its Balancing Authority and Transmission Operator of changes in capabilities and characteristics as specified in R14.
    - 4.4.3 Did not provide a forecast of expected real power output to assist in operations planning as specified in R15.
5. **Levels of Non-Compliance for Transmission Service Providers and Load-serving Entities:**
- 5.1. **Level 1:** Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.
  - 5.2. **Level 2:** Not applicable.
  - 5.3. **Level 3:** Not applicable.
  - 5.4. **Level 4:** Not applicable.

## E. Regional Differences

None identified.

### Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	June 14, 2007	Fixed typo in R11., (subject to ...)	Errata
<u>X</u>	<u>TBD</u>	<u>Modified R3 and R18 to include the Generator Interconnection Facility and added Requirement R14.3.</u>	<u>Addition</u>

## A. Introduction

1. **Title:** **Planned Outage Coordination**
2. **Number:** TOP-003-~~X0~~
3. **Purpose:** Scheduled generator and transmission outages that may affect the reliability of interconnected operations must be planned and coordinated among Balancing Authorities, Transmission Operators, and Reliability Coordinators.
4. **Applicability**
  - 4.1. Generator Operators.
  - 4.2. Transmission Operators.
  - 4.3. Balancing Authorities.
  - 4.4. Reliability Coordinators.
5. **Effective Date:** ~~April 1, 2005~~TBD

## B. Requirements

- R1. Generator Operators and Transmission Operators shall provide planned outage information, including information for the Generator Interconnection Facility.
  - R1.1. Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW) or the Generator Interconnection Facility. The Transmission Operator shall establish the outage reporting requirements.
  - R1.2. Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements.
  - R1.3. Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.
- R2. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.
- R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.
- R4. Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.

## C. Measures

- M1. Evidence that the Generator Operator, Transmission Operator, Balancing Authority, and Reliability Coordinator reported and coordinated scheduled outage information as indicated in the requirements above.

## D. Compliance

### 1. Compliance Monitoring Process

Each Regional Reliability Organization shall conduct a review every three years to ensure that each responsible entity has a process in place to provide planned generator and/or bulk transmission outage information to their Reliability Coordinator, and with neighboring Transmission Operators and Balancing Authorities.

Investigation: At the discretion of the Regional Reliability Organization or NERC, an investigation may be initiated to review the planned outage process of a monitored entity due to a complaint of non-compliance by another entity. Notification of an investigation must be made by the Regional Reliability Organization to the entity being investigated as soon as possible, but no later than 60 days after the event. The form and manner of the investigation will be set by NERC and/or the Regional Reliability Organization.

#### 1.1. Compliance Monitoring Responsibility

A Reliability Coordinator makes a request for an outage to “not be taken” because of a reliability impact on the grid and the outage is still taken. The Reliability Coordinator must provide all its documentation within three business days to the Regional Reliability Organization. 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

One calendar year without a violation from the time of the violation.

#### 1.3. Data Retention

One calendar year.

#### 1.4. Additional Compliance Information

Not specified.

### 2. Levels of Non-Compliance

**2.1. Level 1:** Each entity responsible for reporting information under Requirements R1 and R3 has a process in place to provide information to their Reliability Coordinator but does not have a process in place (where permitted by legal agreements) to provide this information to the neighboring Balancing Authority or Transmission Operator.

**2.2. Level 2:** N/A.

**2.3. Level 3:** N/A.

**2.4. Level 4:** There is no process in place to exchange outage information, or the entity responsible for reporting information under Requirements R1 to R3 does not follow the directives of the Reliability Coordinator to cancel or reschedule an outage.

## E. Regional Differences

None identified.



### Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
<a href="#">X</a>	<a href="#">TBD</a>	<a href="#">Modified R1 and R1.1 to include the Generator Interconnection Facility</a>	<a href="#">Addition</a>

**A. Introduction**

1. **Title:** Transmission Operations
2. **Number:** TOP-004-~~X2~~
3. **Purpose:** To ensure that the transmission system is operated so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single Contingency and specified multiple Contingencies.
4. **Applicability:**
  - 4.1. Transmission Operators
5. **Proposed Effective Date:** ~~Twelve months after BOT adoption of FAC-014~~[TBD](#).

**B. Requirements**

- R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).
- R2. Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.
- R3. Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.
- R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.
- R5. Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.
- R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including:
  - R6.1. Monitoring and controlling voltage levels and real and reactive power flows.
  - R6.2. Switching transmission elements.
  - R6.3. Planned outages of transmission elements.
  - R6.4. Responding to IROL and SOL violations.
- [R7. The Generator Operator shall operate its Generator Interconnection Facility within its applicable ratings.](#)

**C. Measures**

- M1. Each Transmission Operator that enters an unknown operating state for which valid limits have not been determined, shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, alarm program printouts, or other equivalent evidence that will be used to determine if it restored operations to respect proven reliable power system limits within 30 minutes as specified in Requirement 4.

- M2. Each Transmission Operator shall have and provide upon request current policies and procedures that address the execution and coordination of activities that impact inter- and intra-Regional reliability for each of the topics listed in Requirements 6.1 through 6.6.

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

#### 1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

#### 1.3. Data Retention

Each Transmission Operator shall keep 90 days of historical data for Measure 1.

Each Transmission Operator shall have current, in-force policies and procedures, as evidence of compliance to Measure 2.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

#### 1.4. Additional Compliance Information

None.

### 2. Levels of Non-Compliance:

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

2.2. **Level 2:** Did not have formal policies and procedures to address one of the topics listed in R6.1 through R6.4.

2.3. **Level 3:** Did not have formal policies and procedures to address two of the topics listed in R6.1 through R6.4.

**2.4. Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

**2.4.1** Did not restore operations to respect proven reliable power system limits within 30 minutes as specified in R4.

**2.4.2** Did not have formal policies and procedures to address three or all of the topics listed in R6.1 through R6.4.

**E. Regional Differences**

None identified.

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Added language from Missing Measures and Compliance Elements adopted by Board of Trustees on November 1, 2006	Revised
2	December 19, 2007	Revised to reflect merging of both sets of changes approved by BOT on November 1, 2006 (Addition of measures and compliance elements and revisions to R3 and R6 with conforming changes made as errata to Levels of Non-compliance)	Revised Errata
<u>X</u>	<u>TBD</u>	<u>Added Requirement R7</u>	<u>Addition</u>

## A. Introduction

1. **Title:** **Response to Transmission Limit Violations**
2. **Number:** TOP-008-X1
3. **Purpose:** To ensure Transmission Operators take actions to mitigate SOL and IROL violations.
4. **Applicability**
  - 4.1. Transmission Operators.
  - 4.2. Generator Operators.
5. **Effective Date:** ~~January 1, 2007~~TBD

## B. Requirements

- R1. The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.
- R2. Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.
- R3. The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.
- R4. The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.
- R5. The Generator Operator shall disconnect the Generator Interconnection Facility when safety is jeopardized or if the overload or abnormal voltage or reactive condition persists and generating equipment or the Generator Interconnection Facility is endangered. In doing so, the Generator Operator shall notify its Transmission Operator and Balancing Authority impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.

## C. Measures

- M1. The Transmission Operator involved in an SOL or IROL violation shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications, alarm program printouts, or other equivalent evidence that will be used to determine if it took immediate steps to relieve the condition. (Requirement 1)

- M2.** The Transmission Operator that disconnects an overloaded facility shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications, alarm program print outs, or other equivalent evidence that will be used to determine if it disconnected an overloaded facility in accordance with Requirement 3 Part 1
- M3.** The Transmission Operator that disconnects an overloaded facility shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it notified its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permitted, otherwise, immediately thereafter. (Requirement 3 Part 2)
- M4.** The Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, computer facilities documents, computer printouts, training documents, copies of analysis program results, operator logs or other equivalent evidence that will be used to confirm that it has sufficient information and analysis tools to determine the cause(s) of SOL violations. (Requirement 4 Part 1)
- M5.** The Transmission Operator that violates an SOL shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it used the results of these analyses to immediately mitigate the SOL violation. (Requirement 4 Part 3)

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Monitoring Responsibility**

Regional Reliability Organizations shall be responsible for compliance monitoring.

#### **1.2. Compliance Monitoring and Reset Time Frame**

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

**1.3. Data Retention**

Each Transmission Operator shall keep 90 days of historical data (evidence) for Measure 1, 2 and 3.

Each Transmission Operator shall have current documents as evidence of compliance to Measures 4 and 5.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance data

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance for Transmission Operator**

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

**2.2. Level 2:** Disconnected an overloaded facility as specified in R3 but did not notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, or immediately thereafter.

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

**2.4. Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

**2.4.1** Did not take immediate steps to relieve an IROL or SOL violation in accordance with R1.

**2.4.2** Did not disconnect an overloaded facility as specified in R3.

**2.4.3** Does not have sufficient information and analysis tools to determine the cause(s) of SOL violations. (R4 Part 1)

**2.4.4** Did not use the results of analyses to immediately mitigate an SOL violation. (R4 Part 3)

**E. Regional Differences**

None identified.

**Version History**

Version	Date	Action	Change Tracking
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Standard TOP-008-~~X~~4 — Response to Transmission Limit Violations

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0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
<u>X</u>	<u>TBD</u>	<u>Added new Requirement R5</u>	<u>Addition</u>

**A. Introduction**

1. **Title:** Voltage and Reactive Control
2. **Number:** VAR-001-~~X~~1
3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in real time to protect equipment and the reliable operation of the Interconnection.
4. **Applicability:**
  - 4.1. Transmission Operators.
  - 4.2. Purchasing-Selling Entities.
5. **Effective Date:** ~~Six months after BOT adoption.~~TBD

**B. Requirements**

- R1.** Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators.
- R2.** Each Transmission Operator shall acquire sufficient reactive resources within its area to protect the voltage levels under normal and Contingency conditions. This includes the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.
- R3.** The Transmission Operator shall specify criteria that exempts generators from compliance with the requirements defined in Requirement 4, and Requirement 6.1.
  - R3.1.** Each Transmission Operator shall maintain a list of generators in its area that are exempt from following a voltage or Reactive Power schedule.
  - R3.2.** For each generator that is on this exemption list, the Transmission Operator shall notify the associated Generator Owner.
- R4.** Each Transmission Operator shall specify a voltage or Reactive Power schedule <sup>1</sup> at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (AVR in service and controlling voltage).
- R5.** Each Purchasing-Selling Entity shall arrange for (self-provide or purchase) reactive resources to satisfy its reactive requirements identified by its Transmission Service Provider.
- R6.** The Transmission Operator shall know the status of all transmission Reactive Power resources, including the status of voltage regulators and power system stabilizers.
  - R6.1.** When notified of the loss of an automatic voltage regulator control, the Transmission Operator shall direct the Generator Operator to maintain or change either its voltage schedule or its Reactive Power schedule.
- R7.** The Transmission Operator shall be able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow.

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<sup>1</sup> The voltage schedule is a target voltage to be maintained within a tolerance band during a specified period.

- R8.** Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – including reactive generation scheduling; transmission line, [Generator Interconnection Facility](#), and reactive resource switching; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits.
- R9.** Each Transmission Operator shall maintain reactive resources to support its voltage under first Contingency conditions.
  - R9.1.** Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when Contingencies occur.
- R10.** Each Transmission Operator shall correct IROL or SOL violations resulting from reactive resource deficiencies (IROL violations must be corrected within 30 minutes) and complete the required IROL or SOL violation reporting.
- R11.** After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes.
- R12.** The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.

### **C. Measures**

- M1.** The Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule as specified in Requirement 4 to each Generator Operator it requires to follow such a schedule.
- M2.** The Transmission Operator shall have evidence to show that, for each generating unit in its area that is exempt from following a voltage or Reactive Power schedule, the associated Generator Owner was notified of this exemption in accordance with Requirement 3.2.
- M3.** The Transmission Operator shall have evidence to show that it issued directives as specified in Requirement 6.1 when notified by a Generator Operator of the loss of an automatic voltage regulator control.
- M4.** The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with Requirement 11.

### **D. Compliance**

#### **1. Compliance Monitoring Process**

##### **1.1. Compliance Monitoring Responsibility**

Regional Reliability Organization.

##### **1.2. Compliance Monitoring Period and Reset Time Frame**

One calendar year.

##### **1.3. Data Retention**

The Transmission Operator shall retain evidence for Measures 1 through 4 for 12 months.

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

##### **1.4. Additional Compliance Information**

The Transmission Operator shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

**2. Levels of Non-Compliance**

- 2.1. Level 1:** No evidence that exempt Generator Owners were notified of their exemption as specified under R3.2
- 2.2. Level 2:** There shall be a level two non-compliance if either of the following conditions exists:
  - 2.2.1** No evidence to show that directives were issued in accordance with R6.1.
  - 2.2.2** No evidence that documentation was provided to Generator Owner when a change was needed to a generating unit’s step-up transformer tap in accordance with R11.
- 2.3. Level 3:** There shall be a level three non-compliance if either of the following conditions exists:
  - 2.3.1** Voltage or Reactive Power schedules were provided for some but not all generating units as required in R4.
- 2.4. Level 4:** No evidence voltage or Reactive Power schedules were provided to Generator Operators as required in R4.

**D. Regional Differences**

None identified.

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	Revised
1	July 3, 2007	Added “Generator Owners” and “Generator Operators” to Applicability section.	Errata
1	August 23, 2007	Removed “Generator Owners” and “Generator Operators” to Applicability section.	Errata
<u>X</u>	<u>TBD</u>	<u>Modified R8 to include Generator Interconnection Facility</u>	<u>Addition</u>

## A. Introduction

1. **Title:** Generator Operation for Maintaining Network Voltage Schedules
2. **Number:** VAR-002-~~X~~1a
3. **Purpose:** To ensure generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and the reliable operation of the Interconnection.
4. **Applicability**
  - 4.1. Generator Operator.
  - 4.2. Generator Owner.
5. **Effective Date:** ~~May 13, 2009~~TBD

## B. Requirements

- R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.
- R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings<sup>1</sup>) as directed by the Transmission Operator.
  - R2.1. When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.
  - R2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.
- R3. Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:
  - R3.1. A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.
  - R3.2. A status or capability change on any other Reactive Power resources under the Generator Operator's control, including the Generator Interconnection Facility, and the expected duration of the change in status or capability.
- R4. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.
  - R4.1. For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:
    - R4.1.1. Tap settings.
    - R4.1.2. Available fixed tap ranges.

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<sup>1</sup> When a Generator is operating in manual control, reactive power capability may change based on stability considerations and this will lead to a change in the associated Facility Ratings.

**R4.1.3.** Impedance data.

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

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

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

### **C. Measures**

**M1.** The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode as specified in Requirement 1.

**M2.** The Generator Operator shall have evidence to show that it controlled its generator voltage and reactive output to meet the voltage or Reactive Power schedule provided by its associated Transmission Operator as specified in Requirement 2.

**M3.** The Generator Operator shall have evidence to show that it responded to the Transmission Operator's directives as identified in Requirement 2.1 and Requirement 2.2.

**M4.** The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any of the changes identified in Requirement 3.

**M5.** The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up transformers and auxiliary transformers as required in Requirements 4.1.1 through 4.1.4

**M6.** The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation as identified in Requirement 5.

**M7.** The Generator Operator shall have evidence that it notified its associated Transmission Operator when it couldn't comply with the Transmission Operator's step-up transformer tap specifications as identified in Requirement 5.1.

### **D. Compliance**

#### **1. Compliance Monitoring Process**

##### **1.1. Compliance Monitoring Responsibility**

Regional Reliability Organization.

##### **1.2. Compliance Monitoring Period and Reset Time Frame**

One calendar year.

##### **1.3. Data Retention**

The Generator Operator shall maintain evidence needed for Measure 1 through Measure 5 and Measure 7 for the current and previous calendar years.

The Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. (Measure 6)

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

**1.4. Additional Compliance Information**

The Generator Owner and Generator Operator shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

**2. Levels of Non-Compliance for Generator Operator**

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

**2.1.1** One incident of failing to notify the Transmission Operator as identified in , R3.1, R3.2 or R5.1.

**2.1.2** One incident of failing to maintain a voltage or reactive power schedule (R2).

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

**2.2.1** More than one but less than five incidents of failing to notify the Transmission as identified in R1, R3.1,R3.2 or R5.1.

**2.2.2** More than one but less than five incidents of failing to maintain a voltage or reactive power schedule (R2).

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

**2.3.1** More than five but less than ten incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.

**2.3.2** More than five but less than ten incidents of failing to maintain a voltage or reactive power schedule (R2).

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

**2.4.1** Failed to comply with the Transmission Operator’s directives as identified in R2.

**2.4.2** Ten or more incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.

**2.4.3** Ten or more incidents of failing to maintain a voltage or reactive power schedule (R2).

**3. Levels of Non-Compliance for Generator Owner:**

**3.1.1 Level One:** Not applicable.

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

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

**3.1.4 Level Four:** Did not ensure generating unit step-up transformer settings were changed in compliance with the specifications provided by the Transmission Operator as identified in R5.

**Standard VAR-002-~~1X~~-1a — Generator Operation for Maintaining Network Voltage Schedules**

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**E. Regional Differences**

None identified.

**F. Associated Documents**

1. Appendix 1 – Interpretation of Requirements R1 and R2 (August 1, 2007).

**Version History**

Version	Date	Action	Change Tracking
1	May 15, 2006	Added “(R2)” to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.	July 5, 2006
1a	December 19, 2007	Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007	Revised
1a	January 16, 2007	In Section A.2., Added “a” to end of standard number. Section F: added “1.”; and added date.	Errata
1.1a	October 29, 2008	BOT adopted errata changes; updated version number to “1.1a”	Errata
1.1a	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
<u>X</u>	<u>TBD</u>	<u>Modified R3.2 to include the Generator Interconnection Facility</u>	<u>Addition</u>



## Appendix 1

### Interpretation of Requirements R1 and R2

#### Request:

Requirement R1 of Standard VAR-002-1 states that Generation Operators shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (*automatic voltage regulator in service and controlling voltage*) unless the Generator Operator has notified the Transmission Operator.

Requirement R2 goes on to state that each Generation Operator shall maintain the generator voltage *or Reactive Power output* as directed by the Transmission Operator.

The two underlined phrases are the reasons for this interpretation request.

Most generation excitation controls include a device known as the Automatic Voltage Regulator, or AVR. This is the device which is referred to by the R1 requirement above. Most AVR's have the option of being set in various operating modes, such as constant voltage, constant power factor, and constant Mvar.

In the course of helping members of the WECC insure that they are in full compliance with NERC Reliability Standards, I have discovered both Transmission Operators and Generation Operators who have interpreted this standard to mean that AVR operation in the constant power factor or constant Mvar modes complies with the R1 and R2 requirements cited above. Their rationale is as follows:

- The AVR is clearly in service because it is operating in one of its operating modes
- The AVR is clearly controlling voltage because to maintain constant PF or constant Mvar, it controls the generator terminal voltage
- R2 clearly gives the Transmission Operator the option of directing the Generation Operator to maintain a constant reactive power output rather than a constant voltage.

Other parties have interpreted this standard to require operation in the constant voltage mode only. Their rationale stems from the belief that the purpose of the VAR-002-1 standard is to insure the automatic delivery of additional reactive to the system whenever a voltage decline begins to occur.

The material impact of misinterpretation of these standards is twofold.

- First, misinterpretation may result in reduced reactive response during system disturbances, which in turn may contribute to voltage collapse.
- Second, misinterpretation may result in substantial financial penalties imposed on generation operators and transmission operators who believe that they are in full compliance with the standard.

In accordance with the NERC Reliability Standards Development Procedure, I am requesting that a formal interpretation of the VAR-002-1 standard be provided. Two specific questions need to be answered.

- First, does AVR operation in the constant PF or constant Mvar modes comply with R1?
- Second, does R2 give the Transmission Operator the option of directing the Generation Owner to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

**Interpretation:**

1. First, does AVR operation in the constant PF or constant Mvar modes comply with R1?

**Interpretation:** No, only operation in constant voltage mode meets this requirement. This answer is predicated on the assumption that the generator has the physical equipment that will allow such operation and that the Transmission Operator has not directed the generator to run in a mode other than constant voltage.

2. Second, does R2 give the Transmission Operator the option of directing the Generation Owner (sic) to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

**Interpretation:** Yes, if the Transmission Operator specifically directs a Generator Operator to operate the AVR in a mode other than constant voltage mode, then that directed mode of AVR operation is allowed.

The logo for NERC (North American Electric Reliability Corporation) features the letters "NERC" in a bold, black, sans-serif font. A horizontal blue bar is positioned directly beneath the letters.

NORTH AMERICAN ELECTRIC  
RELIABILITY CORPORATION

A large, steel lattice transmission tower stands against a light sky, with power lines extending from it. The tower is partially obscured by a dark blue curved shape in the top right corner of the page.

# Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface

A faint, light blue map of North America is visible in the background of the lower half of the page.

to ensure  
the reliability of the  
bulk power system

November 16, 2009

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# Executive Summary

## Conclusions

1. Generator Interconnection Facilities operating at a voltage of 100 kV or greater or those deemed critical to the Bulk Electric System by the Regional Entity makes the Generator Interconnection Facility part of the Bulk Electric System for purposes of applying Generator Owner and Generator Operator requirements but not for applying Transmission Owner or Transmission Operator requirements.
2. The Generator Owner or Generator Operator that owns and/or operates a Generator Interconnection Facility, that is, a sole-use facility that interconnects the generator to the grid, should not be registered as a Transmission Owner or Transmission Operator by virtue of owning or operating its Generator Interconnection Facility.
3. A Generator Interconnection Facility is considered as though part of the generating facility specifically for purposes of applying Reliability Standards to a Generator Owner or Generator Operator.
4. Changes to NERC Reliability Standards are needed to ensure complete reliability coverage of the Generator Interconnection Facility.
  - a. 32 NERC Reliability Standard requirements contain language regarding generators or generating facilities for which greater clarity regarding its Generator Interconnection Facilities would ensure that no reliability gap exists.
  - b. 12 requirements in FAC-003-1 – Transmission Vegetation Management should have their applicability expanded to include Generator Owners.
  - c. 2 NERC Reliability Standards should have their applicability expanded to include Generator Operators to address general reliability gaps not attributable to the Generator Interconnection Facility.
  - d. 8 new Reliability Standard requirements should be added to ensure the responsibilities for owning and operating the Generator Interconnection Facility are clear, and to address certain requirements that should apply to all generators regardless of interconnection configuration.
5. If a generator is connected to multiple transmission facilities that are subject to network power flows (that is, power flow on these multiple transmission facilities includes power not solely associated with the generator output, requirements for station service, auxiliary load, or cogeneration load), then those transmission facilities are integrated transmission facilities and should be subjected to the applicable Transmission Owner and Transmission Operator Standard Requirements<sup>1</sup>.
6. After review of the existing Transmission Owner requirements that are not currently applicable to Generator Owners, only FAC-003-1 should have its applicability expanded to include Generator Owners as a result of the Generator Interconnection Facility, if the length

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<sup>1</sup> A double-circuit line behind the point of interconnection, for example, that is carrying power solely associated with the generation output, requirements for station service, auxiliary load, or cogeneration load, would not be considered an integrated transmission facility by comparison.



of the Generator Interconnection Facility exceeds two spans (generally, more than one-half mile) from the generator property line.

7. After review of the existing Transmission Operator requirements that are not currently applicable to Generator Operators, no existing Transmission Operator requirements should apply to Generator Operators as a result of the Generator Interconnection Facility.
8. New NERC Glossary definitions are needed for Generator Interconnection Facility and Generator Interconnection Operational Interface, as well as modifications to the terms Vegetation Inspection, Right-of-Way, Generator Owner, Generator Operator, and Transmission.

## Recommendations

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1. Submit Standards Authorization Requests (SARs) requesting expeditious action to add or modify the definitions in NERC's Glossary for Generator Interconnection Facility and Generator Interconnection Operational Interface, as well as modifications to the terms Vegetation Inspection, Right-of-Way, Generator Owner, Generator Operator, and Transmission.
2. Submit SARs requesting expeditious action to modify existing standard requirements to add specificity for Generator Interconnection Facility where appropriate, to add Generator Operator applicability where needed, to add requirements to capture responsibilities for owning and operating the Generator Interconnection Facility, and to add requirements where necessary that should be applicable to Generator Operators regardless of the interconnection configuration.
3. Modify the applicability of FAC-003-1 to apply to Generator Owners when their Generator Interconnection Facility operates at 200 kV or above and exceeds two spans from the generator property line, or otherwise is deemed to be critical to the Bulk Electric System.
4. Modify the NERC Rules of Procedure, NERC Compliance Registry Criteria, and other documents as necessary to reflect that a Generator Owner should not be registered as a Transmission Owner and a Generator Operator should not be registered as a Transmission Operator on the basis of the Generator Interconnection Facility.
5. NERC and the Regional Entities should refrain from further registering Generator Owners and Generator Operators as Transmission Owners and Transmission Operators generically by virtue of the Generator Interconnection Facility.
6. Based on the conclusions and recommendations offered in this report, NERC and the Regional Entities should carefully develop and implement a plan to address de-registering those Generator Owners and Generator Operators that have previously been registered as a Transmission Owner and Transmission Operator by virtue of the Generator Interconnection Facility.



# Discussion

## ***Historical Perspective***

On January 14, 2008, the NERC Board of Trustees Compliance Committee rendered a decision upholding the Western Electricity Coordinating Council's (WECC's) determination to register the New Harquahala Generating Company ("Harquahala") as a Transmission Owner and Transmission Operator. This determination is based on Harquahala's 26-mile 500 kV interconnection facilities that connect the plant with the Hassayampa transmission substation. In its determination, NERC concluded that:

- Harquahala met its glossary definition of "Transmission Owner" and "Transmission Operator";
- Harquahala's interconnection facilities are integrated transmission elements as described in NERC's Compliance Registry because they interconnect the generating facility to the transmission grid; and,
- Harquahala as a generating facility and the transmission station to which it interconnects are material to the Bulk Power System.

As a result, NERC found that Harquahala must be registered as a Transmission Owner and Transmission Operator in order to provide for proper coordination between Harquahala and Salt River Project, owner and operator of the Hassayampa substation, and for proper operation and maintenance of the interconnection facilities. NERC stated that a reliability gap exists because several high risk Reliability Standards do not otherwise apply to Harquahala under its other registration functions including those for vegetation management; taking corrective action if a protective relay failure reduces system reliability; coordinating protection systems; analyzing protection system misoperations and developing a corrective action plan to avoid future misoperations; developing procedures for monitoring voltage levels and reactive flow; and exercising the responsibility and clear decision-making authority to take actions needed to ensure the reliability of its area and to take action to alleviate operating emergencies. NERC stated, "from a reliability perspective and from the standpoint of section 215 of the FPA, this transmission line is integrated with other elements of the [Bulk Power System] requiring coordination of operation with those other elements." NERC also noted that Harquahala's registration status is based on ownership of its generation facilities, while its Transmission Owner and Transmission Operator status are based on ownership and operation of the transmission facilities.

In its appeal to FERC, Harquahala argued that its interconnection facilities were not integrated transmission elements; that its facilities will not have a material impact on the Bulk-Power System; that registration as a Transmission Owner and Transmission Operator is unwarranted because there is no reliability gap; and that its registration as such would result in inconsistent registrations in WECC and other regions. Harquahala notably did not contest that its interconnection facilities were part of the Bulk Power System.

FERC denied Harquahala's appeal on the material impact of the assets to the reliability of the Bulk Power System, but declined to address issues regarding the NERC Compliance Registry Criteria and the definition of "integrated transmission element." FERC noted that "if Harquahala



is only registered as a Generator Owner and Generator Operator, and not a Transmission Owner and Transmission Operator, it will not be required to have its staff trained and NERC-certified to operate these facilities in an emergency or to coordinate protection for its transmission line and switchyard with other transmission operators and the Regional Entity.” Further, FERC noted that if adequate reliability requirements were not provided on Harquahala’s tie-line, there is a reliability risk affecting a significant portion of the Bulk Power System in WECC confirming that a reliability gap exists. Significantly, FERC indicated that its finding in this case is case-specific and not one that all tie-line owners and operators should now be registered as Transmission Owners and Transmission Operators. Because Harquahala cannot physically comply with all transmission owner and transmission operator requirements in NERC standards, FERC directed NERC and Harquahala to negotiate those that will be applicable to them. This activity was completed in July, 2008.

The impact of the Harquahala registration decision manifested itself in a concern by some Generator Owners and Generator Operators regarding the criteria (or the lack thereof) that would be used to consistently determine whether other Generator Owners and Generator Operators would be also subject to registration as a Transmission Owner and Transmission Operator. In addition to the Harquahala case, there have been a small number of similar appeals to registration decisions on this issue that resulted in the registration of Generator Owners and or Generator Operators as Transmission Owners and or Operators. It is not clearly known the number of Generator Owners and Generator Operators also registered as Transmission Owners and Transmission Operators by virtue of its interconnection facilities that have chosen not to appeal.

In response to this growing concern, NERC undertook a survey in the Fall, 2008 to identify the specific nature of the concerns, to review and highlight those Transmission Owner and Transmission Operator requirements that should be considered for generic applicability to Generator Owners and Generator Operators by virtue of their interconnection facilities, and to collect ideas for how the issue could be resolved. There were wide-ranging viewpoints to the topic from the over 100 respondents but there was no support for merely assigning all Transmission Owner and Transmission Operator Requirements to the Generator Owner and Generator Operator on the basis of their interconnection facilities. One consistent suggestion was to assemble a group of industry representatives to analyze and make recommendations for resolving the issue, thereby establishing general criteria for determining whether Generator Owners and Generator Operators should be registered for Transmission Owner and Transmission Operator requirements in NERC’s Reliability Standards.

Accordingly, in February, 2009, NERC announced the formation of the Ad Hoc Group for Generator Requirements at the Transmission Interface.

### ***Team Objective***

“Evaluate existing NERC Reliability Standard requirements and develop a recommendation and possible Standards Authorization Request to address gaps in reliability for interconnection facilities of the Generator Owner and expectations for the Generator Operator in operating those facilities. Propose strategies to address or resolve other related issues as appropriate.”

## ***Team Composition***

The team was selected to provide a cross-section of participants across different geographic regions and industry segments, specifically linked with various NERC technical groups, and representative of both the operating and planning perspectives. The size of the team was intentionally managed to foster an efficient and effective disposition of the team's obligations. The team consisted of the following members:

Scott Helyer, Chair	Tenaska, Inc.
Steven Cobb	Salt River Project
Keith Daniel	Georgia Transmission Corporation
Jeffrey Gillen	American Transmission Corporation
Anthony Jankowski	We Energies
Gregory Mason	Dynegy
Eric Mortenson	Exelon Energy Delivery
Timothy Ponseti	Tennessee Valley Authority
Kent Saathoff	Electric Reliability Council of Texas, Inc.
Gerry Adamski	NERC Staff Coordinator

## ***Problem Statement***

The team devoted effort at the outset to clearly define and understand the problem that the team was organized to address. In this deliberation and determination, the team developed the following problem statement, assumptions, and process description that it used to guide its activities thereafter as presented in **Exhibit 1**:

# Exhibit 1

## **Problem Statement:**

Certain equipment owned and/or operated by generators may be defined as part of the Bulk Electric System. As such, the team needs to determine which owner and operating requirements are needed for reliability purposes for these facilities and then identify the functional entity<sup>2</sup> accountable for compliance to those requirements.

## **Assumptions:**

1. There are pieces of equipment at 100 kV and above currently owned and operated by generators that may fall under the definition of Bulk Electric System and therefore are under the purview of the NERC Reliability Standards.
2. For pieces of equipment identified in assumption No. 1 above, at least one functional entity must be identified to be responsible for each standard requirement applicable to these facilities at an ownership and operating level, understanding that multiple ownership and operating arrangements exist.<sup>3</sup>
3. Separate the ownership expectations from the operating expectations in the discussion.
4. Current standard requirements assigned to Generator Owners and Generator Operators are appropriate.

## **Process to Address Identified Problem:**

1. Review the list of standard requirements applicable to Transmission Owners and/or Transmission Operators that are not currently applicable to Generator Owners and/or Generator Operators.
2. Determine which of the Transmission Owner standard requirements not assigned to Generator Owners should always be, never be, or could possibly be assigned to address potential reliability gaps based on the equipment owned by the Generator Owner.
3. Determine which of the Transmission Operator standard requirements not assigned to Generator Operators should always be, never be, or could possibly be assigned to address potential reliability gaps based on the equipment operated by the Generator Operator.
4. Determine if these requirements are already covered by other existing reliability standard requirements.
5. If not, determine a strategy for identifying the functional entity that should be assigned the responsibility for these requirements, not necessarily limited to the current list of functional entities.

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<sup>2</sup> The use of the term “functional entity” is not intended to limit team consideration to those functional entities currently utilized in NERC’s Reliability Standards. If in its deliberation, the team identifies a new functional entity that should be defined; the team can make such a proposal.

<sup>3</sup> The goal is to assign responsibility for these requirements to a single functional entity but recognize that clear delineation of these responsibilities must be identified when multiple entity arrangements apply.

6. Perform sensitivity analyses using the list of “parking lot” questions/issues to determine further activities for the team.
7. Finalize recommendations within a final report that includes potential SARs.


## ***Issues List***

The industry survey that NERC conducted in late 2008 led to the identification of 17 issues for team consideration that are presented below. This list of issues was included in the original proposal that recommended the formation of the team. The team to varying degrees addressed these issues as discussed below, and in several cases, captured the response to related issues in one response. The discussion that follows includes the summary of the team’s deliberation and the rationale for the conclusion the team reached on each issue, and any recommendations that resulted from those discussions. During the course of these discussions, the team carefully separated the impact of the generating unit itself from the impact from the generator’s interconnection facilities. Stated more specifically, the team considered whether there were certain of NERC’s existing Transmission Owner and Transmission Operator requirements that currently do not apply but should apply to the Generator Owner and or Generator Operator by virtue of the interconnection facilities that connect the generating unit to the grid and the various configurations therein. However, the team did not consider the potential loss of energy produced by the generator as a sufficient basis to apply Transmission Owner and or Transmission Operator standards to the generator. In circumstances where improvement to a requirement is needed and is applicable because of the generating plant itself and not because of the interconnection facility, the team identified the needed change and noted it as a generic generator issue. In its resolution of these issues, the team considered the owner requirements apart from the operator requirements.

### **1. Identify what is needed to ensure the reliable supply of real and reactive power to the grid; and determine the goal of the Generator Owner and Generator Operator Requirements (bulk electric system reliability vs. interconnection facility reliability).**

The team concluded that to the extent a generator’s interconnection facilities met the current NERC Glossary Definition as Bulk Electric System, that is, facilities operating above 100 kV or those deemed critical to the reliability of the Bulk Electric System as defined by the Regional Entity, then those facilities are part of the generating facility and are appropriately classified as part of the Bulk Electric System for purposes of applying Generator Owner and Generator Operator requirements, but not for applying Transmission Owner or Transmission Operator Requirements. In this construct, the Generator Owner and Generator Operator has responsibility for the Generator Interconnection Facility (as defined herein) and the Transmission Owner and Transmission Operator has responsibility for the transmission facilities that connect to the Generator Interconnection Facility, and importantly, has operating responsibility for the Generator Interconnection Operational Interface (as defined herein). This approach ensures that no reliability gap exists for the Generator Interconnection Facility. Please continue with the response to Issue 2 for further discussion on the role of Generation Owners and Operators.

### **2. Affect of interconnection configuration on standard requirements and applicability**



The team discussed the varying system configurations that could exist at the generating facility end of the interconnection facility and on the transmission grid side of the interconnection facility. The team quickly concluded that the core issue was the applicability of requirements for sole-use interconnection facilities, that is, those facilities whose singular purpose is to connect the generating facility (inclusive of associated station service load, auxiliary load, or cogeneration load) to the interconnected grid. In this context, facilities such as double circuit lines or the various substation configurations that may exist at the generator facility are included as part of the Generator Interconnection Facility provided their purpose is limited to transmitting power from the plant, provision of station service, auxiliary load requirements, or provision of cogeneration load requirements. For other configurations in which the interconnection facility is used by other parties to tie to other substations or to customer loads or where a generator is connected to multiple transmission facilities of other parties, these facilities are considered integrated for the purposes of standard applicability and the full spectrum of Transmission Owner and Transmission Operator requirements would apply as appropriate.

The team also concluded that an outage of the Generator Interconnection Facility that results in an outage of an integrated transmission line (such as exists in a three-terminal or T-tap configuration) does not provide a sufficient basis for making the Generator Interconnection Facility subject to Transmission Owner and Transmission Operator standard requirements. In fact, the NERC Statement of Compliance Registry Criteria (Revision 5.0) includes an exclusion from registration for “radial transmission facilities serving only load with one transmission source” which would include similar configurations such as T-taps or three-terminal lines. In the case of radial facilities serving only load, the obligations for PRC-type requirements, for example, are included by virtue of the registration as another functional entity besides a Transmission Owner (for instance, as a Distribution Provider assuming the entity meets the Registry criteria for such inclusion). Similarly, Generator Owners that meet the Registry criteria will necessarily be responsible for relevant PRC-type requirements.

Considering sole-use interconnection facilities, the team determined that greater specificity in the current standards is necessary to clearly define and identify Generator Interconnection Facility “as a recognized term and to apply the term where appropriate in certain of the requirements to ensure a clear understanding of expectations. The team therefore proposes below to add a definition of Generator Interconnection Facility to the NERC Glossary and several changes to requirements to include this term. Similarly, the team recommends a proposed new definition and application of the term “Generator Interconnection Operational Interface” in the NERC Glossary and in several standard requirements.

The team also considered various scenarios pertaining to the relationship of the Generator Owner to the Transmission Owner regarding the interconnection facility equipment. If a Generator Owner owns the physical equipment that resides in the Transmission Owner substation at the Generator Interconnection Operational Interface, the team believed that the Generator Owner would not have the independent ability to access or affect the equipment without interfacing with the Transmission Owner; rather, the Generator Owner would necessarily have to coordinate with the Transmission Owner to gain access to the station and work under escort to perform activities on the equipment it owned. As a result, the team

believes that in this scenario, the Generator Owner should not be required to be registered as a Transmission Owner directly.

When viewed at the operational level, considerable discussion ensued regarding the relationship between the Generator Operator and Transmission Operator for operation of the Generator Interconnection Facility, that is, the sole-use interconnection facility. While generally accepted that the Generator Owner owns the Generator Interconnection Facility, the team recognized that the Generator Operator over the facility must use reasonable means to coordinate the operation of that facility in order to preserve the reliability of the grid to which it is interconnected, when the facility is energized and synchronized to the grid or when the interconnection facility is about to be de-energized from or re-energized to the transmission system<sup>4</sup>. The Generator Operator must understand the potential impact to the interconnected transmission system for the actions that they perform on the Generator Interconnection Facility and must therefore be provided focused training for the reliable execution of those responsibilities. Importantly, however, the Transmission Operator to whom the Generator Interconnection Facility interconnects has the decision-making operational authority over the Generator Interconnection Operational Interface.

In response to comments received during the public posting of the initial report, the team also discussed the treatment of the Generator Interconnection Facility of small generators not registered as a Generator Owner and Generator Operator. The team concluded that to the extent that a Regional Entity believes that a small generator and/or its Generator Interconnection Facility is material to the reliability of the Bulk Electric System, it has the right to make such a demonstration and propose registration of the entity as a Generator Owner and Generator Operator. In fact, this report's conclusion that the Generator Interconnection Facility is considered part of the generating facility may benefit 1) the Regional Entity in making a demonstration of materiality as well as 2) the generator if such a demonstration is made. In this regard, the Regional Entity will be able to make its demonstration of materiality on the basis of the generating facility (which includes the Generator Interconnection Facility) instead of having to make separate materiality demonstrations for both the generating unit(s) and the Generator Interconnection Facility. Therefore, if a small generating facility and its Generator Interconnection Facility are demonstrated to be material to the reliability of the Bulk Electric System, they would then be registered as a Generator Owner and Generator Operator and subject to Generator Owner and Generator Operator standards but not subject to Transmission Owner and Transmission Operator standard requirements.

The approach posited in this report acknowledges that the Generator Interconnection Facility, as defined herein, functions for a singular and well-defined purpose, to transmit power to and from the generating plant and for purposes of station service, auxiliary load requirements, or for cogeneration load. As such, these facilities are different in usage than transmission facilities that comprise the interconnected grid. The team carefully reviewed all Transmission Owner requirements for application to the Generator Interconnection Facility and recommend adjustments to several requirements to clarify expectations for the Generator

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<sup>4</sup> Except for situations involving imminent equipment damage or personnel safety for which the Generator Operator may be required to act without coordination with the Transmission Operator.



Owners. Thus, the team believes that these changes ensure consistent expectations at an ownership level. At an operating level, a number of Transmission Operator requirements exist for operating an interconnected transmission grid and a number of closely related Generator Operator requirements are applicable to the Generator Interconnection Facility based on the recommendations contained in this report. Additionally, in a similar fashion to the exclusion provided to radial transmission serving only load in the existing NERC definition of Bulk Electric System and that pertaining to of the inclusion of distribution provider facilities involved in underfrequency load shedding, the Generator Interconnection Facility is proposed to be addressed by NERC standards based on their use. Accordingly, the approach proposed implements a strategy to ensure no gaps in reliability coverage exist relative to the Generator Interconnection Facility. By virtue of the recommendation to process the standard changes using the NERC *Reliability Standard Development Procedure*, the specific approach contained herein will be further vetted with ample opportunity for stakeholder review, input, modification as necessary, and approval before implementation.

### **3. Review GO/GOP and TO/TOP Requirements to identify reliability gaps**

The group spent a significant amount of time reviewing first the Transmission Owner requirements, and then the Transmission Operator requirements currently approved for enforcement but not currently applicable to the Generator Owners or Generator Operators. This bifurcated review carefully considered whether a specific requirement should be made applicable to the Generator Owner or Generator Operator solely on the basis of the Generator Interconnection Facility, and not on the basis of the generator itself. In conducting this review, it became apparent to the team that certain requirements presented a potential reliability gap because the Generator Operator was not listed as an applicable entity based on the generator itself (but not because of its interconnection facility). The team also carefully reviewed the Generator Owner and Generator Operator requirements and concluded that the responsibilities for owning and operating the Generator Interconnection Facility could best be clarified by making certain Generator Owner and Generator Operator requirement language more specific to include the term “Generator Interconnection Facility”. The redline changes to the NERC Standards that highlight these changes are included in **Appendix 1**.

The following description summarizes the proposed standard requirement changes.

- The team identified 32 requirements in which the Generator Interconnection Facility is specifically added to the requirement.
- The team identified 12 requirements in FAC-003-1 – Transmission Vegetation Management that need to include the Generator Owner as an applicable entity based on the conclusions discussed later in the report.
- The team noted 2 requirements whose applicability should be expanded to address generic issues associated with the generating facility and not necessarily with respect to the Generator Interconnection Facility.
- The team identified the need to add 8 new standard requirements to fully clarify the expectations with regard to the Generator Interconnection Facility, heretofore implied in the Standards, or to address certain requirements that should apply to all generators regardless of interconnection configuration as follows.

1. The Generator Operator who has responsibility for monitoring the status of a special protection system or remedial action scheme at the generating facility for the benefit of Bulk Electric System reliability should notify the Transmission Operator when a change in status or capability occurs.
2. Each Generator Operator shall provide its operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Generation Facility and the Generation Interconnection Facility, and to implement directives of the Transmission Operator and Balancing Authority.
3. Each Generator Operator shall implement an initial and continuing training program for all personnel responsible for operating the Generator Interconnection Facility to ensure the ability to operate the equipment in a reliable manner.
4. The Generator Operator shall coordinate the operation of its Generator Interconnection Facility with the Transmission Operator to whom it interconnects to preserve Interconnection reliability.
5. The Transmission Operator has decision-making authority for the Generator Interconnection Operational Interface.
6. The Generator Operator shall notify the Transmission Operator of a change in status of the Generation Interconnection Facility.
7. The Generator Operator shall operate the Generation Interconnection Facility within Facility Ratings.
8. The Generator Operator shall disconnect the Generation Interconnection Facility immediately in coordination with the Transmission Operator when time permits or as soon as practical thereafter if an overload or other abnormal condition threatens equipment or personnel safety.

Regarding item new requirement No. 3, the team does not intend that this requirement results in a need for NERC-certified transmission or generator operators at the generating plant by virtue of the Generator Interconnection Facility. Rather, the training program must contain the necessary elements for the Generator Operator tasked with operating the Generator Interconnection Facility to understand fully the impacts of their operation on the Bulk Electric System, such as equipment involved, including relaying, the coordination aspects with the Transmission Operator to which it is connected, and the protocols for and impacts of operating facilities associated with the Generator Interconnection Facility, including the Generator Interconnection Operational Interface. The objective of this training is to ensure that the Generator Operator is completely aware of its obligations to the Transmission Operators and has the skills and training to execute these obligations in the best interest of reliability.

In completing the review of standard requirements and the determination therein of needed changes, the team concluded that there was no basis for assigning existing Transmission Owner and Transmission Operator standard requirements to the Generator Owner and



Generator Operator, respectively, solely on the basis of the Generator Interconnection Facility, with one exception. The team believes that Standard FAC-003 (Vegetation Management) should apply to Generator Owners of a Generator Interconnection Facility whose facilities operate at 200 kV and above or are otherwise deemed critical to the Bulk Electric System and whose Generation Interconnection Facility exceeds two spans (generally one-half mile from the generator property line). In reaching this conclusion, the team considered other options that included inclusion of Generator Owners as applicable entities to FAC-003 based on a test for criticality, or to include Generator Owners as applicable entities in the existing version of FAC-003 without modification to the applicability criteria. The team, supported by a majority of industry commenters indicated the two-span test presented a simple and objective method to determine responsibilities for Generator Owners. Additionally, the “200 kV and above, or otherwise deemed critical to the Bulk Electric System” threshold is consistent with the current applicability of FAC-003 to Transmission Owners. The rationale for the selection of the two-span criteria is that this distance is in the generator operator’s line-of-sight and as such could be visually monitored for vegetation conditions on a routine basis, and beyond which distance a vegetation management program would be necessary for the Right-of-Way.

In addition regarding the applicability of FAC-003, the group agreed that all units designated as a blackstart resource that are material to and designated as part of the Transmission Operator’s system restoration plan, irrespective of voltage level, are deemed to be critical for purposes of FAC-003 application to the Generator Interconnection Facility, subject to the two-span criterion. To be material, a blackstart unit is defined as a unit that is part of a system restoration plan’s facilities that are used to initiate system restoration and establish the basic minimum power system following a blackout.

#### **4. Defining functional lines of demarcation between the Generator Owner and the Transmission Owner**

The team agrees that the Generator Owner owns the Generator Interconnection Facility and the Transmission Owner owns the facilities of the interconnection grid to which the Generator Interconnection Facility connects. Also agreed is that clear operating responsibility must exist for these facilities. In order to clearly articulate the point at which the change of operation occurs between the Generator Operator and Transmission Operator, the team proposes to add a new definition to the NERC Glossary for Generator Interconnection Operational Interface. The new definition is: location at which operating responsibility for the Generator Interconnection Facility changes from the Transmission Operator and the Generator Operator.

#### **5. Impact of operational control or ownership of equipment in the transmission substation containing the generator interconnection facilities**

This issue is addressed in the Issue 2.

#### **6. Effect of FERC-filed Interconnection Agreements and other agreements between GO/GOP and the TO/TOP**

Depending on the vintage, FERC-filed Interconnection Agreements outline to varying degrees the operating and ownership relationship between the Transmission Provider and the

Interconnection Customer (e.g. Generating Facility). However, the Interconnection Agreements address the expectations for entities under its jurisdiction with respect to different sections of the Federal Power Act than Section 215 that addresses reliability and defines a broader applicability. Therefore, there is an inconsistency in the scope of the entities for which Interconnection Agreements are required and those under Section 215 of the Federal Power Act for reliability purposes. Additionally, the functional entity names in NERC Reliability Standards do not match those terms in the Interconnection Agreements. For these reasons, the effect of Interconnection Agreements on NERC's Standards is debatable.

In addition, NERC's Reliability Standards must contain the requirements necessary to ensure an adequate level of reliability for the Bulk Electric System. It is not appropriate for NERC to rely on other agreements as the primary vehicle to define reliability obligations. Thus, while the Interconnection Agreements may define greater specificity as to how certain reliability-related activities are expected to be conducted, NERC Reliability Standards must contain what is required from a performance outcome. The team has evaluated the current set of requirements to validate that the necessary requirements are in place; and to the extent improvements or additions are needed, identified those modifications or new obligations.

#### **7. Bifurcated review of GO Requirements and GOP Requirements**

The team agreed that it is necessary and appropriate to consider the Generator Owner Requirements distinct from the Generator Operator requirements as discussed in Issue 3.

#### **8. Review NERC Glossary definitions for Transmission, Generator Owner, Generator Operator, Transmission Owner, and Transmission Operator**

The team reviewed the definitions listed in the NERC Glossary of Terms and considered additional terms as they impacted the intent and meaning of certain requirements currently applicable to the Transmission Operator or Transmission Owner. The team believed that modifications to some and additions of several new terms were needed to add greater clarity to the applicability of requirements pertaining to the generator interconnection facilities.

- Transmission — the team agreed with the existing definition but determined it necessary to add a sentence to specify that the Generator Interconnection Facility is not part of the definition. The proposed definition with the modification italicized is as follows:

##### **Transmission**

An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

*Generator Interconnection Facility is not included in this definition.*

- Generator Owner — the team agreed with the existing definition but determined it necessary to add a phrase that specifies the inclusion of the generator's interconnection facilities. The proposed definition is as follows:

### **Generator Owner**

Entity that owns and maintains generating units, *including its Generator Interconnection Facility*

- Generator Operator — the team agreed with the existing definition but determined it necessary to add a sentence to indicate that operational coordination was necessary with the Transmission Operator for the Generator Interconnection Facility. With the modification italicized, the proposed definition is:

### **Generator Operator**

The entity that operates generating unit(s) and the Generator Interconnection Facility and performs the functions of supplying energy and Interconnected Operations Services. *The Generator Operator also operates the Generator Interconnection Facility and is responsible for coordinating with the Transmission Operator when the facility is energized or about to be energized to/de-energized from the transmission system.*

- Transmission Owner — no changes are necessary
- Transmission Operator — no changes are necessary

The team also considered the terms, Transmission Line, Element, Facility, Interconnection, and System and do not recommend changes to these terms. Further, the team recommends improvements to the terms, Right-of-Way and Vegetation Inspection to encompass the Generator Interconnection Facility, and proposes two new terms, Generator Interconnection Facility and Generator Interconnection Operational Interface as follows:

### **Right-of-Way (ROW)**

A corridor of land on which electric lines may be located. ~~The Transmission Owner~~ *owner of the electric lines* may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

### **Vegetation Inspection**

The systematic examination of a ~~transmission corridor~~ *Transmission Line or Generator Interconnection Facility Right-of-Way* to document vegetation conditions.

### **Generator Interconnection Facility (NEW)**

*Sole-use facility for the purpose of connecting the generating unit(s) to the transmission grid. In this regard, the sole-use facility only transmits power associated with the interconnecting generator, whether delivered to the grid or delivered to the generator for station service or auxiliary load, or delivered to meet cogeneration load requirements.*

### **Generator Interconnection Operational Interface (NEW)**

*Location at which operating responsibility for the Generator Interconnection Facility changes between the Transmission Operator and the Generator Operator.*

These terms will be incorporated as recommended changes to existing standard requirements through the standards authorization requests contained in Appendix C.

## **9. NERC Compliance Registry Guidance**

The team identified that companion changes to NERC's Statement of Compliance Registry are required to incorporate the changes to the definitions for Generator Owner and Generator Operator proposed by the group. As outlined in Exhibit B, specific modifications are required in Section II of the document with respect to the definitions of Generator Owner and Generator Operator as proposed in this report. Additional changes are necessary in Section III.c.4 and III.d.2 to provide the proposed definition of Generator Interconnection Facility and to specify that the Generator Interconnection Facility is considered part of the generating facility and not the integrated transmission system for purposes of applying the registry criteria.

In addition, the group believes it appropriate to include definitive statements such that it is clear that a Generator Owner or Generator Operator should not be registered as a Transmission Owner or Transmission Operator, respectively, solely resulting from the Generator Interconnection Facility as defined herein. These modifications will ensure consistency in application of the NERC Reliability Standards to those Generator Owners identified through implementation of the NERC Compliance Registry processes.

In addition, NERC and the Regional Entities should carefully develop and implement a plan to address de-registering those Generator Owners and Generator Operators that have previously been registered as a Transmission Owner and Transmission Operator by virtue of the Generator Interconnection Facility. The team recognizes that Regional Entities have discretion to determine critical facilities within its footprint in individual case-by-case assessments.

## **10. Material Impact Test for Generator Interconnection Facilities**

The group concluded that only one existing Reliability Standard that is applicable to Transmission Owners, FAC-003-1, should have its applicability expanded to Generator Owners because of their Generator Interconnection Facility. Although the two-span test noted in Proposal 2 was selected as the most appropriate approach, the following list contains a summary of the three proposals that were considered:

**Proposal 1** — A straightforward criterion suggested is to apply FAC-003-1 for the Generator Interconnection Facility per the current standard's applicability.

**Proposal 2** — A second proposal is based on Proposal 1 but provides an exclusion for short distance Rights-of-Way that are generally within line of sight from the generating plant. This proposal calls for applying FAC-003-1 for the Generator Interconnection Facility operating above 200 kV that extend beyond two tower spans (i.e. ½ mile) from the generating plant property line.

**Proposal 3** — A third proposal applies FAC-003-1 to the Generator Interconnection Facility that operates at 200 kV or above and that is deemed critical to the Bulk Electric System. In

this regard, the criticality test as discussed by the team would be the following: the Generator Owner would coordinate with the Transmission Planner to perform an impact based test utilizing similar criteria to that outlined in TPL-003-0 Table 1 Category C that assesses system performance under scenarios involving more than one contingency event.

Particularly, the team agreed that the engineering analysis would be based on the system performance expectations of a single-line-to-ground fault on the interconnection facility with delayed clearing or a stuck breaker. Under these conditions, the criticality test would be met if the system response to these contingency events resulted in cascading outages, system instability, or operating outside applicable ratings, with loss of firm load or the curtailment of third-party firm transfers that is not associated with the loss of the generating plant output directly connected to the Generator Interconnection Facility against which the originating contingency was applied.

The team ultimately relied on additional input received from industry stakeholders during the comment opportunity to guide its conclusion in this area. Based on the simplicity and objectiveness of approach, a large number of commenters indicated a preference for Proposal 2. While the criticality test was supported by some, most expressed concern regarding the resource commitment for analysis and the subjectivity of the approach.

**11. Functionality test — Does the facility function as part of the generator function or the transmission function**

Because the generator owns the Generator Interconnection Facility, the team decided that a Generator Interconnection Facility is considered part of the generator facility. For clarity, a number of standard requirement modifications or additions are recommended to ensure that the Generator Interconnection Facility is appropriately considered and that clear responsibility for ownership and operation are established by those identified as having these obligations.

**12. Approach for multi-unit plants interconnected through a single transmission line**

The team considered this issue and supported its earlier determination that a sole-use interconnection facility should not in and of itself require a Generator Owner and Generator Operator to be registered as a Transmission Owner and Transmission Operator.

**13. Generic application of requirements versus a case-by-case determination**

The team determined that through addition or modification of certain standard requirements, there is no reliability gap by virtue of the Generator Interconnection Facility with one exception: FAC-003-1 pertaining to transmission vegetation management. The team determined that FAC-003-1 standard should apply to Generator Owners for facilities operating above 200 kV or otherwise deemed critical to the Bulk Electric System if the Generation Interconnection Facility exceeds two-spans, generally one-half mile, from the generator property line. Otherwise, the standards as modified provide the ability to generically apply the standard requirements to all Generator Owners and Generator Operators without introducing or perpetuating any perceived reliability gaps.

**14. Affect on the applicability if generators provide ancillary services (reactive control, regulation, reserves, etc.)**

This issue is addressed previously and is at the discretion of Regional Entities in application of the definition of Bulk Electric System.

**15. Consideration of generators that are included in:**

- special protection scheme or remedial action scheme
- coordinated underfrequency program
- coordinated undervoltage program
- blackstart
- SOL or IROL limits
- Provision of firm energy

This issue is addressed previously and is at the discretion of Regional Entities in application of the definition of Bulk Electric System.

**16. Need for additional maintenance-based generator owner requirements on interconnection facilities when generators already are financially incented to remain available**

The team concluded that to the extent a generator's interconnection facilities meet the current NERC Glossary Definition as Bulk Electric System, that is, facilities operating above 100 kV or those deemed critical to the reliability of the Bulk Electric System as defined by the Regional Entity, then those facilities are appropriately classified as part of the Bulk Electric System for purposes of applying Generator Owner and Generator Operator requirements but not for applying Transmission Owner or Transmission Operator requirements. For interconnection facilities classified as such, an entity must be designated to be responsible for relevant ownership and operation obligations. These obligations manifest themselves as requirements in the Reliability Standards to ensure an adequate level of reliability is maintained on the Bulk Electric System. Therefore, specification of ownership and operational requirements for a Generator Interconnection Facility is necessary to ensure the expected performance is achieved consistent with the reliability objectives being sought. While the statement is undoubtedly true that generators, including its interconnection facilities, are motivated to remain available to be capable of delivering energy (and capacity) to the grid, these self-directed motivations do not adequately assure that the obligations for reliability of the Bulk Electric System will be supported under all circumstances. Developing NERC Reliability Standard requirements to address these expectations further incent the Generator Owner and Generator Operator to execute their responsibilities consistent with NERC's reliability obligations.

**17. Develop new transmission functional category know as Generator-Tie**

The team considered whether the addition of a new Generator-Tie functional category would add the clarity needed to ensure that standard requirements applicable to generator interconnection facilities would result in no reliability gaps. Upon reflection, the team determined that it could achieve the intended purpose through the inclusion the modified and new definitions proposed, and their application to the existing standard requirements. This would result in significantly less effort to implement in the standards, greater industry acceptance, and thus a shorter timeframe to implement on the whole.



# **Appendix 1 — Review of NERC Reliability Standards Requirements**



Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
BAL-005-0.1b	R1.	All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.		GOP		TOP	
BAL-005-0.1b	R1.1.	Each Generator Operator with generation facilities, <a href="#">including its Generator Interconnection Facility</a> , operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.		GOP			
BAL-005-0.1b	R1.2.	Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.				TOP	
CIP-001-1	R1.	Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity shall have procedures for the recognition of and for making their operating personnel aware of sabotage events on its facilities and multi site sabotage affecting larger portions of the Interconnection.		GOP		TOP	
CIP-001-1	R2.	Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity shall have procedures for the communication of information concerning sabotage events to appropriate parties in the Interconnection.		GOP		TOP	
CIP-001-1	R3.	Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity shall provide its operating personnel with sabotage response guidelines, including personnel to contact, for reporting disturbances due to sabotage events.		GOP		TOP	
CIP-001-1	R4.	Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity shall establish communications contacts, as applicable, with local Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP) officials and develop		GOP		TOP	



Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		reporting procedures as appropriate to their circumstances.					
CIP-002-1	R1.	Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.	GO	GOP	TO	TOP	
CIP-002-1	R1.1.	The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.	GO	GOP	TO	TOP	
CIP-002-1	R1.2.	The risk-based assessment shall consider the following assets:	GO	GOP	TO	TOP	
CIP-002-1	R1.2.1.	Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.	GO	GOP	TO	TOP	
CIP-002-1	R1.2.2.	Transmission substations that support the reliable operation of the Bulk Electric System.	GO	GOP	TO	TOP	
CIP-002-1	R1.2.3.	Generation resources, <a href="#">including the Generator Interconnection Facility</a> , that support the reliable operation of the Bulk Electric System.	GO	GOP	TO	TOP	
CIP-002-1	R1.2.4.	Systems and facilities critical to system restoration, including blackstart generators <a href="#">and their attendant Generator Interconnection Facility</a> , and substations in the electrical path of transmission lines used for initial system restoration.	GO	GOP	TO	TOP	
CIP-002-1	R1.2.5.	Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.	GO	GOP	TO	TOP	
CIP-002-1	R1.2.6.	Special Protection Systems that support the reliable operation of the Bulk Electric System.	GO	GOP	TO	TOP	
CIP-002-1	R1.2.7.	Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-002-1	R2.	Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.	GO	GOP	TO	TOP	
CIP-002-1	R3.	Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:	GO	GOP	TO	TOP	
CIP-002-1	R3.1.	The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,	GO	GOP	TO	TOP	
CIP-002-1	R3.2.	The Cyber Asset uses a routable protocol within a control center; or,	GO	GOP	TO	TOP	
CIP-002-1	R3.3.	The Cyber Asset is dial-up accessible.	GO	GOP	TO	TOP	
CIP-002-1	R4.	Annual Approval — A senior manager or delegate(s) shall approve annually the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of the senior manager or delegate(s)'s approval of the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-003-1	R1.	Cyber Security Policy — The Responsible Entity shall document and implement a cyber security policy that represents management’s commitment and ability to secure its Critical Cyber Assets. The Responsible Entity shall, at minimum, ensure the following:	GO	GOP	TO	TOP	
CIP-003-1	R1.1.	The cyber security policy addresses the requirements in Standards CIP-002 through CIP-009, including provision for emergency situations.	GO	GOP	TO	TOP	
CIP-003-1	R1.2.	The cyber security policy is readily available to all personnel who have access to, or are responsible for, Critical Cyber Assets.	GO	GOP	TO	TOP	
CIP-003-1	R1.3.	Annual review and approval of the cyber security policy by the senior manager assigned pursuant to R2.	GO	GOP	TO	TOP	
CIP-003-1	R2.	Leadership — The Responsible Entity shall assign a senior manager with overall responsibility for leading and managing the entity’s implementation of, and adherence to, Standards CIP-002 through CIP-009	GO	GOP	TO	TOP	
CIP-003-1	R2.1.	The senior manager shall be identified by name, title, business phone, business address, and date of designation.	GO	GOP	TO	TOP	
CIP-003-1	R2.2.	Changes to the senior manager must be documented within thirty calendar days of the effective date.	GO	GOP	TO	TOP	
CIP-003-1	R2.3.	The senior manager or delegate(s), shall authorize and document any exception from the requirements of the cyber security policy.	GO	GOP	TO	TOP	
CIP-003-1	R3.	Exceptions — Instances where the Responsible Entity cannot conform to its cyber security policy must be documented as exceptions and authorized by the senior manager or delegate(s).	GO	GOP	TO	TOP	
CIP-003-1	R3.1.	Exceptions to the Responsible Entity’s cyber security policy must be documented within thirty days of being approved by the senior manager or delegate(s).	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-003-1	R3.2.	Documented exceptions to the cyber security policy must include an explanation as to why the exception is necessary and any compensating measures, or a statement accepting risk.	GO	GOP	TO	TOP	
CIP-003-1	R3.3.	Authorized exceptions to the cyber security policy must be reviewed and approved annually by the senior manager or delegate(s) to ensure the exceptions are still required and valid. Such review and approval shall be documented.	GO	GOP	TO	TOP	
CIP-003-1	R4.	Information Protection — The Responsible Entity shall implement and document a program to identify, classify, and protect information associated with Critical Cyber Assets.	GO	GOP	TO	TOP	
CIP-003-1	R4.1.	The Critical Cyber Asset information to be protected shall include, at a minimum and regardless of media type, operational procedures, lists as required in Standard CIP-002, network topology or similar diagrams, floor plans of computing centers that contain Critical Cyber Assets, equipment layouts of Critical Cyber Assets, disaster recovery plans, incident response plans, and security configuration information.	GO	GOP	TO	TOP	
CIP-003-1	R4.2.	The Responsible Entity shall classify information to be protected under this program based on the sensitivity of the Critical Cyber Asset information.	GO	GOP	TO	TOP	
CIP-003-1	R4.3.	The Responsible Entity shall, at least annually, assess adherence to its Critical Cyber Asset information protection program, document the assessment results, and implement an action plan to remediate deficiencies identified during the assessment.	GO	GOP	TO	TOP	
CIP-003-1	R5.	Access Control — The Responsible Entity shall document and implement a program for managing access to protected Critical Cyber Asset information.	GO	GOP	TO	TOP	
CIP-003-1	R5.1.	The Responsible Entity shall maintain a list of designated personnel who are responsible for authorizing logical or physical access to protected information.	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-003-1	R5.1.1.	Personnel shall be identified by name, title, business phone and the information for which they are responsible for authorizing access.	GO	GOP	TO	TOP	
CIP-003-1	R5.1.2.	The list of personnel responsible for authorizing access to protected information shall be verified at least annually.	GO	GOP	TO	TOP	
CIP-003-1	R5.2.	The Responsible Entity shall review at least annually the access privileges to protected information to confirm that access privileges are correct and that they correspond with the Responsible Entity's needs and appropriate personnel roles and responsibilities.	GO	GOP	TO	TOP	
CIP-003-1	R5.3.	The Responsible Entity shall assess and document at least annually the processes for controlling access privileges to protected information.	GO	GOP	TO	TOP	
CIP-003-1	R6.	Change Control and Configuration Management — The Responsible Entity shall establish and document a process of change control and configuration management for adding, modifying, replacing, or removing Critical Cyber Asset hardware or software, and implement supporting configuration management activities to identify, control and document all entity or vendor related changes to hardware and software components of Critical Cyber Assets pursuant to the change control process.	GO	GOP	TO	TOP	
CIP-004-1	R1.	Awareness — The Responsible Entity shall establish, maintain, and document a security awareness program to ensure personnel having authorized cyber or authorized unescorted physical access receive on-going reinforcement in sound security practices. The program shall include security awareness reinforcement on at least a quarterly basis using mechanisms such as: Direct communications (e.g., emails, memos, computer based training, etc.); Indirect communications (e.g., posters, intranet, brochures, etc.); Management support and reinforcement (e.g., presentations, meetings, etc.).	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-004-1	R2.	Training — The Responsible Entity shall establish, maintain, and document an annual cyber security training program for personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets, and review the program annually and update as necessary.	GO	GOP	TO	TOP	
CIP-004-1	R2.1.	This program will ensure that all personnel having such access to Critical Cyber Assets, including contractors and service vendors, are trained within ninety calendar days of such authorization.	GO	GOP	TO	TOP	
CIP-004-1	R2.2.	Training shall cover the policies, access controls, and procedures as developed for the Critical Cyber Assets covered by CIP-004, and include, at a minimum, the following required items appropriate to personnel roles and responsibilities:	GO	GOP	TO	TOP	
CIP-004-1	R2.2.1.	The proper use of Critical Cyber Assets;	GO	GOP	TO	TOP	
CIP-004-1	R2.2.2.	Physical and electronic access controls to Critical Cyber Assets;	GO	GOP	TO	TOP	
CIP-004-1	R2.2.3.	The proper handling of Critical Cyber Asset information; and,	GO	GOP	TO	TOP	
CIP-004-1	R2.2.4.	Action plans and procedures to recover or re-establish Critical Cyber Assets and access thereto following a Cyber Security Incident.	GO	GOP	TO	TOP	
CIP-004-1	R2.3.	The Responsible Entity shall maintain documentation that training is conducted at least annually, including the date the training was completed and attendance records.	GO	GOP	TO	TOP	
CIP-004-1	R3.	Personnel Risk Assessment —The Responsible Entity shall have a documented personnel risk assessment program, in accordance with federal, state, provincial, and local laws, and subject to existing collective bargaining unit agreements, for personnel having authorized cyber or authorized unescorted physical access. A personnel risk assessment shall be conducted pursuant to that program within thirty days of such personnel being granted such access. Such program shall at a minimum include:	GO	GOP	TO	TOP	
CIP-004-1	R3.1.	The Responsible Entity shall ensure that each assessment	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		conducted include, at least, identity verification (e.g., Social Security Number verification in the U.S.) and seven year criminal check. The Responsible Entity may conduct more detailed reviews, as permitted by law and subject to existing collective bargaining unit agreements, depending upon the criticality of the position.					
CIP-004-1	R3.2.	The Responsible Entity shall update each personnel risk assessment at least every seven years after the initial personnel risk assessment or for cause.	GO	GOP	TO	TOP	
CIP-004-1	R3.3.	The Responsible Entity shall document the results of personnel risk assessments of its personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets, and that personnel risk assessments of contractor and service vendor personnel with such access are conducted pursuant to Standard CIP-004.	GO	GOP	TO	TOP	
CIP-004-1	R4.	Access — The Responsible Entity shall maintain list(s) of personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including their specific electronic and physical access rights to Critical Cyber Assets.	GO	GOP	TO	TOP	
CIP-004-1	R4.1.	The Responsible Entity shall review the list(s) of its personnel who have such access to Critical Cyber Assets quarterly, and update the list(s) within seven calendar days of any change of personnel with such access to Critical Cyber Assets, or any change in the access rights of such personnel. The Responsible Entity shall ensure access list(s) for contractors and service vendors are properly maintained.	GO	GOP	TO	TOP	
CIP-004-1	R4.2.	The Responsible Entity shall revoke such access to Critical Cyber Assets within 24 hours for personnel terminated for cause and within seven calendar days for personnel who no longer require such access to Critical Cyber Assets.	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-005-1	R1.	Electronic Security Perimeter — The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The Responsible Entity shall identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s).	GO	GOP	TO	TOP	
CIP-005-1	R1.1.	Access points to the Electronic Security Perimeter(s) shall include any externally connected communication end point (for example, dial-up modems) terminating at any device within the Electronic Security Perimeter(s).	GO	GOP	TO	TOP	
CIP-005-1	R1.2.	For a dial-up accessible Critical Cyber Asset that uses a non-routable protocol, the Responsible Entity shall define an Electronic Security Perimeter for that single access point at the dial-up device.	GO	GOP	TO	TOP	
CIP-005-1	R1.3.	Communication links connecting discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However, end points of these communication links within the Electronic Security Perimeter(s) shall be considered access points to the Electronic Security Perimeter(s).	GO	GOP	TO	TOP	
CIP-005-1	R1.4.	Any non-critical Cyber Asset within a defined Electronic Security Perimeter shall be identified and protected pursuant to the requirements of Standard CIP-005.	GO	GOP	TO	TOP	
CIP-005-1	R1.5.	Cyber Assets used in the access control and monitoring of the Electronic Security Perimeter(s) shall be afforded the protective measures as a specified in Standard CIP-003, Standard CIP-004 Requirement R3, Standard CIP-005 Requirements R2 and R3, Standard CIP-006 Requirements R2 and R3, Standard CIP-007, Requirements R1 and R3 through R9, Standard CIP-008, and Standard CIP-009.	GO	GOP	TO	TOP	



Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-005-1	R1.6.	The Responsible Entity shall maintain documentation of Electronic Security Perimeter(s), all interconnected Critical and non-critical Cyber Assets within the Electronic Security Perimeter(s), all electronic access points to the Electronic Security Perimeter(s) and the Cyber Assets deployed for the access control and monitoring of these access points.	GO	GOP	TO	TOP	
CIP-005-1	R2.	Electronic Access Controls — The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for control of electronic access at all electronic access points to the Electronic Security Perimeter(s).	GO	GOP	TO	TOP	
CIP-005-1	R2.1.	These processes and mechanisms shall use an access control model that denies access by default, such that explicit access permissions must be specified.	GO	GOP	TO	TOP	
CIP-005-1	R2.2.	At all access points to the Electronic Security Perimeter(s), the Responsible Entity shall enable only ports and services required for operations and for monitoring Cyber Assets within the Electronic Security Perimeter, and shall document, individually or by specified grouping, the configuration of those ports and services.	GO	GOP	TO	TOP	
CIP-005-1	R2.3.	The Responsible Entity shall maintain a procedure for securing dial-up access to the Electronic Security Perimeter(s).	GO	GOP	TO	TOP	
CIP-005-1	R2.4.	Where external interactive access into the Electronic Security Perimeter has been enabled, the Responsible Entity shall implement strong procedural or technical controls at the access points to ensure authenticity of the accessing party, where technically feasible.	GO	GOP	TO	TOP	
CIP-005-1	R2.5.	The required documentation shall, at least, identify and describe:	GO	GOP	TO	TOP	
CIP-005-1	R2.5.1.	The processes for access request and authorization.	GO	GOP	TO	TOP	
CIP-005-1	R2.5.2.	The authentication methods.	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-005-1	R2.5.3.	The review process for authorization rights, in accordance with Standard CIP-004 Requirement R4.	GO	GOP	TO	TOP	
CIP-005-1	R2.5.4.	The controls used to secure dial-up accessible connections.	GO	GOP	TO	TOP	
CIP-005-1	R2.6.	Appropriate Use Banner — Where technically feasible, electronic access control devices shall display an appropriate use banner on the user screen upon all interactive access attempts. The Responsible Entity shall maintain a document identifying the content of the banner.	GO	GOP	TO	TOP	
CIP-005-1	R3.	Monitoring Electronic Access — The Responsible Entity shall implement and document an electronic or manual process(es) for monitoring and logging access at access points to the Electronic Security Perimeter(s) twenty-four hours a day, seven days a week.	GO	GOP	TO	TOP	
CIP-005-1	R3.1.	For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall implement and document monitoring process(es) at each access point to the dial-up device, where technically feasible.	GO	GOP	TO	TOP	
CIP-005-1	R3.2.	Where technically feasible, the security monitoring process(es) shall detect and alert for attempts at or actual unauthorized accesses. These alerts shall provide for appropriate notification to designated response personnel. Where alerting is not technically feasible, the Responsible Entity shall review or otherwise assess access logs for attempts at or actual unauthorized accesses at least every ninety calendar days.	GO	GOP	TO	TOP	
CIP-005-1	R4.	Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of the electronic access points to the Electronic Security Perimeter(s) at least annually. The vulnerability assessment shall include, at a minimum, the following:	GO	GOP	TO	TOP	
CIP-005-1	R4.1.	A document identifying the vulnerability assessment process;	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-005-1	R4.2.	A review to verify that only ports and services required for operations at these access points are enabled;	GO	GOP	TO	TOP	
CIP-005-1	R4.3.	The discovery of all access points to the Electronic Security Perimeter;	GO	GOP	TO	TOP	
CIP-005-1	R4.4.	A review of controls for default accounts, passwords, and network management community strings; and,	GO	GOP	TO	TOP	
CIP-005-1	R4.5.	Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.	GO	GOP	TO	TOP	
CIP-005-1	R5.	Documentation Review and Maintenance — The Responsible Entity shall review, update, and maintain all documentation to support compliance with the requirements of Standard CIP-005.	GO	GOP	TO	TOP	
CIP-005-1	R5.1.	The Responsible Entity shall ensure that all documentation required by Standard CIP-005 reflect current configurations and processes and shall review the documents and procedures referenced in Standard CIP-005 at least annually.	GO	GOP	TO	TOP	
CIP-005-1	R5.2.	The Responsible Entity shall update the documentation to reflect the modification of the network or controls within ninety calendar days of the change.	GO	GOP	TO	TOP	
CIP-005-1	R5.3.	The Responsible Entity shall retain electronic access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008.	GO	GOP	TO	TOP	
CIP-006-1	R1.	Physical Security Plan — The Responsible Entity shall create and maintain a physical security plan, approved by a senior manager or delegate(s) that shall address, at a minimum, the following:	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-006-1	R1.1.	Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed (“six-wall”) border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.	GO	GOP	TO	TOP	
CIP-006-1	R1.2.	Processes to identify all access points through each Physical Security Perimeter and measures to control entry at those access points.	GO	GOP	TO	TOP	
CIP-006-1	R1.3.	Processes, tools, and procedures to monitor physical access to the perimeter(s).	GO	GOP	TO	TOP	
CIP-006-1	R1.4.	Procedures for the appropriate use of physical access controls as described in Requirement R3 including visitor pass management, response to loss, and prohibition of inappropriate use of physical access controls.	GO	GOP	TO	TOP	
CIP-006-1	R1.5.	Procedures for reviewing access authorization requests and revocation of access authorization, in accordance with CIP-004 Requirement R4.	GO	GOP	TO	TOP	
CIP-006-1	R1.6.	Procedures for escorted access within the physical security perimeter of personnel not authorized for unescorted access.	GO	GOP	TO	TOP	
CIP-006-1	R1.7.	Process for updating the physical security plan within ninety calendar days of any physical security system redesign or reconfiguration, including, but not limited to, addition or removal of access points through the physical security perimeter, physical access controls, monitoring controls, or logging controls.	GO	GOP	TO	TOP	
CIP-006-1	R1.8.	Cyber Assets used in the access control and monitoring of the Physical Security Perimeter(s) shall be afforded the protective measures specified in Standard CIP-003, Standard CIP-004 Requirement R3, Standard CIP-005 Requirements R2 and R3, Standard CIP-006 Requirement R2 and R3, Standard CIP-007, Standard CIP-008 and Standard CIP-009.	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-006-1	R1.9.	Process for ensuring that the physical security plan is reviewed at least annually.	GO	GOP	TO	TOP	
CIP-006-1	R2.	Physical Access Controls — The Responsible Entity shall document and implement the operational and procedural controls to manage physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. The Responsible Entity shall implement one or more of the following physical access methods:	GO	GOP	TO	TOP	
CIP-006-1	R2.1.	Card Key: A means of electronic access where the access rights of the card holder are predefined in a computer database. Access rights may differ from one perimeter to another.	GO	GOP	TO	TOP	
CIP-006-1	R2.2.	Special Locks: These include, but are not limited to, locks with “restricted key” systems, magnetic locks that can be operated remotely, and “man-trap” systems.	GO	GOP	TO	TOP	
CIP-006-1	R2.3.	Security Personnel: Personnel responsible for controlling physical access who may reside on-site or at a monitoring station.	GO	GOP	TO	TOP	
CIP-006-1	R2.4.	Other Authentication Devices: Biometric, keypad, token, or other equivalent devices that control physical access to the Critical Cyber Assets.	GO	GOP	TO	TOP	
CIP-006-1	R3.	Monitoring Physical Access — The Responsible Entity shall document and implement the technical and procedural controls for monitoring physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. Unauthorized access attempts shall be reviewed immediately and handled in accordance with the procedures specified in Requirement CIP-008. One or more of the following monitoring methods shall be used:	GO	GOP	TO	TOP	
CIP-006-1	R3.1.	Alarm Systems: Systems that alarm to indicate a door, gate or window has been opened without authorization. These alarms must provide for immediate notification to personnel responsible for response.	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-006-1	R3.2.	Human Observation of Access Points: Monitoring of physical access points by authorized personnel as specified in Requirement R2.3.	GO	GOP	TO	TOP	
CIP-006-1	R4.	Logging Physical Access — Logging shall record sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a week. The Responsible Entity shall implement and document the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent:	GO	GOP	TO	TOP	
CIP-006-1	R4.1.	Computerized Logging: Electronic logs produced by the Responsible Entity's selected access control and monitoring method.	GO	GOP	TO	TOP	
CIP-006-1	R4.2.	Video Recording: Electronic capture of video images of sufficient quality to determine identity.	GO	GOP	TO	TOP	
CIP-006-1	R4.3.	Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access as specified in Requirement R2.3.	GO	GOP	TO	TOP	
CIP-006-1	R5.	Access Log Retention — The Responsible Entity shall retain physical access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008.	GO	GOP	TO	TOP	
CIP-006-1	R6.	Maintenance and Testing — The Responsible Entity shall implement a maintenance and testing program to ensure that all physical security systems under Requirements R2, R3, and R4 function properly. The program must include, at a minimum, the following:	GO	GOP	TO	TOP	
CIP-006-1	R6.1.	Testing and maintenance of all physical security mechanisms on a cycle no longer than three years.	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-006-1	R6.2.	Retention of testing and maintenance records for the cycle determined by the Responsible Entity in Requirement R6.1.	GO	GOP	TO	TOP	
CIP-006-1	R6.3.	Retention of outage records regarding access controls, logging, and monitoring for a minimum of one calendar year.	GO	GOP	TO	TOP	
CIP-007-1	R1.	Test Procedures — The Responsible Entity shall ensure that new Cyber Assets and significant changes to existing Cyber Assets within the Electronic Security Perimeter do not adversely affect existing cyber security controls. For purposes of Standard CIP-007, a significant change shall, at a minimum, include implementation of security patches, cumulative service packs, vendor releases, and version upgrades of operating systems, applications, database platforms, or other third-party software or firmware.	GO	GOP	TO	TOP	
CIP-007-1	R1.1.	The Responsible Entity shall create, implement, and maintain cyber security test procedures in a manner that minimizes adverse effects on the production system or its operation.	GO	GOP	TO	TOP	
CIP-007-1	R1.2.	The Responsible Entity shall document that testing is performed in a manner that reflects the production environment.	GO	GOP	TO	TOP	
CIP-007-1	R1.3.	The Responsible Entity shall document test results.	GO	GOP	TO	TOP	
CIP-007-1	R2.	Ports and Services — The Responsible Entity shall establish and document a process to ensure that only those ports and services required for normal and emergency operations are enabled.	GO	GOP	TO	TOP	
CIP-007-1	R2.1.	The Responsible Entity shall enable only those ports and services required for normal and emergency operations.	GO	GOP	TO	TOP	
CIP-007-1	R2.2.	The Responsible Entity shall disable other ports and services, including those used for testing purposes, prior to production use of all Cyber Assets inside the Electronic Security Perimeter(s).	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-007-1	R2.3.	In the case where unused ports and services cannot be disabled due to technical limitations, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure or an acceptance of risk.	GO	GOP	TO	TOP	
CIP-007-1	R3.	Security Patch Management — The Responsible Entity, either separately or as a component of the documented configuration management process specified in CIP-003 Requirement R6, shall establish and document a security patch management program for tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).	GO	GOP	TO	TOP	
CIP-007-1	R3.1.	The Responsible Entity shall document the assessment of security patches and security upgrades for applicability within thirty calendar days of availability of the patches or upgrades.	GO	GOP	TO	TOP	
CIP-007-1	R3.2.	The Responsible Entity shall document the implementation of security patches. In any case where the patch is not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure or an acceptance of risk.	GO	GOP	TO	TOP	
CIP-007-1	R4.	Malicious Software Prevention — The Responsible Entity shall use anti-virus software and other malicious software (“malware”) prevention tools, where technically feasible, to detect, prevent, deter, and mitigate the introduction, exposure, and propagation of malware on all Cyber Assets within the Electronic Security Perimeter(s).	GO	GOP	TO	TOP	
CIP-007-1	R4.1.	The Responsible Entity shall document and implement anti-virus and malware prevention tools. In the case where anti-virus software and malware prevention tools are not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure or an acceptance of risk.	GO	GOP	TO	TOP	
CIP-007-1	R4.2.	The Responsible Entity shall document and implement a process for the update of anti-virus and malware prevention “signatures.” The process must address testing and installing the signatures.	GO	GOP	TO	TOP	



Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-007-1	R5.	Account Management — The Responsible Entity shall establish, implement, and document technical and procedural controls that enforce access authentication of, and accountability for, all user activity, and that minimize the risk of unauthorized system access.	GO	GOP	TO	TOP	
CIP-007-1	R5.1.	The Responsible Entity shall ensure that individual and shared system accounts and authorized access permissions are consistent with the concept of “need to know” with respect to work functions performed.	GO	GOP	TO	TOP	
CIP-007-1	R5.1.1.	The Responsible Entity shall ensure that user accounts are implemented as approved by designated personnel. Refer to Standard CIP-003 Requirement R5.	GO	GOP	TO	TOP	
CIP-007-1	R5.1.2.	The Responsible Entity shall establish methods, processes, and procedures that generate logs of sufficient detail to create historical audit trails of individual user account access activity for a minimum of ninety days.	GO	GOP	TO	TOP	
CIP-007-1	R5.1.3.	The Responsible Entity shall review, at least annually, user accounts to verify access privileges are in accordance with Standard CIP-003 Requirement R5 and Standard CIP-004 Requirement R4.	GO	GOP	TO	TOP	
CIP-007-1	R5.2.	The Responsible Entity shall implement a policy to minimize and manage the scope and acceptable use of administrator, shared, and other generic account privileges including factory default accounts.	GO	GOP	TO	TOP	
CIP-007-1	R5.2.1.	The policy shall include the removal, disabling, or renaming of such accounts where possible. For such accounts that must remain enabled, passwords shall be changed prior to putting any system into service.	GO	GOP	TO	TOP	
CIP-007-1	R5.2.2.	The Responsible Entity shall identify those individuals with access to shared accounts.	GO	GOP	TO	TOP	
CIP-007-1	R5.2.3.	Where such accounts must be shared, the Responsible Entity shall have a policy for managing the use of such accounts that	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		limits access to only those with authorization, an audit trail of the account use (automated or manual), and steps for securing the account in the event of personnel changes (for example, change in assignment or termination).					
CIP-007-1	R5.3.	At a minimum, the Responsible Entity shall require and use passwords, subject to the following, as technically feasible:	GO	GOP	TO	TOP	
CIP-007-1	R5.3.1.	Each password shall be a minimum of six characters.	GO	GOP	TO	TOP	
CIP-007-1	R5.3.2.	Each password shall consist of a combination of alpha, numeric, and “special” characters.	GO	GOP	TO	TOP	
CIP-007-1	R5.3.3.	Each password shall be changed at least annually, or more frequently based on risk.	GO	GOP	TO	TOP	
CIP-007-1	R6.	Security Status Monitoring — The Responsible Entity shall ensure that all Cyber Assets within the Electronic Security Perimeter, as technically feasible, implement automated tools or organizational process controls to monitor system events that are related to cyber security.	GO	GOP	TO	TOP	
CIP-007-1	R6.1.	The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for monitoring for security events on all Cyber Assets within the Electronic Security Perimeter.	GO	GOP	TO	TOP	
CIP-007-1	R6.2.	The security monitoring controls shall issue automated or manual alerts for detected Cyber Security Incidents.	GO	GOP	TO	TOP	
CIP-007-1	R6.3.	The Responsible Entity shall maintain logs of system events related to cyber security, where technically feasible, to support incident response as required in Standard CIP-008.	GO	GOP	TO	TOP	
CIP-007-1	R6.4.	The Responsible Entity shall retain all logs specified in Requirement R6 for ninety calendar days.	GO	GOP	TO	TOP	
CIP-007-1	R6.5.	The Responsible Entity shall review logs of system events related to cyber security and maintain records documenting review of logs.	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-007-1	R7.	Disposal or Redeployment — The Responsible Entity shall establish formal methods, processes, and procedures for disposal or redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005.	GO	GOP	TO	TOP	
CIP-007-1	R7.1.	Prior to the disposal of such assets, the Responsible Entity shall destroy or erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.	GO	GOP	TO	TOP	
CIP-007-1	R7.2.	Prior to redeployment of such assets, the Responsible Entity shall, at a minimum, erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.	GO	GOP	TO	TOP	
CIP-007-1	R7.3.	The Responsible Entity shall maintain records that such assets were disposed of or redeployed in accordance with documented procedures.	GO	GOP	TO	TOP	
CIP-007-1	R8.	Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of all Cyber Assets within the Electronic Security Perimeter at least annually. The vulnerability assessment shall include, at a minimum, the following:	GO	GOP	TO	TOP	
CIP-007-1	R8.1.	A document identifying the vulnerability assessment process;	GO	GOP	TO	TOP	
CIP-007-1	R8.2.	A review to verify that only ports and services required for operation of the Cyber Assets within the Electronic Security Perimeter are enabled;	GO	GOP	TO	TOP	
CIP-007-1	R8.3.	A review of controls for default accounts; and,	GO	GOP	TO	TOP	
CIP-007-1	R8.4.	Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.	GO	GOP	TO	TOP	
CIP-007-1	R9.	Documentation Review and Maintenance — The Responsible Entity shall review and update the documentation specified in Standard CIP-007 at least annually. Changes resulting from modifications to the systems or controls shall be documented	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		within ninety calendar days of the change.					
CIP-008-1	R1.	Cyber Security Incident Response Plan — The Responsible Entity shall develop and maintain a Cyber Security Incident response plan. The Cyber Security Incident Response plan shall address, at a minimum, the following:	GO	GOP	TO	TOP	
CIP-008-1	R1.1.	Procedures to characterize and classify events as reportable Cyber Security Incidents.	GO	GOP	TO	TOP	
CIP-008-1	R1.2.	Response actions, including roles and responsibilities of incident response teams, incident handling procedures, and communication plans.	GO	GOP	TO	TOP	
CIP-008-1	R1.3.	Process for reporting Cyber Security Incidents to the Electricity Sector Information Sharing and Analysis Center (ES ISAC). The Responsible Entity must ensure that all reportable Cyber Security Incidents are reported to the ES ISAC either directly or through an intermediary.	GO	GOP	TO	TOP	
CIP-008-1	R1.4.	Process for updating the Cyber Security Incident response plan within ninety calendar days of any changes.	GO	GOP	TO	TOP	
CIP-008-1	R1.5.	Process for ensuring that the Cyber Security Incident response plan is reviewed at least annually.	GO	GOP	TO	TOP	
CIP-008-1	R1.6.	Process for ensuring the Cyber Security Incident response plan is tested at least annually. A test of the incident response plan can range from a paper drill, to a full operational exercise, to the response to an actual incident.	GO	GOP	TO	TOP	
CIP-008-1	R2.	Cyber Security Incident Documentation — The Responsible Entity shall keep relevant documentation related to Cyber Security Incidents reportable per Requirement R1.1 for three calendar years.	GO	GOP	TO	TOP	
CIP-009-1	R1.	Recovery Plans — The Responsible Entity shall create and annually review recovery plan(s) for Critical Cyber Assets. The recovery plan(s) shall address at a minimum the following:	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-009-1	R1.1.	Specify the required actions in response to events or conditions of varying duration and severity that would activate the recovery plan(s).	GO	GOP	TO	TOP	
CIP-009-1	R1.2.	Define the roles and responsibilities of responders.	GO	GOP	TO	TOP	
CIP-009-1	R2.	Exercises — The recovery plan(s) shall be exercised at least annually. An exercise of the recovery plan(s) can range from a paper drill, to a full operational exercise, to recovery from an actual incident.	GO	GOP	TO	TOP	
CIP-009-1	R3.	Change Control — Recovery plan(s) shall be updated to reflect any changes or lessons learned as a result of an exercise or the recovery from an actual incident. Updates shall be communicated to personnel responsible for the activation and implementation of the recovery plan(s) within ninety calendar days of the change.	GO	GOP	TO	TOP	
CIP-009-1	R4.	Backup and Restore — The recovery plan(s) shall include processes and procedures for the backup and storage of information required to successfully restore Critical Cyber Assets. For example, backups may include spare electronic components or equipment, written documentation of configuration settings, tape backup, etc.	GO	GOP	TO	TOP	
CIP-009-1	R5.	Testing Backup Media — Information essential to recovery that is stored on backup media shall be tested at least annually to ensure that the information is available. Testing can be completed off site.	GO	GOP	TO	TOP	
COM-001-1	R1.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide adequate and reliable telecommunications facilities for the exchange of Interconnection and operating information:				TOP	
COM-001-1.1	R1.1.	Internally.				TOP	
COM-001-1.1	R1.2.	Between the Reliability Coordinator and its Transmission Operators and Balancing Authorities.				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
COM-001-1.1	R1.3.	With other Reliability Coordinators, Transmission Operators, and Balancing Authorities as necessary to maintain reliability.				TOP	
COM-001-1.1	R1.4.	Where applicable, these facilities shall be redundant and diversely routed.				TOP	
COM-001-1.1	R2.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall manage, alarm, test and/or actively monitor vital telecommunications facilities. Special attention shall be given to emergency telecommunications facilities and equipment not used for routine communications.				TOP	
COM-001-1.1	R3.	Each Reliability Coordinator, Transmission Operator and Balancing Authority shall provide a means to coordinate telecommunications among their respective areas. This coordination shall include the ability to investigate and recommend solutions to telecommunications problems within the area and with other areas.				TOP	
COM-001-1.1	R4.	Unless agreed to otherwise, each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use English as the language for all communications between and among operating personnel responsible for the real-time generation control and operation of the interconnected Bulk Electric System. Transmission Operators and Balancing Authorities may use an alternate language for internal operations.				TOP	
COM-001-1.1	R5.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have written operating instructions and procedures to enable continued operation of the system during the loss of telecommunications facilities.				TOP	
COM-002-2	R1.	Each Transmission Operator, Balancing Authority, and Generator Operator shall have communications (voice and data links) with appropriate Reliability Coordinators, Balancing Authorities, and Transmission Operators. Such communications shall be staffed and available for addressing a real-time emergency condition.		GOP		TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
COM-002-2	R1.1.	Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator, and all other potentially affected Balancing Authorities and Transmission Operators through predetermined communication paths of any condition that could threaten the reliability of its area or when firm load shedding is anticipated.				TOP	
COM-002-2	R2.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall issue directives in a clear, concise, and definitive manner; shall ensure the recipient of the directive repeats the information back correctly; and shall acknowledge the response as correct or repeat the original statement to resolve any misunderstandings.				TOP	
EOP-001-0	R2.	The Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission Operator will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes.				TOP	
EOP-001-0	R3.	Each Transmission Operator and Balancing Authority shall:				TOP	
EOP-001-0	R3.1.	Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.				TOP	
EOP-001-0	R3.2.	Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.				TOP	
EOP-001-0	R3.3.	Develop, maintain, and implement a set of plans for load shedding.				TOP	
EOP-001-0	R3.4.	Develop, maintain, and implement a set of plans for system restoration.				TOP	
EOP-001-0	R4.	Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		Balancing Authority emergency plans shall include:					
EOP-001-0	R4.1.	Communications protocols to be used during emergencies.				TOP	
EOP-001-0	R4.2.	A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions.				TOP	
EOP-001-0	R4.3.	The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.				TOP	
EOP-001-0	R4.4.	Staffing levels for the emergency.				TOP	
EOP-001-0	R5.	Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001-0 when developing an emergency plan.				TOP	
EOP-001-0	R6.	The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.				TOP	
EOP-001-0	R7.	The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable:				TOP	
EOP-001-0	R7.1.	The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.				TOP	
EOP-001-0	R7.2.	The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.				TOP	



Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
EOP-001-0	R7.3.	The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules, <a href="#">including outages to the Generator Interconnection Facility</a> , to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)				TOP	
EOP-001-0	R7.4.	The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.				TOP	
EOP-003-1	R1.	After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.				TOP	
EOP-003-1	R2.	Each Transmission Operator and Balancing Authority shall establish plans for automatic load shedding for underfrequency or undervoltage conditions.				TOP	
EOP-003-1	R3.	Each Transmission Operator and Balancing Authority shall coordinate load shedding plans among other interconnected Transmission Operators and Balancing Authorities.				TOP	
EOP-003-1	R4.	A Transmission Operator or Balancing Authority shall consider one or more of these factors in designing an automatic load shedding scheme: frequency, rate of frequency decay, voltage level, rate of voltage decay, or power flow levels.				TOP	
EOP-003-1	R5.	A Transmission Operator or Balancing Authority shall implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.				TOP	
EOP-003-1	R6.	After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
EOP-003-1	R7.	The Transmission Operator, <a href="#">Generator Operator</a> , and Balancing Authority shall coordinate automatic load shedding throughout their areas with underfrequency isolation of generating units, tripping of shunt capacitors, and other automatic actions that will occur under abnormal frequency, voltage, or power flow conditions.				TOP	<a href="#">Generic issue: -Need to add Generator Operator applicability to ensure the units' frequency trip set points are appropriately included in the needed coordination. This change is required only if the PRC-024-1 standard under development now as part of the Generator Verification drafting team does not adequately address the issue.</a>
EOP-003-1	R8.	Each Transmission Operator or Balancing Authority shall have plans for operator-controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.				TOP	
EOP-004-1	R2.	A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load-Serving Entity shall promptly analyze Bulk Electric System disturbances on its system or facilities, <a href="#">including those for the Generator Interconnection Facility</a> .		GOP		TOP	
EOP-004-1	R3.	A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load-Serving Entity experiencing a reportable incident shall provide a preliminary written report to its Regional Reliability Organization and NERC.		GOP		TOP	
EOP-004-1	R3.1.	The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load-Serving Entity shall submit within 24 hours of the disturbance or unusual occurrence either a copy of the report submitted to DOE, or, if no DOE report is required, a copy of the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report form. Events that are not identified until some time after they occur shall be reported within 24 hours of being recognized.		GOP		TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
EOP-004-1	R3.2.	Applicable reporting forms are provided in Attachments 022-1 and 022-2.		GOP		TOP	
EOP-004-1	R3.3.	Under certain adverse conditions, e.g., severe weather, it may not be possible to assess the damage caused by a disturbance and issue a written Interconnection Reliability Operating Limit and Preliminary Disturbance Report within 24 hours. In such cases, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load-Serving Entity shall promptly notify its Regional Reliability Organization(s) and NERC, and verbally provide as much information as is available at that time. The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load-Serving Entity shall then provide timely, periodic verbal updates until adequate information is available to issue a written Preliminary Disturbance Report.		GOP		TOP	
EOP-004-1	R3.4.	If, in the judgment of the Regional Reliability Organization, after consultation with the Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load-Serving Entity in which a disturbance occurred, a final report is required, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load-Serving Entity shall prepare this report within 60 days. As a minimum, the final report shall have a discussion of the events and its cause, the conclusions reached, and recommendations to prevent recurrence of this type of event. The report shall be subject to Regional Reliability Organization approval.		GOP		TOP	
EOP-005-1	R1.	Each Transmission Operator shall have a restoration plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shutdown of its system, including necessary operating instructions and procedures to cover emergency conditions, and the loss of vital telecommunications channels. Each Transmission Operator shall include the applicable elements listed in Attachment 1-EOP-005 in developing a restoration plan.				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
EOP-005-1	R2.	Each Transmission Operator shall review and update its restoration plan at least annually and whenever it makes changes in the power system network, and shall correct deficiencies found during the simulated restoration exercises.				TOP	
EOP-005-1	R3.	Each Transmission Operator shall develop restoration plans with a priority of restoring the integrity of the Interconnection.				TOP	
EOP-005-1	R4.	Each Transmission Operator shall coordinate its restoration plans with the Generator Owners and Balancing Authorities within its area, its Reliability Coordinator, and neighboring Transmission Operators and Balancing Authorities.				TOP	
EOP-005-1	R5.	Each Transmission Operator and Balancing Authority shall periodically test its telecommunication facilities needed to implement the restoration plan.				TOP	
EOP-005-1	R6.	Each Transmission Operator and Balancing Authority shall train its operating personnel in the implementation of the restoration plan. Such training shall include simulated exercises, if practicable.				TOP	
EOP-005-1	R7.	Each Transmission Operator and Balancing Authority shall verify the restoration procedure by actual testing or by simulation.				TOP	
EOP-005-1	R8.	Each Transmission Operator shall verify that the number, size, availability, and location of system blackstart generating units are sufficient to meet Regional Reliability Organization restoration plan requirements for the Transmission Operator's area.				TOP	
EOP-005-1	R9.	The Transmission Operator shall document the Cranking Paths, including initial switching requirements, between each blackstart generating unit and the unit(s) to be started and shall provide this documentation for review by the Regional Reliability Organization upon request. Such documentation may include Cranking Path diagrams.				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
EOP-005-1	R10.	The Transmission Operator shall demonstrate, through simulation or testing, that the blackstart generating units in its restoration plan can perform their intended functions as required in the regional restoration plan.				TOP	
EOP-005-1	R10.1.	The Transmission Operator shall perform this simulation or testing at least once every five years.				TOP	
EOP-005-1	R11.	Following a disturbance in which one or more areas of the Bulk Electric System become isolated or blacked out, the affected Transmission Operators and Balancing Authorities shall begin immediately to return the Bulk Electric System to normal.				TOP	
EOP-005-1	R11.1.	The affected Transmission Operators and Balancing Authorities shall work in conjunction with their Reliability Coordinator(s) to determine the extent and condition of the isolated area(s).				TOP	
EOP-005-1	R11.2.	The affected Transmission Operators and Balancing Authorities shall take the necessary actions to restore Bulk Electric System frequency to normal, including adjusting generation, placing additional generators on line, or load shedding.				TOP	
EOP-005-1	R11.4.	The affected Transmission Operators shall give high priority to restoration of off-site power to nuclear stations.				TOP	
EOP-005-1	R11.5.	The affected Transmission Operators may resynchronize the isolated area(s) with the surrounding area(s) when the following conditions are met:				TOP	The team identified this as a potential general issue. However, when one considers the new requirements recommended (found in TOP-001 R7 Comment area), the TOP has decision-making authority over the <a href="#">Generator Interconnection Operational Interface</a> , there is no gap created through this specific requirement.
EOP-005-1	R11.5.1.	Voltage, frequency, and phase angle permit.				TOP	
EOP-005-1	R11.5.2.	The size of the area being reconnected and the capacity of the transmission lines effecting the reconnection and the number of				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		synchronizing points across the system are considered.					
EOP-005-1	R11.5.3.	Reliability Coordinator(s) and adjacent areas are notified and Reliability Coordinator approval is given.				TOP	
EOP-005-1	R11.5.4.	Load is shed in neighboring areas, if required, to permit successful interconnected system restoration.				TOP	
EOP-008-0	R1.	Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have a plan to continue reliability operations in the event its control center becomes inoperable. The contingency plan must meet the following requirements:				TOP	
EOP-008-0	R1.1.	The contingency plan shall not rely on data or voice communication from the primary control facility to be viable.				TOP	
EOP-008-0	R1.2.	The plan shall include procedures and responsibilities for providing basic tie line control and procedures and for maintaining the status of all inter-area schedules, such that there is an hourly accounting of all schedules.				TOP	
EOP-008-0	R1.3.	The contingency plan must address monitoring and control of critical transmission facilities, <a href="#">Generator Interconnection Operational Interface</a> , generation control, voltage control, time and frequency control, control of critical substation devices, and logging of significant power system events. The plan shall list the critical facilities.				TOP	
EOP-008-0	R1.4.	The plan shall include procedures and responsibilities for maintaining basic voice communication capabilities with other areas.				TOP	
EOP-008-0	R1.5.	The plan shall include procedures and responsibilities for conducting periodic tests, at least annually, to ensure viability of the plan.				TOP	
EOP-008-0	R1.6.	The plan shall include procedures and responsibilities for providing annual training to ensure that operating personnel are able to implement the contingency plans.				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
EOP-008-0	R1.7.	The plan shall be reviewed and updated annually.				TOP	
EOP-008-0	R1.8.	Interim provisions must be included if it is expected to take more than one hour to implement the contingency plan for loss of primary control facility.				TOP	
EOP-009-0	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.		GOP			
EOP-009-0	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.	GO	GOP			
FAC-001-0	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:			TO		
FAC-001-0	R1.1.	Generation facilities, <a href="#">including the Generator Interconnection Facility</a> ,			TO		
FAC-001-0	R1.2.	Transmission facilities, and			TO		
FAC-001-0	R1.3.	End-user facilities			TO		
FAC-001-0	R2.	The Transmission Owner's facility connection requirements shall address, but are not limited to, the following items:			TO		
FAC-001-0	R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:			TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
FAC-001-0	R2.1.1.	Procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems.			TO		
FAC-001-0	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.			TO		
FAC-001-0	R2.1.3.	Voltage level and MW and MVAR capacity or demand at point of connection.			TO		
FAC-001-0	R2.1.4.	Breaker duty and surge protection.			TO		
FAC-001-0	R2.1.5.	System protection and coordination.			TO		
FAC-001-0	R2.1.6.	Metering and telecommunications.			TO		
FAC-001-0	R2.1.7.	Grounding and safety issues.			TO		
FAC-001-0	R2.1.8.	Insulation and insulation coordination.			TO		
FAC-001-0	R2.1.9.	Voltage, Reactive Power, and power factor control.			TO		
FAC-001-0	R2.1.10.	Power quality impacts.			TO		
FAC-001-0	R2.1.11.	Equipment Ratings.			TO		
FAC-001-0	R2.1.12.	Synchronizing of facilities.			TO		
FAC-001-0	R2.1.13.	Maintenance coordination.			TO		
FAC-001-0	R2.1.14.	Operational issues (abnormal frequency and voltages).			TO		
FAC-001-0	R2.1.15.	Inspection requirements for existing or new facilities.			TO		
FAC-001-0	R2.1.16.	Communications and procedures during normal and emergency operating conditions.			TO		
FAC-001-0	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, the Regional Reliability Organization, and NERC on request (five business days).			TO		



Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
FAC-002-0	R1.	The Generator Owner, Transmission Owner, Distribution Provider, and Load-Serving Entity seeking to integrate generation facilities, transmission facilities, and electricity end-user facilities shall each coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority. The assessment shall include:	GO		TO		
FAC-002-0	R1.1.	Evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems.	GO		TO		
FAC-002-0	R1.2.	Ensurance of compliance with NERC Reliability Standards and applicable Regional, subregional, Power Pool, and individual system planning criteria and facility connection requirements.	GO		TO		
FAC-002-0	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.	GO		TO		
FAC-002-0	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.	GO		TO		
FAC-002-0	R1.5.	Documentation that the assessment included study assumptions, system performance, alternatives considered, and jointly coordinated recommendations.	GO		TO		
FAC-002-0	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 Organization(s) Regional Reliability Organization(s) and NERC on request (within 30 calendar days).	GO		TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
FAC-003-1	R1.	The Transmission owner <u>and Generator Owner</u> shall prepare, and keep current, a formal transmission vegetation management (TVMP). The TVMP shall include the Transmission Owner's <u>and Generator Owner's</u> objectives, practices, approved procedures, and work Specifications. 1. ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.			TO		<a href="#">Applies to the Generator Interconnection Facility above 200 kV that exceeds two spans from the generator property line or are otherwise deemed critical by the Regional Entity below 200 kV (subject to the two-span criteria.)</a>
FAC-003-1	R1.1.	The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the Transmission Owner's <u>or Generator Owner's</u> transmission lines.			TO		
FAC-003-1	R1.2.	The Transmission Owner <u>and Generator Owner</u> , in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the Transmission Owner <u>and Generator Owner</u> shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.			TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
FAC-003-1	R1.2.1.	Clearance 1 — The Transmission Owner <a href="#">and Generator Owner</a> shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the Transmission Owner <a href="#">or Generator Owner</a> plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.			TO		
FAC-003-1	R1.2.2.	Clearance 2 — The Transmission Owner <a href="#">and Generator Owner</a> shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These Transmission Owner-specific <a href="#">and Generator Owner-specific</a> minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 ( <i>Guide for Maintenance Methods on Energized Power Lines</i> ) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.			TO		
FAC-003-1	R1.2.2.1.	Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.			TO		
FAC-003-1	R1.2.2.2.	Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude			TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		correction factors applied.					
FAC-003-1	R1.3.	All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner <u>or Generator Owner</u> , to perform their duties.			TO		
FAC-003-1	R1.4.	Each Transmission Owner <u>and Generator Owner</u> shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner <u>or Generator Owner</u> is restricted from attaining the clearances specified in Requirement 1.2.1.			TO		
FAC-003-1	R1.5.	Each Transmission Owner <u>and Generator Owner</u> shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.			TO		
FAC-003-1	R2.	The Transmission Owner <u>and Generator Owner</u> shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each Transmission Owner <u>and Generator Owner</u> shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.			TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
FAC-003-1	R3.	The Transmission Owner <a href="#">and Generator Owner</a> shall report quarterly to its RRO, or the RRO's designee, sustained transmission line outages determined by the Transmission Owner <a href="#">or Generator Owner</a> to have been caused by vegetation.			TO		
FAC-003-1	R3.1.	Multiple sustained 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.			TO		
FAC-003-1	R3.2.	The Transmission Owner <a href="#">or Generator Owner</a> is not required to report to the RRO, or the RRO's designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the Transmission Owner, <a href="#">Generator Owner</a> , or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).			TO		
FAC-003-1	R3.3.	The outage information provided by the Transmission Owner <a href="#">or Generator Owner</a> to the RRO, or the RRO's designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the Transmission Owner <a href="#">or Generator Owner</a> .			TO		
FAC-003-1	R3.4.	An outage shall be categorized as one of the following:			TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
FAC-003-1	R3.4.1.	Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;			TO		
FAC-003-1	R3.4.2.	Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;			TO		
FAC-003-1	R3.4.3.	Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.			TO		
FAC-008-1	R1.	The Transmission Owner and Generator Owner shall each document its current methodology used for developing Facility Ratings (Facility Ratings Methodology) of its solely and jointly owned Facilities, <a href="#">including the Generator Interconnection Facility</a> . The methodology shall include all of the following:	GO		TO		
FAC-008-1	R1.1.	A statement that a Facility Rating shall equal the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.	GO		TO		
FAC-008-1	R1.2.	The method by which the Rating (of major BES equipment that comprises a Facility) is determined.	GO		TO		
FAC-008-1	R1.2.1.	The scope of equipment addressed shall include, but not be limited to, generators, <a href="#">the Generator Interconnection Facility</a> , transmission conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.	GO		TO		
FAC-008-1	R1.2.2.	The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.	GO		TO		
FAC-008-1	R1.3.	Consideration of the following:	GO		TO		
FAC-008-1	R1.3.1.	Ratings provided by equipment manufacturers.	GO		TO		
FAC-008-1	R1.3.2.	Design criteria (e.g., including applicable references to industry Rating practices such as manufacturer's warranty, IEEE, ANSI or other standards).	GO		TO		
FAC-008-1	R1.3.3.	Ambient conditions.	GO		TO		
FAC-008-1	R1.3.4.	Operating limitations.	GO		TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
FAC-008-1	R1.3.5.	Other assumptions.	GO		TO		
FAC-008-1	R2.	The Transmission Owner and Generator Owner shall each make its Facility Ratings Methodology available for inspection and technical review by those Reliability Coordinators, Transmission Operators, Transmission Planners, and Planning Authorities that have responsibility for the area in which the associated Facilities are located, within 15 business days of receipt of a request.	GO		TO		
FAC-008-1	R3.	If a Reliability Coordinator, Transmission Operator, Transmission Planner, or Planning Authority provides written comments on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings Methodology, the Transmission Owner or Generator Owner shall provide a written response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Facility Ratings Methodology and, if no change will be made to that Facility Ratings Methodology, the reason why.	GO		TO		
FAC-009-1 	R1.	The Transmission Owner and Generator Owner shall each establish Facility Ratings for its solely and jointly owned Facilities, <a href="#">including the Generator Interconnection Facility</a> , that are consistent with the associated Facility Ratings Methodology.	GO		TO		
FAC-009-1 	R2.	The Transmission Owner and Generator Owner shall each provide Facility Ratings for its solely and jointly owned Facilities, <a href="#">including the Generator Interconnection Facility</a> , -that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities to its associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) as scheduled by such requesting entities.	GO		TO		
FAC-014-1	R2.	The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		Coordinator's SOL Methodology.					
FAC-014-1	R5.2.	The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.				TOP	
INT-004-2	R2.3.	A Reliability Coordinator or Transmission Operator determines the deviation, regardless of magnitude, to be a reliability concern and notifies the Purchasing-Selling Entity of that determination and the reasons.				TOP	
IRO-001-1.1	R8.	Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall comply with Reliability Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability Coordinator may implement alternate remedial actions.		GOP		TOP	
IRO-002-1	R3.	Each Reliability Coordinator – or its Transmission Operators and Balancing Authorities – shall provide, or arrange provisions for, data exchange to other Reliability Coordinators or Transmission Operators and Balancing Authorities via a secure network.				TOP	
IRO-004-1	R3.	Each Reliability Coordinator shall, in conjunction with its Transmission Operators and Balancing Authorities, develop action plans that may be required, including reconfiguration of the transmission system, re-dispatching of generation, reduction or curtailment of Interchange Transactions, or reducing load to return transmission loading to within acceptable SOLs or IROLs.				TOP	



Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
IRO-004-1	R4.	Each Transmission Operator, Balancing Authority, Transmission Owner, Generator Owner, Generator Operator, and Load-Serving Entity in the Reliability Coordinator Area shall provide information required for system studies, such as critical facility status, Load, generation, operating reserve projections, and known Interchange Transactions. This information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.	GO	GOP	TO	TOP	
IRO-004-1	R7.	Each Transmission Operator, Balancing Authority, and Transmission Service Provider shall comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events.				TOP	The team considered whether an existing GOP-specific requirement existed to close what could have been a gap in coverage. The team concluded that IRO-001-1 R8 addresses this issue. Therefore, no gap exists.
IRO-005-2	R3.	As portions of the transmission system approach or exceed SOLs or IROLs, the Reliability Coordinator shall work with its Transmission Operators and Balancing Authorities to evaluate and assess any additional Interchange Schedules that would violate those limits. If a potential or actual IROL violation cannot be avoided through proactive intervention, the Reliability Coordinator shall initiate control actions or emergency procedures to relieve the violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall ensure all resources, including load shedding, are available to address a potential or actual IROL violation.				TOP	
IRO-005-2	R6.	Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
IRO-005-2	R8.	Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.				TOP	
IRO-005-2	R9.	The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages, <a href="#">including the Generator Interconnection Facility</a> , with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.		GOP		TOP	
IRO-005-2	R12.	Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.				TOP	General issue with generators: For generating units that participate in some fashion in a Special Protection System or Remedial Action System that has supporting relaying or control equipment to enable this functionality, the GOP must notify the TOP of a status or condition change of the equipment. Therefore, a new requirement specific to the GOP must be added:  <a href="#">Rx. The Generator Operator shall immediately inform the Transmission Operator of the status of the Special Protection System, including any degradation or potential failure to operate as expected for SPS relay or control equipment under its control.</a>

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
IRO-005-2	R13.	Each Reliability Coordinator shall ensure that all Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities operate to prevent the likelihood that a disturbance, action, or non-action in its Reliability Coordinator Area will result in a SOL or IROL violation in another area of the Interconnection. In instances where there is a difference in derived limits, the Reliability Coordinator and its Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.		GOP		TOP	
IRO-005-2	R15.	Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.				TOP	
IRO-005-2	R17.	When an IROL or SOL is exceeded, the Reliability Coordinator shall evaluate the local and wide-area impacts, both real-time and post-contingency, and determine if the actions being taken are appropriate and sufficient to return the system to within IROL in thirty minutes. If the actions being taken are not appropriate or sufficient, the Reliability Coordinator shall direct the Transmission Operator, Balancing Authority, Generator Operator, or Load-Serving Entity to return the system to within IROL or SOL.		GOP		TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
MOD-010-0 	R1.	The Transmission Owners, Transmission Planners, Generator Owners <u>(for plant and the Generator Interconnection Facility)</u> , and Resource Planners <del>-(specified in the data requirements and reporting procedures of MOD-011-0_R1)</del> shall provide appropriate equipment characteristics, system data, and existing and future Interchange Schedules in compliance with its respective Interconnection Regional steady-state modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-011-0_R 1.	GO		TO		
MOD-010-0 	R2.	The Transmission Owners, Transmission Planners, Generator Owners <u>(for plant and the Generator Interconnection Facility)</u> , and Resource Planners <del>-(specified in the data requirements and reporting procedures of MOD-011-0_R1)</del> shall provide this steady-state modeling and simulation data to the Regional Reliability Organizations, NERC, and those entities specified within Reliability Standard MOD-011-0_R 1. If no schedule exists, then these entities shall provide the data on request (30 calendar days).	GO		TO		
MOD-012-0 	R1.	The Transmission Owners, Transmission Planners, Generator Owners <u>(for plant and the Generator Interconnection Facility)</u> , and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R1) shall provide appropriate equipment characteristics and system data in compliance with the respective Interconnection-wide Regional dynamics system modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-013-0_R1.	GO		TO		
MOD-012-0 	R2.	The Transmission Owners, Transmission Planners, Generator Owners <u>(for plant and the Generator Interconnection Facility)</u> , and Resource Planners (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 entities specified within the applicable reporting procedures identified in Reliability Standard MOD-013-0_R 1. If no schedule exists,	GO		TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		then these entities shall provide data on request (30 calendar days).					
NUC-001-1	R1.	The Nuclear Plant Generator Operator shall provide the proposed NPIRs in writing to the applicable Transmission Entities and shall verify receipt	GO	GOP	TO	TOP	
NUC-001-1	R2.	The Nuclear Plant Generator Operator and the applicable Transmission Entities shall have in effect one or more Agreements <sup>1</sup> that include mutually agreed to NPIRs and document how the Nuclear Plant Generator Operator and the applicable Transmission Entities shall address and implement these NPIRs.	GO	GOP	TO	TOP	
NUC-001-1	R3.	Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall incorporate the NPIRs into their planning analyses of the electric system and shall communicate the results of these analyses to the Nuclear Plant Generator Operator.	GO	GOP	TO	TOP	
NUC-001-1	R4.	Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall:	GO	GOP	TO	TOP	
NUC-001-1	R4.1.	Incorporate the NPIRs into their operating analyses of the electric system.	GO	GOP	TO	TOP	
NUC-001-1	R4.2.	Operate the electric system to meet the NPIRs.	GO	GOP	TO	TOP	
NUC-001-1	R4.3.	Inform the Nuclear Plant Generator Operator when the ability to assess the operation of the electric system affecting NPIRs is lost.	GO	GOP	TO	TOP	
NUC-001-1	R5.	The Nuclear Plant Generator Operator shall operate per the Agreements developed in accordance with this standard.		GOP			
NUC-001-1	R6.	Per the Agreements developed in accordance with this standard, the applicable Transmission Entities and the Nuclear Plant Generator Operator shall coordinate outages and maintenance activities which affect the NPIRs.	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
NUC-001-1	R7.	Per the Agreements developed in accordance with this standard, the Nuclear Plant Generator Operator shall inform the applicable Transmission Entities of actual or proposed changes to nuclear plant design, configuration, operations, limits, protection systems, or capabilities that may impact the ability of the electric system to meet the NPIRs.	GO	GOP	TO	TOP	
NUC-001-1	R8.	Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall inform the Nuclear Plant Generator Operator of actual or proposed changes to electric system design, configuration, operations, limits, protection systems, or capabilities that may impact the ability of the electric system to meet the NPIRs.	GO	GOP	TO	TOP	
NUC-001-1	R9.	The Nuclear Plant Generator Operator and the applicable Transmission Entities shall include, as a minimum, the following elements within the agreement(s) identified in R2:	GO	GOP	TO	TOP	
NUC-001-1	R9.1.	Administrative elements:	GO	GOP	TO	TOP	
NUC-001-1	R9.1.1.	Definitions of key terms used in the agreement.	GO	GOP	TO	TOP	
NUC-001-1	R9.1.2.	Names of the responsible entities, organizational relationships, and responsibilities related to the NPIRs.	GO	GOP	TO	TOP	
NUC-001-1	R9.1.3.	A requirement to review the agreement(s) at least every three years.	GO	GOP	TO	TOP	
NUC-001-1	R9.1.4.	A dispute resolution mechanism.	GO	GOP	TO	TOP	
NUC-001-1	R9.2.	Technical requirements and analysis:	GO	GOP	TO	TOP	
NUC-001-1	R9.2.1.	Identification of parameters, limits, configurations, and operating scenarios included in the NPIRs and, as applicable, procedures for providing any specific data not provided within the agreement.	GO	GOP	TO	TOP	
NUC-001-1	R9.2.2.	Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs.	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
NUC-001-1	R9.2.3.	Types of planning and operational analyses performed specifically to support the NPIRs, including the frequency of studies and types of Contingencies and scenarios required.	GO	GOP	TO	TOP	
NUC-001-1	R9.3.	Operations and maintenance coordination:	GO	GOP	TO	TOP	
NUC-001-1	R9.3.1.	Designation of ownership of electrical facilities at the interface between the electric system and the nuclear plant and responsibilities for operational control coordination and maintenance of these facilities.	GO	GOP	TO	TOP	
NUC-001-1	R9.3.2.	Identification of any maintenance requirements for equipment not owned or controlled by the Nuclear Plant Generator Operator that are necessary to meet the NPIRs.	GO	GOP	TO	TOP	
NUC-001-1	R9.3.3.	Coordination of testing, calibration and maintenance of on-site and off-site power supply systems and related components.	GO	GOP	TO	TOP	
NUC-001-1	R9.3.4.	Provisions to address mitigating actions needed to avoid violating NPIRs and to address periods when responsible Transmission Entity loses the ability to assess the capability of the electric system to meet the NPIRs. These provisions shall include responsibility to notify the Nuclear Plant Generator Operator within a specified time frame.	GO	GOP	TO	TOP	
NUC-001-1	R9.3.5.	Provision to consider nuclear plant coping times required by the NPIRs and their relation to the coordination of grid and nuclear plant restoration following a nuclear plant loss of Off-site Power.	GO	GOP	TO	TOP	
NUC-001-1	R9.3.6.	Coordination of physical and cyber security protection of the Bulk Electric System at the nuclear plant interface to ensure each asset is covered under at least one entity's plan.	GO	GOP	TO	TOP	
NUC-001-1	R9.3.7.	Coordination of the NPIRs with transmission system Special Protection Systems and underfrequency and undervoltage load shedding programs.	GO	GOP	TO	TOP	
NUC-001-1	R9.4.	Communications and training:	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
NUC-001-1	R9.4.1.	Provisions for communications between the Nuclear Plant Generator Operator and Transmission Entities, including communications protocols, notification time requirements, and definitions of terms.	GO	GOP	TO	TOP	
NUC-001-1	R9.4.2.	Provisions for coordination during an off-normal or emergency event affecting the NPIRs, including the need to provide timely information explaining the event, an estimate of when the system will be returned to a normal state, and the actual time the system is returned to normal.	GO	GOP	TO	TOP	
NUC-001-1	R9.4.3.	Provisions for coordinating investigations of causes of unplanned events affecting the NPIRs and developing solutions to minimize future risk of such events.	GO	GOP	TO	TOP	
NUC-001-1	R9.4.4.	Provisions for supplying information necessary to report to government agencies, as related to NPIRs.	GO	GOP	TO	TOP	
NUC-001-1	R9.4.5.	Provisions for personnel training, as related to NPIRs.	GO	GOP	TO	TOP	
PER-001-0	R1.	Each Transmission Operator <u>and</u> Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.				TOP	<a href="#">Add R2 to PER-001-0 as follows: R2. Each Generator Operator shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Generation Facility and Generation Interconnection Facility, and the responsibility and authority to follow the directives of reliability authorities including the Transmission Operator and Balancing Authority.</a>
PER-002-0	R1.	Each Transmission Operator, <u>Generator Operator</u> , and Balancing Authority shall be staffed with adequately trained operating personnel.				TOP	
PER-002-0	R2.	Each Transmission Operator and Balancing Authority shall have a training program for all operating personnel that are in:				TOP	To ensure complete coverage for the training of personnel with



Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
							responsibility for operating the Generator Interconnection Facilities, a new requirement is needed: <a href="#">Add R3 as follows:</a> <a href="#">R3. Each Generator Operator shall implement an initial and continuing training program for all operating personnel that are responsible for operating the Generator Interconnection Facility that verifies the personnel's ability and understanding to operate the equipment in a reliable manner.</a>
PER-002-0	R2.1.	Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System.				TOP	
PER-002-0	R2.2.	Positions directly responsible for complying with NERC standards.				TOP	
PER-002-0	R3.	For personnel identified in Requirement R2, the Transmission Operator and Balancing Authority shall provide a training program meeting the following criteria:				TOP	
PER-002-0	R3.1.	A set of training program objectives must be defined, based on NERC and Regional Reliability Organization standards, entity operating procedures, and applicable regulatory requirements. These objectives shall reference the knowledge and competencies needed to apply those standards, procedures, and requirements to normal, emergency, and restoration conditions for the Transmission Operator and Balancing Authority operating positions.				TOP	
PER-002-0	R3.2.	The training program must include a plan for the initial and continuing training of Transmission Operator and Balancing Authority operating personnel. That plan shall address knowledge and competencies required for reliable system				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		operations.					
PER-002-0	R3.3.	The training program must include training time for all Transmission Operator and Balancing Authority operating personnel to ensure their operating proficiency.				TOP	
PER-002-0	R3.4.	Training staff must be identified, and the staff must be competent in both knowledge of system operations and instructional capabilities.				TOP	
PER-002-0	R4.	For personnel identified in Requirement R2, each Transmission Operator and Balancing Authority shall provide its operating personnel at least five days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.				TOP	
PER-003-0	R1.	Each Transmission Operator, Balancing Authority, and Reliability Coordinator shall staff all operating positions that meet both of the following criteria with personnel that are NERC-certified for the applicable functions:				TOP	
PER-003-0	R1.1.	Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System.				TOP	
PER-003-0	R1.2.	Positions directly responsible for complying with NERC standards.				TOP	
PRC-001-1	R1.	Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area, <a href="#">including those for the Generator Interconnection Facility</a> .		GOP		TOP	
PRC-001-1	R2.	Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures, <a href="#">including those for the Generator Interconnection Facility</a> , as follows:		GOP		TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
PRC-001-1	R2.1.	If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.		GOP			
PRC-001-1	R2.2.	If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.				TOP	
PRC-001-1	R3.	A Generator Operator or Transmission Operator shall coordinate new protective systems and changes, <a href="#">including those for the Generator Interconnection Facility</a> , as follows.		GOP		TOP	
PRC-001-1	R3.1.	Each Generator Operator shall coordinate all new protective systems and all protective system changes, <a href="#">including those for the Generator Interconnection Facility</a> , with its Transmission Operator and Host Balancing Authority.		GOP			
PRC-001-1	R3.2.	Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.				TOP	
PRC-001-1	R4.	Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.				TOP	
PRC-001-1	R5.	A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions, <a href="#">including those for the Generator Interconnection Facility</a> , that could require changes in the protection systems of others:		GOP		TOP	
PRC-001-1	R5.1.	Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions, <a href="#">including those for the Generator Interconnection Facility</a> , that could require changes in the Transmission Operator's protection		GOP			

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		systems.					
PRC-001-1	R5.2.	Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' protection systems.				TOP	
PRC-001-1	R6.	Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.				TOP	
PRC-004-1	R1.	The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1.			TO		
PRC-004-1	R2.	The Generator Owner shall analyze its generator Protection System Misoperations, <a href="#">including those for the Generator Interconnection Facility</a> , and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for PRC-003 R1.	GO				
PRC-004-1	R3.	The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.	GO		TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
PRC-005-1	R1.	Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System, <a href="#">including those for the Generator Interconnection Facility</a> , shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:	GO		TO		
PRC-005-1	R1.1.	Maintenance and testing intervals and their basis.	GO		TO		
PRC-005-1	R1.2.	Summary of maintenance and testing procedures.	GO		TO		
PRC-005-1	R2.	Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System, <a href="#">including those for the Generator Interconnection Facility</a> , shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include:	GO		TO		
PRC-005-1	R2.1.	Evidence Protection System devices were maintained and tested within the defined intervals.	GO		TO		
PRC-005-1	R2.2.	Date each Protection System device was last tested/maintained.	GO		TO		
PRC-007-0	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.			TO		
PRC-007-0	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 UFLS program database.			TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
PRC-007-0	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).			TO		
PRC-008-0	R1.	The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall have a UFLS equipment maintenance and testing program in place. 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.			TO		
PRC-008-0	R2.	The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall implement its UFLS equipment maintenance and testing program and shall provide UFLS maintenance and testing program results to its Regional Reliability Organization and NERC on request (within 30 calendar days).			TO		
PRC-009-0	R1.	The Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall analyze and document its UFLS program performance in accordance with its Regional Reliability Organization's UFLS program. The analysis shall address 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:			TO	TOP	
PRC-009-0	R1.1.	A description of the event including initiating conditions.			TO	TOP	
PRC-009-0	R1.2.	A review of the UFLS set points and tripping times.			TO	TOP	
PRC-009-0	R1.3.	A simulation of the event.			TO	TOP	
PRC-009-0	R1.4.	A summary of the findings.			TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
PRC-009-0	R2.	The Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide documentation of the analysis of the UFLS program to its Regional Reliability Organization and NERC on request 90 calendar days after the system event.			TO	TOP	
PRC-010-0	R1.	The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall periodically (at least every five years or as required by changes in system conditions) conduct and document an assessment of the effectiveness of the UVLS program. This assessment shall be conducted with the associated Transmission Planner(s) and Planning Authority(ies).			TO	TOP	
PRC-010-0	R1.1.	This assessment shall include, but is not limited to:			TO	TOP	
PRC-010-0	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.			TO	TOP	
PRC-010-0	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.			TO	TOP	
PRC-010-0	R1.1.3.	A review of the voltage set points and timing.			TO	TOP	
PRC-010-0	R2.	The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall provide documentation of its current UVLS program assessment to its Regional Reliability Organization and NERC on request (30 calendar days).			TO	TOP	
PRC-011-0	R1.	The Transmission Owner and Distribution Provider that owns a UVLS system shall have a UVLS equipment maintenance and testing program in place. This program shall include:			TO		
PRC-011-0	R1.1.	The UVLS system identification which shall include but is not limited to:			TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
PRC-011-0	R1.1.1.	Relays.			TO		
PRC-011-0	R1.1.2.	Instrument transformers.			TO		
PRC-011-0	R1.1.3.	Communications systems, where appropriate.			TO		
PRC-011-0	R1.1.4.	Batteries.			TO		
PRC-011-0	R1.2.	Documentation of maintenance and testing intervals and their basis.			TO		
PRC-011-0	R1.3.	Summary of testing procedure.			TO		
PRC-011-0	R1.4.	Schedule for system testing.			TO		
PRC-011-0	R1.5.	Schedule for system maintenance.			TO		
PRC-011-0	R1.6.	Date last tested/maintained.			TO		
PRC-011-0	R2.	The Transmission Owner and Distribution Provider that owns a UVLS system shall provide documentation of its UVLS equipment maintenance and testing program and the implementation of that UVLS equipment maintenance and testing program to its Regional Reliability Organization and NERC on request (within 30 calendar days).			TO		
PRC-015-0	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_R 1.	GO		TO		
PRC-015-0	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.	GO		TO		



Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
PRC-015-0	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).	GO		TO		
PRC-016-0.1	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 procedure specified in Reliability Standard PRC-012-0_R1.	GO		TO		
PRC-016-0.1	R2.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall take corrective actions to avoid future misoperations.	GO		TO		
PRC-016-0.1	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 its Regional Reliability Organization and NERC on request (within 90 calendar days).	GO		TO		
PRC-017-0	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:	GO		TO		
PRC-017-0	R1.1.	SPS identification shall include but is not limited to:	GO		TO		
PRC-017-0	R1.1.1.	Relays.	GO		TO		
PRC-017-0	R1.1.2.	Instrument transformers.	GO		TO		
PRC-017-0	R1.1.3.	Communications systems, where appropriate.	GO		TO		
PRC-017-0	R1.1.4.	Batteries.	GO		TO		
PRC-017-0	R1.2.	Documentation of maintenance and testing intervals and their basis.	GO		TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
PRC-017-0	R1.3.	Summary of testing procedure.	GO		TO		
PRC-017-0	R1.4.	Schedule for system testing.	GO		TO		
PRC-017-0	R1.5.	Schedule for system maintenance.	GO		TO		
PRC-017-0	R1.6.	Date last tested/maintained.	GO		TO		
PRC-017-0	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).	GO		TO		
PRC-018-1	R1.	Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard PRC-002 Requirements 1-3) shall have DMEs installed that meet the following requirements:	GO		TO		
PRC-018-1	R1.1.	Internal Clocks in DME devices shall be synchronized to within 2 milliseconds or less of Universal Coordinated Time scale (UTC)	GO		TO		
PRC-018-1	R1.2.	Recorded data from each Disturbance shall be retrievable for ten calendar days.	GO		TO		
PRC-018-1	R2.	The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization's installation requirements (reliability standard PRC-002 Requirements 1 through 3).	GO		TO		
PRC-018-1	R3.	The Transmission Owner and Generator Owner shall each maintain, and report to its Regional Reliability Organization on request, the following data on the DMEs installed to meet that region's installation requirements (reliability standard PRC-002 Requirements 1.1, 2.1 and 3.1):	GO		TO		
PRC-018-1	R3.1.	Type of DME (sequence of event recorder, fault recorder, or dynamic disturbance recorder).	GO		TO		
PRC-018-1	R3.2.	Make and model of equipment.	GO		TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
PRC-018-1	R3.3.	Installation location.	GO		TO		
PRC-018-1	R3.4.	Operational status.	GO		TO		
PRC-018-1	R3.5.	Date last tested.	GO		TO		
PRC-018-1	R3.6.	Monitored elements, such as transmission circuit, bus section, etc.	GO		TO		
PRC-018-1	R3.7.	Monitored devices, such as circuit breaker, disconnect status, alarms, etc.	GO		TO		
PRC-018-1	R3.8.	Monitored electrical quantities, such as voltage, current, etc.	GO		TO		
PRC-018-1	R4.	The Transmission Owner and Generator Owner shall each provide Disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements (reliability standard PRC-002 Requirement 4).	GO		TO		
PRC-018-1	R5.	The Transmission Owner and Generator Owner shall each archive all data recorded by DMEs for Regional Reliability Organization-identified events for at least three years.	GO		TO		
PRC-018-1	R6.	Each Transmission Owner and Generator Owner that is required by its Regional Reliability Organization to have DMEs shall have a maintenance and testing program for those DMEs that includes:	GO		TO		
PRC-018-1	R6.1.	Maintenance and testing intervals and their basis.	GO		TO		
PRC-018-1	R6.2.	Summary of maintenance and testing procedures.	GO		TO		
PRC-021-1	R1.	Each Transmission Owner and Distribution Provider that owns a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall annually update its UVLS data to support the Regional UVLS program database. The following data shall be provided to the Regional Reliability Organization for each installed UVLS system:			TO		
PRC-021-1	R1.1.	Size and location of customer load, or percent of connected load, to be interrupted.			TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
PRC-021-1	R1.2.	Corresponding voltage set points and overall scheme clearing times.			TO		
PRC-021-1	R1.3.	Time delay from initiation to trip signal.			TO		
PRC-021-1	R1.4.	Breaker operating times.			TO		
PRC-021-1	R1.5.	Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and Special Protection Systems.			TO		
PRC-021-1	R2.	Each Transmission Owner and Distribution Provider that owns a UVLS program shall provide its UVLS program data to the Regional Reliability Organization within 30 calendar days of a request.			TO		
PRC-022-1	R1.	Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall analyze and document all UVLS operations and Misoperations. The analysis shall include:				TOP	
PRC-022-1	R1.1.	A description of the event including initiating conditions.				TOP	
PRC-022-1	R1.2.	A review of the UVLS set points and tripping times.				TOP	
PRC-022-1	R1.3.	A simulation of the event, if deemed appropriate by the Regional Reliability Organization. For most events, analysis of sequence of events may be sufficient and dynamic simulations may not be needed.				TOP	
PRC-022-1	R1.4.	A summary of the findings.				TOP	
PRC-022-1	R1.5.	For any Misoperation, a Corrective Action Plan to avoid future Misoperations of a similar nature.				TOP	
PRC-022-1	R2.	Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall provide documentation of its analysis of UVLS program performance to its Regional Reliability Organization within 90				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		calendar days of a request.					
TOP-001-1	R1.	Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.				TOP	
TOP-001-1	R2.	Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.				TOP	Gap identified: covered by new requirement outlined in TOP-001- R7 Comment area.
TOP-001-1	R3.	Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority, or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.		GOP		TOP	
TOP-001-1	R5.	Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real-time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.				TOP	Gap identified: covered by new requirement outlined in TOP-001- R7 Comment area.
TOP-001-1	R6.	Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.		GOP		TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
TOP-001-1	R7.	Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities, <a href="#">including the Generator Interconnection Facility</a> , from service if removing those facilities would burden neighboring systems unless:		GOP		TOP	<p>Need to add new requirements to address interconnection facilities:  <a href="#">Add R9 as follows:</a>  <a href="#">R9. The Generator Operator shall coordinate the operation of its Generator Interconnection Facility with the Transmission Operator to whom it interconnects in order to preserve Interconnection reliability with respect to the following:</a></p> <ul style="list-style-type: none"> <li>• <a href="#">Switching elements</a></li> <li>• <a href="#">Outage planning</a></li> <li>• <a href="#">Real-time or anticipated emergency conditions</a></li> <li>• <a href="#">Other conditions mutually agreed upon by the Generator Operator and Transmission Operator</a></li> </ul> <p><a href="#">Add R10 as follows:</a>  <a href="#">R10. The Transmission Operator shall have decision-making authority over operation of the Generator Interconnection Operational Interface at all times in order to preserve Interconnection reliability.</a></p>
TOP-001-1	R7.1.	For a generator outage, <a href="#">including the Generator Interconnection Facility</a> , the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.		GOP		TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
TOP-001-1	R7.2.	For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.				TOP	
TOP-001-1	R7.3.	When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.		GOP		TOP	
TOP-001-1	R8.	During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.				TOP	
TOP-002-2	R1.	Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.				TOP	
TOP-002-2	R2.	Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		are aware of the planning purpose.					
TOP-002-2	R3.	Each Load-Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations, <a href="#">including for the Generator Interconnection Facility</a> , with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.		GOP			
TOP-002-2	R4.	Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.				TOP	
TOP-002-2	R5.	Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.				TOP	
TOP-002-2	R6.	Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.				TOP	
TOP-002-2	R10.	Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).				TOP	



Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
TOP-002-2	R11.	The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.				TOP	
TOP-002-2	R13.	At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.		GOP			
TOP-002-2	R14.	Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:		GOP			
TOP-002-2	R14.1.	Changes in real output capabilities.		GOP			
TOP-002-2	R14.2.	Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)		GOP			Add R14.3 as follows: <a href="#">Changes in Generator Interconnection Facility Status</a>
TOP-002-2	R15.	Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).		GOP			
TOP-002-2	R16.	Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to:				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
TOP-002-2	R16.1.	Changes in transmission facility status.				TOP	
TOP-002-2	R16.2.	Changes in transmission facility rating.				TOP	
TOP-002-2	R17.	Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.				TOP	
TOP-002-2	R18.	Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers, and Load-Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network <a href="#">and for the Generator Interconnection Facility</a> .		GOP		TOP	
TOP-002-2	R19.	Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.				TOP	
TOP-003-0	R1.	Generator Operators and Transmission Operators shall provide planned outage information, <a href="#">including information for the Generator Interconnection Facility</a> .		GOP		TOP	
TOP-003-0	R1.1.	Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW) <a href="#">or for the Generator Interconnection Facility</a> . The Transmission Operator shall establish the outage reporting requirements.		GOP		TOP	
TOP-003-0	R1.2.	Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements.				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
TOP-003-0	R1.3.	Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.				TOP	
TOP-003-0	R2.	Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.		GOP		TOP	
TOP-003-0	R3.	Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.		GOP		TOP	
TOP-004-2	R1.	Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).				TOP	To close gap for GOP operation of its Generator Interconnection Facilities, a new requirement is needed: <a href="#">Add R7 as follows:</a> <a href="#">Rx. The Generator Operator shall operate its Generator Interconnection Facility within its applicable ratings.</a>
TOP-004-2	R2.	Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.				TOP	
TOP-004-2	R3.	Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.				TOP	
TOP-004-2	R4.	If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		limits within 30 minutes.					
TOP-004-2	R5.	Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.				TOP	
TOP-004-2	R6.	Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including:				TOP	
TOP-004-2	R6.1.	Monitoring and controlling voltage levels and real and reactive power flows.				TOP	
TOP-004-2	R6.2.	Switching transmission elements.				TOP	
TOP-004-2	R6.3.	Planned outages of transmission elements.				TOP	
TOP-004-2	R6.4.	Responding to IROL and SOL violations.				TOP	
TOP-005-1.1	R1.	Each Transmission Operator and Balancing Authority shall provide its Reliability Coordinator with the operating data that the Reliability Coordinator requires to perform operational reliability assessments and to coordinate reliable operations within the Reliability Coordinator Area.				TOP	
TOP-005-1.1	R3.	Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		Transmission Operators with immediate responsibility for operational reliability.					
TOP-006-1	R1.	Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use.				TOP	
TOP-006-1	R1.1.	Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use.		GOP			
TOP-006-1	R1.2.	Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.				TOP	
TOP-006-1	R2.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.				TOP	
TOP-006-1	R3.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel.				TOP	
TOP-006-1	R4.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern.				TOP	
TOP-006-1	R5.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
TOP-006-1	R6.	Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.				TOP	
TOP-006-1	R7.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.				TOP	
TOP-007-0	R1.	A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits.				TOP	
TOP-007-0	R2.	Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.				TOP	
TOP-007-0	R3.	A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R 2.				TOP	
TOP-008-1	R1.	The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.				TOP	
TOP-008-1	R2.	Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.				TOP	
TOP-008-1	R3.	The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time				TOP	Add companion GOP requirement to ensure clarity: <a href="#">Add R5 as follows:</a> <a href="#">R5. The Generator Operator shall disconnect the Generator Interconnection Facility when safety is</a>

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		permits, otherwise, immediately thereafter.					<a href="#">jeopardized or the overload or abnormal voltage or reactive condition persists and generating equipment or the Generator Interconnection Facility is endangered. In doing so, the Generator Operator shall notify its Transmission Operator and Balancing Authority impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.</a>
TOP-008-1	R4.	The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.				TOP	
VAR-001-1	R1.	Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators.				TOP	
VAR-001-1	R2.	Each Transmission Operator shall acquire sufficient reactive resources within its area to protect the voltage levels under normal and Contingency conditions. This includes the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.				TOP	
VAR-001-1	R3.	The Transmission Operator shall specify criteria that exempts generators from compliance with the requirements defined in Requirement 4, and Requirement 6.1.				TOP	
VAR-001-1	R3.1.	Each Transmission Operator shall maintain a list of generators in its area that are exempt from following a voltage or Reactive Power schedule.				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
VAR-001-1	R3.2.	For each generator that is on this exemption list, the Transmission Operator shall notify the associated Generator Owner.				TOP	
VAR-001-1	R4.	Each Transmission Operator shall specify a voltage or Reactive Power schedule at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (AVR in service and controlling voltage).				TOP	
VAR-001-1	R6.	The Transmission Operator shall know the status of all transmission Reactive Power resources, including the status of voltage regulators and power system stabilizers.				TOP	
VAR-001-1	R6.1.	When notified of the loss of an automatic voltage regulator control, the Transmission Operator shall direct the Generator Operator to maintain or change either its voltage schedule or its Reactive Power schedule.				TOP	
VAR-001-1	R7.	The Transmission Operator shall be able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow.				TOP	
VAR-001-1	R8.	Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – including reactive generation scheduling; transmission line, <a href="#">Generator Interconnection Facility</a> , and reactive resource switching; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits.				TOP	
VAR-001-1	R9.	Each Transmission Operator shall maintain reactive resources to support its voltage under first Contingency conditions.				TOP	
VAR-001-1	R9.1.	Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when Contingencies occur.				TOP	



Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
VAR-001-1	R10.	Each Transmission Operator shall correct IROL or SOL violations resulting from reactive resource deficiencies (IROL violations must be corrected within 30 minutes) and complete the required IROL or SOL violation reporting.				TOP	
VAR-001-1	R11.	After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes.				TOP	
VAR-001-1	R12.	The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.				TOP	
VAR-002-1.1a	R1.	The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.		GOP			
VAR-002-1.1a	R2.	Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings. [1] as directed by the Transmission Operator		GOP			
VAR-002-1.1a	R2.1.	When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.		GOP			
VAR-002-1.1a	R2.2.	When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.		GOP			
VAR-002-1.1a	R3.	Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:		GOP			

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
VAR-002-1.1a	R3.1.	A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.		GOP			
VAR-002-1.1a	R3.2.	A status or capability change on any other Reactive Power resources under the Generator Operator's control, <a href="#">including the Generator Interconnection Facility</a> , and the expected duration of the change in status or capability.		GOP			
VAR-002-1.1a	R4.	The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.	GO				
VAR-002-1.1a	R4.1.	For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:	GO				
VAR-002-1.1a	R4.1.1.	Tap settings.	GO				
VAR-002-1.1a	R4.1.2.	Available fixed tap ranges.	GO				
VAR-002-1.1a	R4.1.3.	Impedance data.	GO				
VAR-002-1.1a	R4.1.4.	The +/- voltage range with step-change in % for load-tap changing transformers.	GO				
VAR-002-1.1a	R5.	After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement.	GO				
VAR-002-1.1a	R5.1.	If the Generator Operator can't comply with the Transmission Operator's specifications, the Generator Operator shall notify the Transmission Operator and shall provide the technical justification.		GOP			



## **Appendix 2 — Proposed Revisions to the Statement of Compliance Registry Criteria**

# Statement of Compliance Registry Criteria (Revision 6.0)

## Summary

Since becoming the Electric Reliability Organization (ERO), NERC has initiated a program to identify candidate organizations for its compliance registry. The program, conducted by NERC and the Regional Entities<sup>5</sup>, will also confirm the functions and information now on file for currently-registered organizations. NERC and the Regional Entities have the obligation to identify and register all entities that meet the criteria for inclusion in the compliance registry, as further explained in the balance of this document.

This document describes how NERC will identify organizations that may be candidates for registration and assign them to the compliance registry.

Organizations will be responsible to register and to comply with approved reliability standards to the extent that they are owners, operators, and users of the bulk power system, perform a function listed in the functional types identified in Section II of this document, and are material to the reliable operation of the interconnected bulk power system as defined by the criteria and notes set forth in this document. NERC will apply the following principles to the compliance registry:

- In order to carry out its responsibilities related to enforcement of Reliability Standards, NERC must identify the owners, operators, and users of the bulk power system who have a material impact<sup>6</sup> on the bulk power system through a compliance registry. NERC and the Regional Entities will make their best efforts to identify all owners, users and operators who have a material reliability impact on the bulk power system in order to develop a complete and current registry list. The registry will be updated as required and maintained on an on-going basis.
- Organizations listed in the compliance registry are responsible and will be monitored for compliance with applicable mandatory reliability standards. They will be subject to NERC's and the Regional Entities' compliance and enforcement programs.
- NERC and Regional Entities will not monitor nor hold those not in the registry responsible for compliance with the standards. An entity which is not initially placed on the registry, but which is identified subsequently as having a material reliability impact, will be added to the registry. Such entity will not be subject to a sanction or penalty by NERC or the Regional Entity for actions or inactions prior to being placed

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<sup>5</sup> The term "Regional Entities" includes Cross-Border Regional Entities.

<sup>6</sup> The criteria for determining whether an entity will be placed on the registry are set forth in the balance of this document. At any time a person may recommend in writing, with supporting reasons, to the director of compliance that an organization be added to or removed from the compliance registry, pursuant to NERC ROP 501.1.3.5.

on the registry, but may be required to comply with a remedial action directive or mitigation plan in order to become compliant with applicable standards. After such entity has been placed on the compliance registry, it shall be responsible for

complying with Reliability Standards and may be subject to sanctions or penalties as well as any remedial action directives and mitigation plans required by the Regional Entities or NERC for future violations, including any failure to follow a remedial action directive or mitigation plan to become compliant with Reliability Standards.

- Required compliance by a given organization with the standards will begin the later of (i) inclusion of that organization in the compliance registry and (ii) approval by the appropriate governmental authority of mandatory reliability standards applicable to the entity.

Entities responsible for funding NERC and the Regional Entities have been identified in the budget documents filed with FERC. Presence on or absence from the compliance registry has no bearing on an entity's independent responsibility for funding NERC and the Regional Entities.

## **Background**

In 2005, NERC and the Regional Entities conducted a voluntary organization registration program limited to balancing authorities, planning authorities, regional reliability organizations, reliability coordinators, transmission operators, and transmission planners. The list of the entities that were registered constitutes what NERC considered at that time as its compliance registry.

NERC has recently initiated a broader program to identify additional organizations potentially eligible to be included in the compliance registry and to confirm the information of organizations currently on file. NERC believes this is a prudent activity at this time because:

- As of July 20, 2006, NERC was certified as the ERO created for the U.S. by the Energy Policy Act of 2005 (EPAct) and FERC Order 672. NERC has also filed with Canadian authorities for similar recognition in their respective jurisdictions.
- FERC's Order 672 directs that owners, operators and users of the bulk power system shall be registered with the ERO and the appropriate Regional Entities.
- As the ERO, NERC has filed its current reliability standards with FERC and with Canadian authorities. As accepted and approved by FERC and appropriate Canadian authorities, the reliability standards are no longer voluntary, and organizations that do not fully comply with them may face penalties or other sanctions determined and levied by NERC or the Regional Entities.
- NERC's reliability standards include compliance requirements for additional reliability function types beyond the six types registered by earlier registration programs.
- Based on selection as the ERO, the extension and expansion of NERC's current registration program<sup>7</sup> is the means by which NERC and the Regional Entities will plan, manage and execute reliability standard compliance oversight of owners, operators, and users of the bulk power system.

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<sup>7</sup> See: NERC ERO Application; Exhibit C; Section 500 – Organization Registration and Certification.

- Organizations listed in the compliance registry are subject to NERC's and the Regional Entities' compliance and enforcement programs.

### **Statement of Issue**

As the ERO, NERC intends to comprehensively and thoroughly protect the reliability of the grid. To support this goal NERC will include in its compliance registry each entity that NERC concludes can materially impact the reliability of the bulk power system. However, the potential costs and effort of ensuring that every organization potentially within the scope of "owner, operator, and user of the bulk power system" becomes registered while ignoring their impact upon reliability, would be disproportionate to the improvement in reliability that would reasonably be anticipated from doing so.

NERC wishes to identify as many organizations as possible that may need to be listed in its compliance registry. Identifying these organizations is necessary and prudent at this time for the purpose of determining resource needs, both at the NERC and Regional Entity level, and to begin the process of communication with these entities regarding their potential responsibilities and obligations. NERC and the Regional Entities believe that primary candidate entities can be identified at this time, while other entities can be identified later, as and when needed. Selection principles and criteria for the identification of these initial entities are required. This list will become the "Initial Non-binding Organization Registration List". With FERC having made the approved Reliability Standards enforceable, this list becomes the NERC Compliance Registry.

### **Resolution**

NERC and the Regional Entities have identified two principles they believe are key to the entity selection process. These are:

1. There needs to be consistency between regions and across the continent with respect to which entities are registered, and;
2. Any entity reasonably deemed material to the reliability of the bulk power system will be registered, irrespective of other considerations.

To address the second principle the Regional Entities, working with NERC, will identify and register any entity they deem material to the reliability of the bulk power system.

In order to promote consistency, NERC and the Regional Entities intend to use the following criteria as the basis for determining whether particular entities should be identified as candidates for registration. All organizations meeting or exceeding the criteria will be identified as candidates.

The following four groups of criteria (Sections I-IV) plus the statements in Section V will provide guidance regarding an entity's registration status:

- Section I determines if the entity is an owner, operator, or user of the bulk power system and, hence, a candidate for organization registration.

- Section II uses NERC’s current functional type definitions to provide an initial determination of the functional types for which the entities identified in Section I should be considered for registration.
- Section III lists the criteria regarding smaller entities; these criteria can be used to forego the registration of entities that were selected to be considered for registration pursuant to Sections I and II and, if circumstances change, for later removing entities from the registration list that no longer meet the relevant criteria.
- Section IV — additional criteria for joint registration. Joint registration criteria may be used by Joint Action Agencies, Generation and Transmission Cooperatives and other entities which agree upon a clear division of compliance responsibility for Reliability Standards by written agreement. Pursuant to FERC’s directive in paragraph 107 of Order No. 693, rules pertaining to joint registration and Joint Registration Organizations will now be found in Sections 501 and 507 of the NERC Rules of Procedure.

I. Entities that use, own or operate elements of the bulk electric system as established by NERC’s approved definition of bulk electric system below are (i) owners, operators, and users of the bulk power system and (ii) candidates for registration:

*“As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.”<sup>8</sup>*

II. Entities identified in Part I above will be categorized as registration candidates who may be subject to registration under one or more appropriate functional entity types based on a comparison of the functions the entity normally performs against the following function type definitions:

<b>Function Type</b>	<b>Acronym</b>	<b>Definition/Discussion</b>
Balancing Authority	BA	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a BA area, and supports Interconnection frequency in real-time.
Distribution Provider	DP	Provides and operates the “wires” between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the DP. Thus, the DP is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.

<sup>8</sup> However, ownership of radial transmission facilities intended to be covered by the vegetation management standard (applicable to transmission lines 200 kV and above) would be included in this definition.

<b>Function Type</b>	<b>Acronym</b>	<b>Definition/Discussion</b>
Generator Operator	GOP	The entity that operates generating unit(s) <a href="#">and the Generator Interconnection Facility</a> and performs the functions of supplying energy and interconnected operations services.
Generator Owner	GO	Entity that owns and maintains generating units, <a href="#">including its Generator Interconnection Facility</a> .
Interchange Authority	IA	The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.
Load-Serving Entity	LSE	Secures energy and transmission service (and related interconnected operations services) to serve the electrical demand and energy requirements of its end-use customers.
Planning Authority	PA	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
Purchasing-Selling Entity	PSE	The entity that purchases or sells and takes title to energy, capacity, and interconnected operations services. PSE may be affiliated or unaffiliated merchants and may or may not own generating facilities.
Reliability Coordinator	RC	The entity that is the highest level of authority who is responsible for the reliable operation of the bulk power system, has the wide area view of the bulk power system, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The RC has the purview that is broad enough to enable the calculation of interconnection reliability operating limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
Reserve Sharing Group	RSG	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each BA's use in recovering from contingencies within the group. Scheduling energy from an adjacent BA to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker, (e.g., between zero and ten minutes) then, for the purposes of disturbance control performance, the areas become a RSG.



<b>Function Type</b>	<b>Acronym</b>	<b>Definition/Discussion</b>
Resource Planner	RP	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a PA area.
Transmission Owner	TO	The entity that owns and maintains transmission facilities.
Transmission Operator	TOP	The entity responsible for the reliability of its local transmission system and operates or directs the operations of the transmission facilities.
Transmission Planner	TP	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the PA area.
Transmission Service Provider	TSP	The entity that administers the transmission tariff and provides transmission service to transmission customers under applicable transmission service agreements.

III. Entities identified in Part II above as being subject to registration as an LSE, DP, GO, GOP, TO, or TOP should be excluded from the registration list for these functions if they do not meet any of the criteria listed below:

III(a) Load-serving Entity:

Electrical load must be accounted for at the bulk power system level to properly plan and account for the load in the operation of the bulk power system. Load-serving entities will be registered regardless of whether they own or operate physical power system assets<sup>9</sup> as follows:

- III.a.1 Load-serving entity owning and/or operating physical power system assets whose peak load is > 25 MW and load is otherwise unaccounted for by another registered Load-serving entity as described in the exclusion below, or;
- III.a.2 Load-serving entity not owning and/or operating physical power system assets whose peak load is > 25 MW and load is otherwise unaccounted for by another registered Load-serving entity as described in the exclusion below, or;
- III.a.3 Load-serving entity is designated as the responsible entity for facilities that are part of a required underfrequency load shedding (UFLS) program

<sup>9</sup> Entities not owning and/or operating physical power system assets that are responsible for serving retail end-use loads will not be required to comply with reliability standards related to asset ownership or operation.

designed, installed, and operated for the protection of the bulk power system, or;

- III.a.4 Load-serving entity is designated as the responsible entity for facilities that are part of a required undervoltage load shedding (UVLS) program designed, installed, and operated for the protection of the bulk power system.

*[Exclusion: A load-serving entity will not be registered based on these criteria if responsibilities for compliance with approved NERC reliability standards or associated requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, such as a load-serving entity, balancing authority, transmission operator, G&T cooperative or joint action agency as described in Sections 501 and 507 of the NERC Rules of Procedure.]*

III(b) Distribution Provider:

- III.b.1 Distribution provider system serving >25 MW of peak load that is directly connected to the bulk power system.

*[Exclusion: A distribution provider will not be registered based on this criterion if responsibilities for compliance with approved NERC reliability standards or associated requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, such as a load-serving entity, balancing authority, transmission operator, G&T cooperative, or joint action agency as described in Sections 501 and 507 of the NERC Rules of Procedure.]* or;

- III.b.2 Distribution provider is the responsible entity that owns, controls, or operates facilities that are part of any of the following protection systems or programs designed, installed, and operated for the protection of the bulk power system:

- a required UFLS program.
- a required UVLS program.
- a required special protection system.
- a required transmission protection system.

*[Exclusion: A distribution provider will not be registered based on these criteria if responsibilities for compliance with approved NERC reliability standards or associated requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, such as a load-serving entity, balancing authority, transmission operator, G&T cooperative, or joint action agency as described in Sections 501 and 507 of the NERC Rules of Procedure.]*

### III(c) Generator Owner/Operator:

- III.c.1 Individual generating unit > 20 MVA (gross nameplate rating) and is directly connected to the bulk power system, or;
- III.c.2 Generating plant/facility > 75 MVA (gross aggregate nameplate rating) or when the entity has responsibility for any facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation above 75 MVA gross nameplate rating, or;
- III.c.3 Any generator, regardless of size, that is a blackstart unit material to and designated as part of a transmission operator entity's restoration plan, or;
- III.c.4 Any generator, regardless of size, that is material to the reliability of the bulk power system.

*[Exclusions:*

*A generator owner/operator will not be registered based on these criteria if responsibilities for compliance with approved NERC reliability standards or associated requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, such as a load-serving entity, G&T cooperative or joint action agency as described in Sections 501 and 507 of the NERC Rules of Procedure.*

*As a general matter, a customer-owned or operated generator/generation that serves all or part of retail load with electric energy on the customer's side of the retail meter may be excluded as a candidate for registration based on these criteria if (i) the net capacity provided to the bulk power system does not exceed the criteria above or the Regional Entity otherwise determines the generator is not material to the bulk power system and (ii) standby, back-up and maintenance power services are provided to the generator or to the retail load pursuant to a binding obligation with another generator owner/operator or under terms approved by the local regulatory authority or the Federal Energy Regulatory Commission, as applicable.*

*For purposes of applying these criteria, the Generator Interconnection Facility is considered as though part of the generating facility. The Generator Interconnection Facility is defined to be:*

*“ Sole-use facility for the purpose of connecting the generating unit(s) to the transmission grid. In this regard, the sole-use facility only transmits power associated with the interconnecting generator, whether delivered to the grid or delivered to the generator for station service or auxiliary load, or delivered to meet cogeneration load requirements.”*]

### III(d) Transmission Owner/Operator:

III.d.1 An entity that owns/operates an integrated transmission element associated with the bulk power system 100 kV and above, or lower voltage as defined by the Regional Entity necessary to provide for the reliable operation of the interconnected transmission grid; or

III.d.2 An entity that owns/operates a transmission element below 100 kV associated with a facility that is included on a critical facilities list that is defined by the Regional Entity.

*[Exclusion: A transmission owner/operator will not be registered based on these criteria if responsibilities for compliance with approved NERC reliability standards or associated requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, such as a load-serving entity, G&T cooperative or joint action agency as described in Sections 501 and 507 of the NERC Rules of Procedure.*

*In addition, a Generator Interconnection Facility as defined in Section III.c.4 is not considered an integrated transmission element for purposes of applying these criteria. ]*

#### IV. Joint Registration Organization and applicable Member Registration.

Pursuant to FERC's directive in paragraph 107 of Order No. 693, NERC's rules pertaining to joint registrations and Joint Registration Organizations are now found in Section 501 and 507 of the NERC Rules of Procedure.


V. If NERC or a Regional Entity encounters an organization that is not listed in the compliance registry, but which should be subject to the reliability standards, NERC or the Regional Entity is obligated and will add that organization to the registry, subject to that organization's right to challenge as provided in Section 500 of NERC's Rules of Procedure and as described in Note 3 below.

#### Notes to the above Criteria

1. The above are general criteria only. The Regional Entity considering registration of an organization not meeting (e.g., smaller in size than) the criteria may propose registration of that organization if the Regional Entity believes and can reasonably demonstrate<sup>10</sup> that the organization is a bulk power system owner, or operates, or uses bulk power system assets, and is material to the reliability of the bulk power system. Similarly, the Regional Entity may exclude an organization that meets the criteria described above as a candidate for registration if it believes and can reasonably demonstrate to NERC that the bulk power system owner, operator, or user does not have a material impact on the reliability of the bulk power system.

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<sup>10</sup> The reasonableness of any such demonstration will be subject to review and remand by NERC itself, or by any agency having regulatory or statutory oversight of NERC as the ERO (e.g., FERC or appropriate Canadian authorities).

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2. An organization not identified using the criteria, but wishing to be registered, may request that it be registered. For further information refer to: NERC Rules of Procedure, Section 500 – Organization Registration and Certification; Part 1.3.
  3. An organization may challenge its registration within the compliance registry. NERC or the Regional Entity will provide the organization with all information necessary to timely challenge that determination including notice of the deadline for contesting the determination and the relevant procedures to be followed as described in the NERC Rules of Procedure; Section 500 – Organization Registration and Certification.
  4. If an entity is part of a class of entities excluded based on the criteria above as individually being unlikely to have a material impact on the reliability of the bulk power system, but that in aggregate have been demonstrated to have such an impact it may be registered for applicable standards and requirements irrespective of other considerations.



## **Appendix 3 — Proposed Standards Authorization Request and Redline Standard Revisions**

*E-mail completed form to  
[maureen.long@nerc.net](mailto:maureen.long@nerc.net)*

## Standard Authorization Request Form

Title of Proposed Standard	Various Standards Containing GO/GOP and TO/TOP Requirements
Request Date	<del>October 30, 2009</del> <a href="#">November 16, 2009</a>
SC Approval Date	

<b>SAR Requester Information</b>	<b>SAR Type</b> ( <i>Check a box for each one that applies.</i> )
Name            Ad Hoc Group for Generator Requirements at the Transmission Interface	<input type="checkbox"/> New Standard
Primary Contact    Scott Helyer	<input checked="" type="checkbox"/> Revision to existing Standard
Telephone    817-462-1512 Fax	<input type="checkbox"/> Withdrawal of existing Standard
E-mail            shelyer@tnsk.com	<input type="checkbox"/> Urgent Action

## Standards Authorization Request Form

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**Purpose** (Describe what the standard action will achieve in support of bulk power system reliability.)

The proposed changes to the requirements and the addition of new requirements will add significant clarity to Generator Owners and Generator Operators regarding their reliability standard obligations at the interface with the interconnected grid.

**Industry Need** (Provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

Significant industry concern exists regarding the application of Transmission Owner and Transmission Operator requirements, and more generally, to the registration of Generator Owners and Generator Operators as Transmission Owners and Transmission Operators, based on the facilities that connect the generators to the interconnected grid. The final report of the Ad Hoc Group for Generator Requirements at the Transmission Interface evaluated the issue and proposes a number of changes that adds much needed clarity on the requirements for Generator Interconnection Facilities. Absent these revisions and additional requirements, Generator Owners and Generator Operators are subject to what some believe to be inappropriate registration as Transmission Owners and Transmission Operators to ensure coverage for certain reliability requirements. The modifications and additions recommended wholly and directly address the requirements for Generator Owners and Generator Operators regarding its Generator Interconnection Facilities, and add particular focus on the operation of the interface point at which operating responsibility shifts from the GEnerator Operator to the Transmission Operator.

The proposal also modifies certain of NERC's existing glossary terms and adds new terms to support the standards modifications.

**Brief Description** (Provide a paragraph that describes the scope of this standard action.)

32 NERC Reliability Standards contain language regarding generators or generating facilities for which greater clarity regarding its Generator Interconnection Facilities would ensure no reliability gap exists

12 requirements in FAC-003-1 - Transmission Vegetation Management should have their applicability expanded to include Generator Owners.

2 NERC Reliability Standards should have their applicability expanded to include Generator Operators to address general reliability gaps not attributable to their Generator Interconnection Facilities.

8 new Reliability Standard Requirements should be added to ensure the responsibilities for owning and operating the Generator Interconnection Facility are clear, and to address certain requirements that should apply to all generators regardless of interconnection configuration.

New NERC Glossary definitions are needed for Generator Interconnection Facility and Generator Interconnection Operational Interface, as well as modifications to Vegetation Inspection, Right-of-Way, Generator Owner, Generator Operator, and Transmission

**Detailed Description** (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.)

Refer to Final Report of the Ad hoc Group for Generator Requirements at the Transmission Interface.



## Standards Authorization Request Form

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Revisions to the latest versions of the following standards are included in the report and redline standard changes are included to accompany this SAR:

BAL-005

CIP-002

EOP-001, -003, -004, -008

FAC-001, -003, -008, -009

IRO-005

MOD-010, -012

PER-001, -002

PRC-001, -004, -005

TOP-001, -002, -003, -004, -008

VAR-001, -002

**Standards Authorization Request Form**

**Reliability Functions**

<b>The Standard will Apply to the Following Functions</b> <i>(Check box for each one that applies.)</i>		
<input type="checkbox"/>	Reliability Assurer	Monitors and evaluates the activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the bulk power system within a Reliability Assurer Area and adjacent areas.
<input type="checkbox"/>	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
<input type="checkbox"/>	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
<input type="checkbox"/>	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
<input type="checkbox"/>	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
<input type="checkbox"/>	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within its portion of the Planning Coordinator's Area.
<input checked="" type="checkbox"/>	Transmission Owner	Owns and maintains transmission facilities.
<input checked="" type="checkbox"/>	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
<input type="checkbox"/>	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within the Transmission Planner Area.
<input type="checkbox"/>	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
<input type="checkbox"/>	Distribution Provider	Delivers electrical energy to the End-use customer.
<input checked="" type="checkbox"/>	Generator Owner	Owns and maintains generation facilities.
<input checked="" type="checkbox"/>	Generator Operator	Operates generation unit(s) to provide real and reactive power.
<input type="checkbox"/>	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
<input type="checkbox"/>	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

## Standards Authorization Request Form

### **Reliability and Market Interface Principles**

<b>Applicable Reliability Principles</b> <i>(Check box for all that apply.)</i>	
<input checked="" type="checkbox"/>	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
<input type="checkbox"/>	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
<input checked="" type="checkbox"/>	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
<input checked="" type="checkbox"/>	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
<input checked="" type="checkbox"/>	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
<input checked="" type="checkbox"/>	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
<input type="checkbox"/>	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
<input type="checkbox"/>	8. Bulk power systems shall be protected from malicious physical or cyber attacks.
<b>Does the proposed Standard comply with all of the following Market Interface Principles?</b> <i>(Select 'yes' or 'no' from the drop-down box.)</i>	
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes	
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes	
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes	
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes	

**Standards Authorization Request Form**

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***Related Standards***

<b>Standard No.</b>	<b>Explanation</b>

***Related SARs***

<b>SAR ID</b>	<b>Explanation</b>

***Regional Variances***

<b>Region</b>	<b>Explanation</b>
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

## Unofficial Comment Form for Generator Requirements at the Transmission Interface — Project 2010-07

Please **DO NOT** use this form to submit comments. Please use the [electronic form](#) located at the link below to submit comments on the proposed SAR and modifications to several reliability standards and NERC Glossary terms associated with the recommendations of the Generator Requirements at the Transmission Interface Ad Hoc Group, embodied in Project 2010-07. Comments must be submitted by **March 15, 2010**. If you have questions please contact David Taylor at [david.taylor@nerc.net](mailto:david.taylor@nerc.net) or by telephone at (609) 651-5089.

[http://www.nerc.com/filez/standards/Project2010-07\\_GOTO\\_Project.html](http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html)

### Background Information:

On January 14, 2008, the NERC Board of Trustees Compliance Committee rendered a decision upholding the Western Electricity Coordinating Council's (WECC's) determination to register the New Harquahala Generating Company ("Harquahala") as a Transmission Owner and Transmission Operator. This determination is based on Harquahala's 26-mile 500 kV interconnection facilities that connect the plant with the Hassayampa transmission substation. This decision was upheld by FERC and caused concern for generator owners and generator operators who owned only transmission "tie-line" facilities used to connect their generating facilities to a transmission substation.

In response to concerns from members of the generator segment regarding this decision, NERC undertook a survey in the Fall of 2008 to clearly define stakeholders concerns; to review and highlight those transmission owner and transmission operator requirements that should be considered for generic applicability for generator owners and generator operators for their tie-line facilities; and to collect ideas for resolving the generator owner and generator operator concerns.

There were wide-ranging viewpoints to the topic from the over 100 respondents but there was no support for merely assigning all transmission owner and transmission operator requirements to the generator owner and generator operator solely on the basis of owning interconnection facilities. One consistent suggestion was to assemble a group of industry representatives to analyze and make recommendations for resolving the concerns, thereby establishing general criteria for determining whether generator owners and generator operators should be registered for transmission owner and transmission operator requirements in NERC's reliability standards.

Accordingly, in February, 2009, NERC announced the formation of the Ad Hoc Group for Generator Requirements at the Transmission Interface. Its objective was to:

"Evaluate existing NERC Reliability Standard requirements and develop a recommendation and possible standards authorization request to address gaps in reliability for interconnection facilities of the Generator Owner and expectations for the Generator Operator in operating those facilities. Propose strategies to address or resolve other related issues as appropriate."

In November, 2009, the group published its final report that included the following conclusions and recommendations:

## Conclusions

1. Generator Interconnection Facilities operating at a voltage of 100 kV or greater or those deemed critical to the Bulk Electric System by the Regional Entity makes the Generator Interconnection Facility part of the Bulk Electric System for purposes of applying Generator Owner and Generator Operator requirements but not for applying Transmission Owner or Transmission Operator requirements.
2. The Generator Owner or Generator Operator that owns and/or operates a Generator Interconnection Facility, that is, a sole-use facility that interconnects the generator to the grid, should not be registered as a Transmission Owner or Transmission Operator by virtue of owning or operating its Generator Interconnection Facility.
3. A Generator Interconnection Facility is considered as though part of the generating facility specifically for purposes of applying Reliability Standards to a Generator Owner or Generator Operator.
4. Changes to NERC Reliability Standards are needed to ensure complete reliability coverage of the Generator Interconnection Facility.
  - a. 32 NERC Reliability Standard requirements contain language regarding generators or generating facilities for which greater clarity regarding its Generator Interconnection Facilities would ensure that no reliability gap exists.
  - b. 12 requirements in FAC-003-1 – Transmission Vegetation Management should have their applicability expanded to include Generator Owners.
  - c. 2 NERC Reliability Standards should have their applicability expanded to include Generator Operators to address general reliability gaps not attributable to the Generator Interconnection Facility.
  - d. 8 new Reliability Standard requirements should be added to ensure the responsibilities for owning and operating the Generator Interconnection Facility are clear, and to address certain requirements that should apply to all generators regardless of interconnection configuration.
5. If a generator is connected to multiple transmission facilities that are subject to network power flows (that is, power flow on these multiple transmission facilities includes power not solely associated with the generator output, requirements for station service, auxiliary load, or cogeneration load), then those transmission facilities are integrated transmission facilities and should be subjected to the applicable Transmission Owner and Transmission Operator Standard Requirements<sup>1</sup>.
6. After review of the existing Transmission Owner requirements that are not currently applicable to Generator Owners, only FAC-003-1 should have its applicability expanded to include Generator Owners as a result of the Generator Interconnection Facility, if the length of the Generator Interconnection Facility exceeds two spans (generally, more than one-half mile) from the generator property line.
7. After review of the existing Transmission Operator requirements that are not currently applicable to Generator Operators, no existing Transmission Operator requirements should apply to Generator Operators as a result of the Generator Interconnection Facility.

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<sup>1</sup> 1 A double-circuit line behind the point of interconnection, for example, that is carrying power solely associated with the generation output, requirements for station service, auxiliary load, or cogeneration load, would not be considered an integrated transmission facility by comparison.

8. New NERC Glossary definitions are needed for Generator Interconnection Facility and Generator Interconnection Operational Interface, as well as modifications to the terms Vegetation Inspection, Right-of-Way, Generator Owner, Generator Operator, and Transmission.

### **Recommendations**

1. Submit Standards Authorization Requests (SARs) requesting expeditious action to add or modify the definitions in NERC's Glossary for Generator Interconnection Facility and Generator Interconnection Operational Interface, as well as modifications to the terms Vegetation Inspection, Right-of-Way, Generator Owner, Generator Operator, and Transmission.
2. Submit SARs requesting expeditious action to modify existing standard requirements to add specificity for Generator Interconnection Facility where appropriate, to add Generator Operator applicability where needed, to add requirements to capture responsibilities for owning and operating the Generator Interconnection Facility, and to add requirements where necessary that should be applicable to Generator Operators regardless of the interconnection configuration.
3. Modify the applicability of FAC-003-1 to apply to Generator Owners when their Generator Interconnection Facility operates at 200 kV or above and exceeds two spans from the generator property line, or otherwise is deemed to be critical to the Bulk Electric System.
4. Modify the NERC Rules of Procedure, NERC Compliance Registry Criteria, and other documents as necessary to reflect that a Generator Owner should not be registered as a Transmission Owner and a Generator Operator should not be registered as a Transmission Operator on the basis of the Generator Interconnection Facility.
5. NERC and the Regional Entities should refrain from further registering Generator Owners and Generator Operators as Transmission Owners and Transmission Operators generically by virtue of the Generator Interconnection Facility.
6. Based on the conclusions and recommendations offered in this report, NERC and the Regional Entities should carefully develop and implement a plan to address de-registering those Generator Owners and Generator Operators that have previously been registered as a Transmission Owner and Transmission Operator by virtue of the Generator Interconnection Facility.

The complete final report is located at the following link:

[http://www.nerc.com/files/GO-TO\\_Final\\_Report\\_Complete\\_2009Nov16.pdf](http://www.nerc.com/files/GO-TO_Final_Report_Complete_2009Nov16.pdf)

Specifically, the following new or revised terms are being proposed for the NERC Glossary and are presented for consideration:

#### **Transmission**

An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems. *Generator Interconnection Facility is not included in this definition.*

#### **Generator Owner**

Entity that owns and maintains generating units, *including its Generator Interconnection Facility.*

#### **Generator Operator**

The entity that operates generating unit(s) and the Generator Interconnection Facility and performs the functions of supplying energy and Interconnected Operations Services. *The Generator Operator also operates the Generator Interconnection Facility and is responsible for coordinating with the Transmission Operator when the facility is energized or about to be energized to/de-energized from the transmission system.*

**Right-of-Way (ROW)**

A corridor of land on which electric lines may be located. *The ~~Transmission Owner~~ owner of the electric lines* may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

**Vegetation Inspection**

The systematic examination of a ~~transmission corridor~~ *Transmission Line or Generator Interconnection Facility Right-of-Way* to document vegetation conditions.

***Generator Interconnection Facility (NEW)***

*Sole-use facility for the purpose of connecting the generating unit(s) to the transmission grid. In this regard, the sole-use facility only transmits power associated with the interconnecting generator, whether delivered to the grid or delivered to the generator for station service or auxiliary load, or delivered to meet cogeneration load requirements.*

***Generator Interconnection Operational Interface (NEW)***

*Location at which operating responsibility for the Generator Interconnection Facility changes between the Transmission Operator and the Generator Operator.*

In addition, the following new requirements are being proposed for inclusion in the Reliability Standards and are included in the respective standards located in Appendix 1 of the final report:

1. The Generator Operator who has responsibility for monitoring the status of a special protection system or remedial action scheme at the generating facility for the benefit of Bulk Electric System reliability should notify the Transmission Operator when a change in status or capability occurs. (IRO-005)
2. Each Generator Operator shall provide its operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Generation Facility and the Generation Interconnection Facility, and to implement directives of the Transmission Operator and Balancing Authority. (PER-001)
3. Each Generator Operator shall implement an initial and continuing training program for all personnel responsible for operating the Generator Interconnection Facility to ensure the ability to operate the equipment in a reliable manner. (Per-002)
4. The Generator Operator shall coordinate the operation of its Generator Interconnection Facility with the Transmission Operator to whom it interconnects to preserve Interconnection reliability. (TOP-001)
5. The Transmission Operator has decision-making authority for the Generator Interconnection Operational Interface. (TOP-001)
6. The Generator Operator shall notify the Transmission Operator of a change in status of the Generation Interconnection Facility.
7. The Generator Operator shall operate the Generation Interconnection Facility within Facility Ratings. (TOP-004)



**Unofficial Comment Form — SAR and Proposed Revisions to Standards and Definitions for Project 2010-07**

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8. The Generator Operator shall disconnect the Generation Interconnection Facility immediately in coordination with the Transmission Operator when time permits or as soon as practical thereafter if an overload or other abnormal condition threatens equipment or personnel safety. (TOP-008)

Finally, Appendix 1 of the final report contains the table of reliability standards reviewed by the ad hoc group pertaining to Generator Owner, Generator Operator, Transmission Owner, and Transmission Operator and the recommended revisions proposed by the ad hoc team therein.

The ad hoc team believes that these modifications to the definitions and requirements, coupled with the proposed revisions to the compliance registration criteria that are identified in the GO-TO Final Report, will result in closing the reliability gap that previously existed where it wasn't clear what entity had responsibility for requirements associated with the facilities that connect generating plants to transmission substations, without placing an undue burden on Generator Owners and Generator Operators.

1. Do you agree that there is a reliability-related need for the proposed standards action?

Yes

No

Comments:

2. Do you agree with the scope of the proposed standards action?

Yes

No

Comments:

3. Do you agree with the proposed NERC Glossary additions or revisions? If you disagree with one or more of the proposed new or modified definitions, please provide a revision that would make the definition acceptable to you.

Yes

No

Comments:

4. Do you agree with the proposed *new* requirements intended to add clarity around expectations for generator owners and operators at the transmission interface?

Yes

No

Comments:

5. Do you agree with the proposed *modified* requirements intended to add clarity around expectations for generator owners and operators at the transmission interface?

Yes

No

**Unofficial Comment Form — SAR and Proposed Revisions to Standards and Definitions for Project 2010-07**

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Comments:

6. Do you believe there are any other Transmission Owner or Transmission Operator standards or requirements that should be applicable to the Generator Owner or Generator Operator other than those identified?

Yes

No

Comments:

7. The next posting of the proposed revisions to these standards will include conforming changes to the measures and compliance elements, and will include an implementation plan. Please identify how much time you feel an entity will need to become fully compliant with the following new/revised requirements:

The Generator Operator who has responsibility for monitoring the status of a special protection system or remedial action scheme at the generating facility for the benefit of Bulk Electric System reliability should notify the Transmission Operator when a change in status or capability occurs. (IRO-005)

Time needed to become fully compliant:

Comments:

a. Each Generator Operator shall provide its operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Generation Facility and the Generation Interconnection Facility, and to implement directives of the Transmission Operator and Balancing Authority. (PER-001)

Time needed to become fully compliant:

Comments:

b. Each Generator Operator shall implement an initial and continuing training program for all personnel responsible for operating the Generator Interconnection Facility to ensure the ability to operate the equipment in a reliable manner. (Per-002)

Time needed to become fully compliant:

Comments:

c. The Generator Operator shall coordinate the operation of its Generator Interconnection Facility with the Transmission Operator to whom it interconnects to preserve Interconnection reliability. (TOP-001)

Time needed to become fully compliant:

Comments:

d. The Transmission Operator has decision-making authority for the Generator Interconnection Operational Interface. (TOP-001)

Time needed to become fully compliant:

Comments:

**Unofficial Comment Form — SAR and Proposed Revisions to Standards and Definitions for Project 2010-07**

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e. The Generator Operator shall notify the Transmission Operator of a change in status of the Generation Interconnection Facility.

Time needed to become fully compliant:

Comments:

f. The Generator Operator shall operate the Generation Interconnection Facility within Facility Ratings. (TOP-004)

Time needed to become fully compliant:

Comments:

g. The Generator Operator shall disconnect the Generation Interconnection Facility immediately in coordination with the Transmission Operator when time permits or as soon as practical thereafter if an overload or other abnormal condition threatens equipment or personnel safety. (TOP-008)

Time needed to become fully compliant:

Comments:

8. If you have any other comments on this SAR or proposed standard revisions and NERC Glossary modifications that you have not already provided in response to the prior questions, please provide them here.

Comments:



NORTH AMERICAN ELECTRIC  
RELIABILITY CORPORATION

## Standards Announcement

Standards Authorization Request (SAR) Comment and Drafting Team  
Nomination Periods Open

Project 2010-07: Generator Requirements at the Transmission Interface

Now available at: [http://www.nerc.com/filez/standards/Project2010-07\\_GOTO\\_Project.html](http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html)

### **Nominations for Drafting Team (through March 1, 2010)**

The Standards Committee is seeking industry experts to serve on the Generator Requirements at the Transmission Interface Drafting Team (see project background below).

If you are interested in serving on this drafting team, please complete this [electronic nomination form](#) by **March 1, 2010**.

### **Comment Period (through March 15, 2010)**

The Standards Committee has posted a proposed SAR for a 30-day comment period **ending on March 15, 2010**. Also posted are proposed revisions to existing standards and a copy of the final report published by the Ad Hoc Group for Generator Requirements at the Transmission Interface.

Please use this [electronic form](#) to submit comments. If you experience any difficulties in using the electronic form, please contact Lauren Koller at [Lauren.Koller@nerc.net](mailto:Lauren.Koller@nerc.net). An off-line, unofficial copy of the comment form is posted on the project page (see project background below).

### **Project Background**

On January 14, 2008, the NERC Board of Trustees Compliance Committee upheld the Western Electricity Coordinating Council's (WECC's) determination to register the New Harquahala Generating Company (Harquahala) as a Transmission Owner and Transmission Operator. This determination is based on Harquahala's 26-mile 500 kV interconnection facilities that connect the plant with the Hassayampa transmission substation. This decision was upheld by FERC and caused concern for Generator Owners and Generator Operators who owned only transmission "tie-line" facilities used to connect their generating facilities to a transmission substation.

In response to concerns from members of the generator segment regarding this decision, NERC conducted a survey in the Fall of 2008 to define and collect recommendations for resolving stakeholders concerns, and to review and highlight those Transmission Owner and Transmission Operator requirements that should be considered for generic applicability for Generator Owners and Generator Operators for their tie-line facilities. Based on the survey recommendations, NERC formed a group of industry representatives to "Evaluate existing NERC Reliability Standard requirements and develop a recommendation and possible standards authorization request to address gaps in reliability for interconnection facilities of the Generator Owner and expectations for the Generator Operator in operating those facilities. Propose strategies to address or resolve other related issues as appropriate." In November 2009, the group published [report](#) of its conclusions and recommendations.

This project is the result of those recommendations, which include proposed definitions and changes to existing standards to add clarity to Generator Owners and Generator Operators regarding their reliability standard obligations at the interface with the interconnected grid.

Project page: [http://www.nerc.com/filez/standards/Project2010-07\\_GOTO\\_Project.html](http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html)

### **Standards Development Process**

The [Reliability Standards Development Procedure](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

*For more information or assistance,  
please contact Shaun Streeter at [shaun.streeter@nerc.net](mailto:shaun.streeter@nerc.net) or at 609.452.8060.*

- Individual or group. (41 Responses)**
  - Name (26 Responses)**
  - Organization (26 Responses)**
  - Group Name (15 Responses)**
  - Lead Contact (15 Responses)**
  - Question 1 (39 Responses)**
  - Question 1 Comments (41 Responses)**
  - Question 2 (36 Responses)**
  - Question 2 Comments (41 Responses)**
  - Question 3 (32 Responses)**
  - Question 3 Comments (41 Responses)**
  - Question 4 (34 Responses)**
  - Question 4 Comments (41 Responses)**
  - Question 5 (34 Responses)**
  - Question 5 Comments (41 Responses)**
  - Question 6 (35 Responses)**
  - Question 6 Comments (41 Responses)**
  - Question 7 (0 Responses)**
  - Question 7 Time needed to become fully compliant (41 Responses)**
  - Question 7 Comments (41 Responses)**
  - Question 7a (0 Responses)**
  - Question 7a Time needed to become fully compliant (41 Responses)**
  - Question 7a Comments (41 Responses)**
  - Question 7b (0 Responses)**
  - Question 7b Time needed to become fully compliant (41 Responses)**
  - Question 7b Comments (41 Responses)**
  - Question 7c (0 Responses)**
  - Question 7c Time needed to become fully compliant (41 Responses)**
  - Question 7c Comments (41 Responses)**
  - Question 7d (0 Responses)**
  - Question 7d Time needed to become fully compliant (41 Responses)**
  - Question 7d Comments (41 Responses)**
  - Question 7e (0 Responses)**
  - Question 7e Time needed to become fully compliant (41 Responses)**
  - Question 7e Comments (41 Responses)**
  - Question 7f (0 Responses)**
  - Question 7f Time needed to become fully compliant (41 Responses)**
  - Question 7f Comments (41 Responses)**
  - Question 7g (0 Responses)**
  - Question 7g Time needed to become fully compliant (41 Responses)**
  - Question 7g Comments (41 Responses)**
  - Question 8 (0 Responses)**
  - Question 8 Comments (41 Responses)**

Individual
Larry Rodriguez
Entegra Power Group LLC
Yes
But, that action should be reasonable, provide specific detail, and be kept simple so the reliability-related objectives are effectively understood by those operators of the GI Facilities.
Yes
BUT, FAC-003 SHOULD BE APPLIED IN A REASONABLE MANNER. MORE DETAIL SHOULD BE PROVIDED THAN IT WOULD APPLY FOR MORE THAN 2 SPANS. WHAT IF THERE ARE 3 SPANS,

BUT ONLY A QUARTER MILE IN DISTANCE WHICH IS TOTALLY VISIBLE FROM THE GIF. THE SDT SHOULD MAKE SOME REASONABLE CONCESSIONS FOR THESE SITUATIONS, OR ALLOW THE GIF TO DOCUMENT THE SOUND REASONING USED IN NOT IMPLEMENTING FAC-003 TO THE EXTENT REQUIRED BY THE EXISTING STANDARD. A REASONABLE VEGETATION MANAGEMENT PROGRAM SHOULD BE ADEQUATE. MORE DETAIL AND SPECIFICS DESCRIBING WHAT ADEQUATE TRAINING IS FOR PER-002.

Yes
Yes
SEE COMMENTS FOR QUESTION 2.
Yes
SEE COMMENTS FOR QUESTION 2.
No
NO COMMENT
NO COMMENT
1 YEAR
NO COMMENT
NO COMMENT
NO COMMENT
NO COMMENT
NO COMMENT
Individual
Ken Parker
Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners
Yes
Yes
Yes
Yes
Yes
No
18 months
12 months
12 months
12 months
12 months
12 months
8 months

6 months
12 months
FAC-003 - Applicability apply to GIF above 200 kV that exceed two spans should be revised to "less than one-half mile" as span lengths vary considerably. For example we have 3 spans over 1/4 mile. R1. requirement to "keep current, a formal TVMP" should allow latitude for those entities with one-quarter mile of radial connecting transmission, all visible from the office window, to have a less than a formal program, or at least a very SIMPLE program.
Individual
Jack Stamper
Public Utility District #1 of Clark County
Yes
No
Clark Public Utilities believes the scope of the proposed standards actions is too broad.
No
Clark Public Utilities believes the proposed definitions do not provide the necessary amount of guidance and clarity. The proposed definitions and standards revisions are being considered because of the potential impacts of a 26-mile 500 kV Generation Interconnection Facility. The proposed definition for the term "Generation Interconnection Facility" will include the 26-mile interconnection as well as a host of other types of interconnections that should not be considered in this effort. Clark's generator is attached to the transmission grid by slack span (less than 100'™) between the high side of the GSU (owned by the generator) and a circuit breaker (owned and operated by the Transmission Operator) located within the Transmission Operators switchstation. There are no operable components in the slack span. Clark believes the currently proposed standards actions are overly broad. The definitions and applicability of these standards must be narrowed. Clark proposes the following definition for Generator Interconnection Facility. Generator Interconnection Facility Sole-use facility for the purpose of connecting the generating unit(s) to the transmission grid In this regard, the sole-use facility only transmits power associated with the interconnecting generator, whether delivered to the grid or delivered to the generator for station service or auxiliary load, or delivered to meet cogeneration load requirements. Generator Interconnection Facilities shall not include lines that are less than or equal to two spans in length or lines that the host Transmission Operator has agreed to include as part of the transmission system it operates.
No
Many of the new requirements place excessive demands on generators that do not increase system reliability. In EOP-003 Generator Operators are added to the applicability and as a result R7 is a newly applicable requirement to Generator Operators. However, this requirement now implies that Generator Operators are required to engage in the coordination efforts (with the BA and TOP) of automatic underfrequency load shedding. Generators do not have the option of determining what levels of frequency to ride through and what levels of frequency to trip on. Those quantities are defined by the RC and the BA and Generator Operators are required to have generator protection system settings that allow this ride through. Generators should have frequency and voltage ride through requirements that are coordinated with automatic load shedding programs by the RC, BA and/or TOP but should simply be required to comply with these requirements and should not have a role in the coordination. The comments in the GOTO Final report indicate that this addition is required to ensure that a generator frequency trip set point is appropriately included in the currently required coordination between the BA and TOP. Clark believes that generators should not participate in the coordination but simply be required to comply with frequency ride through requirements dictated by the RC, BA and/or TOP. Clark believes that FAC-002 clearly applies to Generator Owners and this standard requires that generator integration facilities address reliability impacts in the interconnected transmission system. Additionally, the proposed change to EOP-003 appears to have nothing to do with the issue at hand (i.e. removal of TOP status to a generator because of a Generator Interconnection Facility). Clark believes it is inappropriate to make EOP-003 applicable to Generator Operators and to imply that a Generator Operator has any participation in coordination of underfrequency load shedding other than to comply with frequency ride through requirements of the RC, BA and/or TOP. Clark agrees that the changes to FAC-003 are appropriate, will lead to increased reliability and do not result in unnecessary reporting or paperwork. The applicability section clearly limits the scope of what Generation Interconnection Facilities would be included in this standard by having a "two span" limit in the length of the facility. This limit appropriately will exclude those generators that have arranged for a Transmission switchstation owned and operated by a Transmission Operator located immediately adjacent to the generator. In IRO-005, R13, the standard proposes to require a Generator Operator to immediately inform the TOP of status changes to SPS. While Clark is not opposed to this change, it is unclear why the issue



at hand (i.e. removal of TOP status to a generator because of a Generator Interconnection Facility) has lead to this addition. The SAR implies that the industry need leading to the SAR is the "registration of Generator Owners and Generator Operators as Transmission Owners and Transmission Operators, based on the facilities that connect the generators to the interconnected grid." IRO-005, R13 does not appear to have any connection to this industry need. In PER-001, Generator Operators are added to the applicability and as a result of the new R2 Generator Operators will be required to demonstrate the authority of operating personnel over Generation Facilities and Generation Interconnection Facilities. This level of authority is unnecessary. Transmission Operators already have this authority (refer to PER-001, R1). Generator Operators are already required to comply with reliability directives issued by RCs, BAs, and TOPs in other reliability standards. The requirement to demonstrate that a generator needs this authority over its generating facility is unnecessary and has no connection with the industry need the SAR is based on. A generator operator has authority over its generator by virtue of its registration as a Generator Operator. The need for further proof that a GOP can operate generation facilities for which it is a registered GOP has not been demonstrated. The requirement to demonstrate that a generator needs authority over a Generation Interconnection Facility is; for the same reason, unnecessary. A generator operator has authority over its generator by virtue of its registration as a Generator Operator for that facility. The need for further proof that a GOP can operate Generation Interconnection Facilities for which it is a registered GOP has not been demonstrated. In PER-002, Generator Operators are added to the applicability and as a result of the new R3 Generator Operators will be required to demonstrate training programs similar to TOP training requirements. Clark is not opposed to training its GOP personnel; however, including the training program within the PER-002 training requirements elevates this training to a level that has not been demonstrated to be necessary in all cases. Currently, this requirement is applicable to a TOP. By removing the TOP classification to certain GO/GOP registered entities that are only a TOP by virtue of Generation Interconnection Facilities, the potential exists that inadequately trained personnel may be directing the operation of a Generation Interconnection Facility. However, as stated earlier, when the Generation Interconnection Facility is short in length and more importantly when this facility has no devices which can be operated (i.e. direct connection between the generator step-up transformer or generator protection circuit breaker (owned or operated by the GOP) and the TOP owned and operated transmission breaker) there is no gap in having adequately trained personnel operating transmission facilities. Clark believes the applicability section should include minimal limits for applicable Generation Interconnection Facilities or that the definition of Generation Interconnection Facilities should be amended such that PER-002 applicability is limited to GOPs that own facilities that are similar in nature to the New Harquahala Generation Interconnection Facilities that have led to this SAR. The proposed changes to TOP-004 are confusing. The proposal does not add GOP in the applicability section but the newly proposed R7 appears to obligate GOPs. The requirement should be revised to obligate a TOP to ensure that a GOP operates within its applicable limits. These limits should have already been established. In FAC-008 Transmission Owners and Generator Owners are required to have a ratings methodology. In FAC-009 TOs and GOs are required to calculate facility ratings. In both of these standards, documentation is to be made available to RCs, TOPs, PAs and TPs that have responsibility. At the very least, the applicability section of a standard should be coordinated with the entities having obligations due to the requirements of a standard.

Yes

Except as discussed in comments 2, 3, and 4, Clark is in agreement with the proposed changes.

No

No time

Clark has no SPS or RAS for which it is responsible.

No Time.

Clark's Generator Operator personnel have responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Generation Facility and the Generation Interconnection Facility, and to implement directives of the Transmission Operator and Balancing Authority.

Twelve months.

Clark's generating operating personnel regularly engage in training however, to implement a Training Program as rigorous as the TOP Training Program will take some time to complete.

No Time.

Clark believes the operation of its generator is already under the direction of its TOP and that coordination has already occurred since the TOP has included the operation of Clark's generator in its TOP-002 Normal Operations Plan.

No time.

Clark believes that existing standards already grant the TOP decision-making authority for the Generator Interconnection Operational Interface.

No time.

Clark's Generation Interconnection Facility status is already provided to the TOP in real time over the TOP's SCADA system.

No time.

The Generation Interconnection Facilities of Clark have ratings that exceed the maximum generating capability of the interconnected generation facility.

No time.

Clark has experienced no operating conditions where it had to disconnect the Generation Interconnection Facility immediately due to an overload or other abnormal condition that threatened equipment or personnel safety.

Individual

Daniel E. Kujala

Detroit Edison Company

No

Vegetation Inspection change to include any BES component Transmission Line or Generator Interconnection Facility Right-of-Way or any other BES component to document vegetation conditions .

Yes

Yes

Yes

No

Individual

Mark Bennett

Competitive Power Ventures, Inc.

Yes

In fact, the technical analysis in the Ad Hoc Group's Report provides a valuable and useful understanding of the specific nature and extent of reliability issues associated with generator interconnection facilities. Up to now, the need for generator TO/TOP registrations has not been supported by a clear and technically sound rationale. The Report's conclusion, based upon its comprehensive and thorough review, that there is no need for generators to be registered as TO/TOPs to address the specific reliability issues is especially significant.

Yes

Yes

Yes

No

Every effort should be made to precisely describe requirements that directly correspond to, and address, the reliability issues framed by the GO/TO Ad Hoc Group. Particularly, "interconnection facilities" should be defined to account for and exclude various transmission configurations on the generator side of the interconnection point that do not create network power flows or otherwise operate as bona fide transmission systems.

Group

SERC Planning Standards Subcommittee

Philip R. Kleckley

Yes

Yes

No

We suggest 3 alternate modified definitions: Right-of-Way (ROW) A corridor of land on which a Transmission Line or Generator Interconnection Facility may be located. The owner of the Transmission Line or Generator Interconnection Facility may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines. Vegetation Inspection The systematic examination of a Right-of-Way to document vegetation conditions. The main reason for the change in definition for ROW was the proposed use of the non-capitalized term "electric line". Since the use of that phrase sometimes means distribution lines as well as transmission, we suggest staying with the capitalized NERC terms for better clarity. Generator Operator The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services. The Generator Operator may also operate the Generator Interconnection Facility. The main reason for the change in the definition for Generator Operator was that the 2nd sentence in the proposed definition was a requirement and not a true definition. The other change was to allow for the case where the Generator Operator was not the operator of the Generator Interconnection Facility.

Yes

Yes

No

12 months

12 months

12 months

12 months



The items in Question #7 illustrate the need for a written Agreement or Procedure between the GO, GOP, TO and TOP on how to comply with these new, and modified, Requirements. An Agreement or Procedure would provide the certainty of:  Assignable and measurable responsibilities,  Mutual agreement on specific actions, and  Implementation deadlines. Without such an Agreement or Procedure, there will be no auditable commitment to defined specific actions, predetermined responsibilities and closure of the reliability gap in total.

Group

Luminant

Rick Terrill

No

In general, Luminant agrees there is a need to address generation facilities with extended connections to the transmission system. However, Luminant does not agree there is a reliability need for the proposed standards action as it relates to generators connected in close proximity to the grid where the connection typically consists of a bus or short wires connection from the high side of a generator step up transformer to the generator breaker.

No

: Luminant believes the scope of the standards action significantly exceeds the reliability need. The scope should only extend to Generation Interconnection Facilities of greater than one-half (½) mile in length from the property boundary of the generation plant. This standards action should only be applied where there is a demonstrated reliability benefit. For the bulk of the Generator Owners, the proposal creates excessive documentation and paperwork, and increases compliance risk with no reliability benefit to the Bulk Electric System (BES).

No

No, for the bulk of the Generator Owners whose Generation Interconnection Facilities (GIF) are connected in close proximity (i.e., one-half mile or less) to the BES, the requirements will only add additional unduly burdensome documentation, paperwork and compliance risk, with no reliability benefit

No

The following comments are specific to each standard CIP-002  This standard is currently under revision and any change should be addressed by the Cyber Security Standards Revision Team. EOP-003  Application of this reliability standard to a GOP is incorrect. The Generator Operator has no direct responsibility for load shedding. Only the TOP and BA have load shedding responsibility. EOP-004  The inclusion of GIF in this reliability standard is redundant as the GOP has responsibility for all of its facilities, including any generators. . Since generation units are not independently identified with a particular GOP, the GIF does not need to be independently identified. Also, there is a NERC project currently underway to revise this standard (Project 2009-01). FAC-003  Luminant agrees this standard should apply in those instances when the generator is connected to the BES through its GIF over a substantial distance. However, the applicability of this standard to a GIF needs to specify a distance (such as one-half (½) mile from the plant property boundary) not a number of spans since the spacing between spans can vary from extensively. Defining the applicability of this standard in terms of a number of spans will create inconsistency in the application of the requirements. IRO-005  New requirement R13 presumes that a Special Protection System (SPS) is the sole responsibility of a GOP, which, in most cases, it is not. Most SPS are the responsibility of the TO, not the GOP. This requirement does not define which SPS is being monitored. A requirement of this nature should define an SPS on the GIF. PER-001  The addition of a requirement applicable to GOP in this standard goes well beyond the scope of this projects purpose. A NERC Standards Drafting

Team, under Project 2006-01, did not add any GOP requirements to the PER standards. This proposed GOP requirement is redundant. Current NERC Reliability Standard TOP-001, R3 requires Generator Operators to follow reliability directives, as does IRO-001, R8. This proposed requirement should be deleted. It adds paperwork, documentation and compliance risk with no reliability benefit. The PER-001 standards were intended for overall grid management, not the operation of a power plant. PER-002 “ The recent NERC Standards Drafting Team, under Project 2006-01, specifically declined to make this standard applicable to GOP. In addition, the 2006-01 project is retiring this standard with the adoption of the revised PER-005. PRC-001 “ The inclusion of Generator Interconnection Facility is redundant. However, there is a current NERC Drafting team revising PRC-001 and this issue should be referred to that team. PRC-005 “ Any revisions to PRC-005 should be referred to the current PRC-005 drafting team. TOP-001 “ Draft Requirements R9 and R10 are extremely broad. These should only apply to narrowly defined GIFs such as long span connections or GIFs with transmission load flowing through the GIF. Care should be taken in this requirement not to duplicate requirements such as coordination of outage planning. The requirements should be specific, and not fill in the blank for the TOP or region. TOP-004 “ Draft Requirement R7 is redundant to requirements in other standards and is not needed. IRO-005-2, R13, and IRO-005-3, R10, require the GOP to operate the BES to its most limiting factor, which is, by definition, implicitly within its facility ratings. TOP-008 “ Does draft requirement R5 fit in this standard that addresses IROL and SOL? This requirement should only apply to the same long connection GIF facilities identified in TOP-003.

No

18 months

18 months

24 months

18 months

18 months

18 months

18 months

36 months

Individual

Amir Hammad

Constellation Power Source Generation Inc.

Yes

Yes - Defining the compliance responsibility to align more accurately with operational reality is important in managing reliability. However, the SDT must also consider those entities that enter into a Joint Registration Organization (“JRO”) for certain GOP reliability standards. This registration exception applies to market entities, where there has been a JRO created that delineates specific joint responsibilities, with respect to the GOP reliability standards. It is incumbent on both parties to comply with their agreed upon respective responsibility.

No

Please see the comments for Question #4

No

The term “point of interconnection” must be used in the glossary definitions of a “Generator Interconnection Facility” and “Generator Interconnection Operational Interface.” It is a common industry term that is widely understood, and is even being used in the revision to FAC-008. Using the term “point of interconnection” would further clarify the new glossary definitions. Here are the proposed changes: Generator Interconnection Facility (NEW) Sole-use facility for the purpose of connecting the generating unit(s) to the transmission grid. In this regard, the sole-use facility only transmits power associated with the interconnecting generator, whether delivered to the grid or delivered to the generator for station service or auxiliary load, or delivered to meet cogeneration load requirements. The Generator Interconnection Facility is physically defined as the facility and its encompassing equipment beginning at the low side of the Generator Step Up to the point of interconnection. Generators

connected to the same interconnection facility with different Generator Operators must coordinate operations. Generator Interconnection Operational Interface (NEW) Location at which operating responsibility for the Generator Interconnection Facility changes between the Transmission Operator and the Generator Operator. This location is known as the point of interconnection.

Yes

Constellation agrees with the proposed new requirements in principal. However, further clarity is needed in the requirements so that there isn't any added confusion. Either an implementation plan or a "frequently asked questions" document would be recommended.

No

Constellation agrees with the proposed changes for BAL-5, EOP-1, EOP-4, EOP-8, FAC-1, FAC-8, FAC-9, IRO-5, MOD-10, MOD-12, PER-1, PRC-1, PRC-5, TOP-1, TOP-2, TOP-3, VAR-1, and VAR-2. Furthermore, the changes made to CIP-2 are especially valuable in that the clarity it brings with the added terminology would assist in identifying individual assets. Constellation does not agree with (or has comments for) the proposed changes to: "EOP-3" GOs/GOPs should not be included in this standard "FAC-3" Constellation agrees in principal with this change, but further work is needed in regards to which GOs fall into this category. The wording may be changed to "two or more spans exceeding 1/2 mile in total length," but further discussions is needed on this topic. "PER-2" Constellation agrees in principal with this change, but believes that this requirement should be combined into PRC-001 R1, and eliminate the redundancy. "PRC-5" Testing of the Protection System of the Generator Interconnection Facility is not always the sole responsibility of the GO. Some verbiage attesting to that is needed. Otherwise, it is wise to include the Generator Interconnection Facility into this standard so that no gap may exist in the testing of a Protection System that may impact the BES.

No

1 year

2 years

Time is needed for training and terminology to percolate throughout the Generation Facility and that it be ingrained with the Operators.

2 years

Time is needed to implement a training plan and revise it based on feedback from those being trained.

1 year

1 year

1 year

1 year

1 year

Constellation would like to thank the Ad-Hoc group for the excellent work they did in creating the GOTO Final Report. In particular, here are a few excerpts that Constellation agrees with, and would like the future SDT to consider: "The Generator Owner or Generator Operator that owns and/or operates a Generator Interconnection Facility, that is, a sole-use facility that interconnects the generator to the grid, should not be registered as a Transmission Owner or Transmission Operator by virtue of owning or operating its Generator Interconnection Facility. A Generator Interconnection Facility is considered as though part of the generating facility specifically for purposes of applying Reliability Standards to a Generator Owner or Generator Operator. After review of the existing Transmission Operator requirements that are not currently applicable to Generator Operators, no existing Transmission Operator requirements should apply to Generator Operators as a result of the Generator Interconnection Facility.

Individual

Alisha Anker

Prairie Power, Inc.

Yes

No

PPI believes the group has extended the scope too broadly from its initial intent as described in comments below.

No
PPI agrees with the first and existing sentence of the Generator Operator definition. However, the first part of the second sentence regarding operating the Generator Interconnection Facility is redundant with the first sentence. The second portion of the second sentence regarding coordinating with the Transmission Operator has been established already in TOP-001 R7.1 and TOP-003 R1.1 for the purpose of this project.
No
PPI considers the phrase "for SPS relay or control equipment under its control" to be confusing and ambiguous in the new requirement IRO-005 R13. We suggest deletion of this phrase maintains the intent of the requirement and removes the unclear reference to the subject associated with the word "its". PPI questions why the sub-elements of new requirement TOP-001 R9 are stipulated in bullet item format rather than sub-requirement format. PPI agrees with the first portion of new requirement PER-001 R2. Regarding the second portion of new PER-001 R2, the Generator Operator is already required to comply with Reliability Coordinator directives as established in IRO-001 R8 and TOP-001 R3, and further the Generator Operator is already required to comply with Transmission Operator directives also as established in TOP-001 R3. PPI does not see any benefit in reiterating the Generator Operator responsibility and authority to follow directives in this new requirement. PPI would suggest stipulating the Generator Operator be responsible for following directives of the Balancing Authority in a separate Requirement or sub-requirement, and not lumped into this new requirement.
No
PPI does not agree with the modification to EOP-003 R7. The Generator Operator does not have load to be shed, therefore none to be coordinated. If the drafting team is intending to require the Generator Operator to coordinate the underfrequency relay settings on their resources with load shedding plans established by the Transmission Operator and Balancing Authority, this is an appropriate requirement. The modification, though, does not accomplish this. PPI questions why the sustained line outages reported quarterly to the RRO pursuant to FAC-003 R3 by the Generator Owner, as modified, are not reported to NERC in Requirement 4 of the same Standard.
No
12 months following Regulatory Approval
12 months following Regulatory Approval
24 months following Regulatory Approval
24 months following Regulatory Approval
12 months following Regulatory Approval
12 months following Regulatory Approval
12 months following Regulatory Approval
12 months following Regulatory Approval
PPI contends this SAR and associated requirement additions and revisions go well beyond the recommendations from the Group needed to resolve the barrier issue between Transmission Operator and Generator Operator. The FAC-003 standard revision, so that vegetation management can be enforced for transmission lines which interconnect generators to transmission, is really all that is necessary. All these other changes just add confusion to already overlapped requirements.
Individual
Michelle D'Antuono
Ingleside Cogeneration, LP
Yes
Ingleside Cogeneration, LP believes that the effort by the Ad Hoc Group for Generator Requirements at the Transmission Interface has generally succeeded in developing criteria clarifying the ownership and operational responsibilities of registered generation and transmission entities at their point of interface. This is an important body of work which needs to result in an end to the forced registration of Generator Owners/Operators (GO/GOP) as Transmission Owner/Operators (TO/TOP) by Regional Entities.









(possibly because MOD-013 is not FERC approved). "PER-001" The Purpose statement is not in alignment with the additional GOP applicability.

Individual

Jon Kapitz

Xcel Energy

Yes

Should the definition of Generator Interface Facility indicate that no BES (or any) loads be tapped between the generator and the GIF operational interface?

There are many other standards development projects underway that are modifying the same standard. It is unclear as to how the changes will be coordinated amongst the many teams.

Group

ISO RTO Council Standards Review Committee

Ben Li

Yes

No

Please see our comments under Q8.

No

(1) Generator Operator: We agree with the first sentence of the definition for Generator Operator, but do not agree with the need for the second sentence. The first sentence already states inclusion of Generator Interconnection Facility. The first part of the second is simply a repeat of this change. The latter part of the second sentence is a requirement that should be stipulated in an appropriate standard. We suggest to strike out the second sentence.

No

Please see our comments under Q5 where we comment on both the additions and modifications to the standards.

No

While we generally agree with the proposed wording change, we have a number of comments the first of which is a timing decision issue. (1) We realize that the SDT needs to make changes to "approved standards" but there are a number of standards involved in this project whose newer versions have either received the BoT approval, or about to be adopted by the BoT or at the stage of being finalized or balloted. To make changes to the soon to be outdated versions is confusing and will require a subsequent change when FERC approves the standards. We therefore suggest the SDT to coordinate their changes with the other drafting teams that are working on the newer versions already or soon to be adopted by the BoT and those that are being balloted. Alternatively, the SDT may want to post the changes to those FERC approved standards only, and defer actions on those that have not been approved by FERC and those that are being revised/balloted until FERC approves them. (2) EOP-001: R7.3 has been changed to add the term "outages", including outages to the Generator Interconnection Facility, to maximize a



EPSA members, through active participation in many NERC activities including the team that prepared the report and the attached SAR, are strong advocates of mandatory standards to protect reliability of the Grid. We also strongly agree that there is a need for greater clarity of the responsibilities of Generator Owner/Operators and Transmission Owner/Operators at the Generator Interconnection Interface and thus concur with the direction of this SAR that this should be achieved without the need for Generator Owner/Operators to be included in the registry as Transmission Owner/Operators.

Yes

Yes

In particular we support the revised definition of the Generator Interconnection Facility, which has appropriately incorporated our comments from the draft of the Team's report

No

We are supportive of most of the new requirements being suggested with the following two exceptions: IRO-005 R13 which states: R13. The Generator Operator shall immediately inform the Transmission Operator of the status of the Special Protection System, including any degradation or potential failure to operate as expected for SPS relay or control equipment under its control. We believe that this proposed additional requirement is redundant as it is already covered by the requirements of PRC-001-1 AND TOP-001 R10 which states: The Transmission Operator shall have decision-making authority over operation of the Generator Interconnection Operational Interface at all times in order to preserve Interconnection reliability. We would amend the proposed R10 as follows: The Transmission Operator shall have decision-making authority over operation of the Generator Interconnection Operational Interface at all times in order to preserve interconnection reliability, unless by exercising that authority such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.

No

Comments: see my note re FAC-003 We are supportive of the modified requirements being suggested with the following exception: FAC-003: We offer the following suggested changes for greater clarity. 4. Applicability: Replace the proposed sections 4.4 and 4.5 with the following: 4.4. Generator Owner that owns a Generator Interconnection Facility above 200 kV that exceed two spans from the generator property line or are below 200 kV and deemed critical to the reliability of the electric system by the Regional Entity (subject to the two-span criteria.) Furthermore, the Standard Drafting Team should insure that in drafting the requirements and subsequent sections of the standards, it is clear that the use of the words "Generator Owner" refers only to the subset of Generator Owners as specified by section 4.4, not to all Generator Owners included in the NERC Registry.

No

1 year

2 years

2 years

1 year

1 year

1 year

1 year

1 year

We commend the work of the team that produced the report and this SAR and suggest that the Standard Drafting Team give due deference to the report with the modifications that we have suggested in questions 4 and 5 above. In addition, EPSA would highlight the following conclusions that follow from the report: "The Generator Owner or Generator Operator that owns and/or operates a Generator Interconnection Facility, that is, a sole-use facility that interconnects the generator to the grid, should not be registered as a Transmission Owner or



No
E.ON U.S. has already determined a Division of Responsibilities between the GO/TO and therefore does not see the need for auditable reliability standards to be added between the GO/TO. Also, it is not necessary to include the phrase "including the Generator Interconnection Facility" in all the applicable requirements. Since the term Generator Interconnection Facility is proposed to be included in the Glossary definitions for Generator Operator, then it would be redundant to also add the phrase throughout the applicable standards.
No
E.ON U.S. has already determined a Division of Responsibilities between the GO/TO and therefore does not see the need for auditable reliability standards to be added between the GO/TO.
No
A training program for this would need to be created, procedures approved, implemented, and instituted at all power plants for all shifts. E.ON U.S. recommends that the addition of PER-002 R3 be coordinated with the existing standard PRC-001 R1, to eliminate redundancy.
Appears redundant with point e) below. There are already generator-outage reporting protocols in place. This would be an unnecessary addition to existing processes.
In case of overload, the E.ON U.S. GOP has an overload current relay that already removes a generating unit from the grid immediately. Moreover, it is expected that in most cases an Interconnection Agreement between the generator and TO that it connects with already contains language supportive of this.
This SAR should only apply to those separate entity GOPs that already adhere to an OATT. Those GOPs should be required to register additionally as a TO/TOP. This should not apply to a GOP within a Corporation that includes TO/TOP that adhere to an OATT, and have already defined an internal division of responsibilities for the Transmission Interface between the GOP and TOP.
Individual
James Sharpe
South Carolina Electric and Gas
Yes
Yes
Yes
Yes
Yes
No
18 months
12 months
12 months





Transmission Owner/Operators.
Yes
Yes
No
TOP-001 R10 should be amended such that the proposed R10 reads as follows: The Transmission Operator shall have decision-making authority over operation of the Generator Interconnection Operational Interface at all times in order to preserve interconnection reliability, unless by exercising that authority such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.
No
We are supportive of the modified requirements being suggested with the following exception related to the suggested changes on FAC-003 for which we offer the following modification for greater clarity: 4. Applicability: Replace the proposed sections 4.4 and 4.5 with the following: 4.4. Generator Owner that owns a Generator Interconnection Facility above 200 kV that exceed two spans from the generator property line or are below 200 kV and deemed critical to the reliability of the electric system by the Regional Entity (subject to the two-span criteria.) Furthermore, the Standard Drafting Team should insure that in drafting the requirements and subsequent sections of the standards, it is clear that the use of the words "Generator Owner" refers only to the subset of Generator Owners as specified by section 4.4, not to all Generator Owners included in the NERC Registry.
No
1 year
2 years
2 years
1 year
1 year
1 year
1 year
1 year
We commend the work of the team that produced the report and this SAR and suggest that the Standard Drafting Team give due deference to the report with the modifications that we have suggested in questions 4 and 5 above. In addition, we would highlight the following conclusions that follow from the report: " The Generator Owner or Generator Operator that owns and/or operates a Generator Interconnection Facility, that is, a sole-use facility that interconnects the generator to the grid, should not be registered as a Transmission Owner or Transmission Operator by virtue of owning or operating its Generator Interconnection Facility " A Generator Interconnection Facility is considered as though part of the generating facility specifically for purposes of applying Reliability Standards to a Generator Owner or Generator Operator " After review of the existing Transmission Operator requirements that are not currently applicable to Generator Operators, no existing Transmission Operator requirements should apply to Generator Operators as a result of the Generator Interconnection Facility
Individual
Kevin Gillespie
El Dorado Energy LLC
Yes
Yes
Yes



NRECA is concerned with the decision to use revisions to the latest versions of the following standards that were included in red-line format in this SAR: BAL-005 CIP-002 EOP-001, -003, -004, -008 FAC-001, -003, -008, -009 IRO-005 MOD-010, -012 PER-001, -002 PRC-001, -004, -005 TOP-001, -002, -003, -004, -008 VAR-001, -002 The use of these versions of the standards, many of which have been revised, approved by the NERC Board of Trustees and filed with FERC emphasizes the flaw in a regulatory approval process that is not uniform throughout North America. Not all registered entities are FERC jurisdictional, therefore, are already required to comply with Reliability Standards upon NERC Board of Trustees approval. Of the standards that are included in this SAR, three projects not including interpretations have been retired, modified, or new standards created that are now complied with by some registered entities. The projects include; Project 2006-01 System Personnel Training PER-002, PER-004, and PER-005, Pre-2006 Operate Within Interconnection Reliability Operating Limits IRO-007 through IRO-010 and Project 2008-06 Cyber Security Order 706 CIP-002 through CIP-009. In addition, it is difficult to determine whether there is any coordination between the activities of this SAR drafting team and those of the many existing drafting teams that are also revising standards. NRECA understands the dilemma of how to revise standards in a regulatory environment that has no defined time-line guidelines for approval of standards upon filing with FERC, but reminds NERC, the Standards Committee and drafting teams that the process must address the varying regulatory approval processes in North America.

Individual

Greg Rowland

Duke Energy

Yes

Yes

No

The definitions of Generator Owner and Generator Operator should not be revised, because every Generator Owner and Generator Operator may not own and operate a Generator Interconnection Facility, as the revised definitions imply. The revised definition of Generator Operator also adds a coordination requirement which is more properly included in the requirements of a standard. While we are sensitive to the fact that this SAR is attempting to close a reliability gap, we believe that the definition of Generator Interconnection Facility is too broad. The Standard Drafting Team should consider limiting it to the voltages defined for the Bulk Electric System, and other facilities as deemed critical by the Regional Entity. Also, how does the Regional Entity deem a facility critical? The Right-of-Way (ROW) definition should spell out TO and GO. Suggested rewording: A corridor of land on which electric lines may be located. The Transmission Owner or Generator Owner which owns the lines may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain the lines.

No

See detailed comments under Question 5 below.

No

General Comment The Standards Drafting Team (SDT) will need to make sure that Measures are developed or modified to correspond to new or revised requirements of the standards. Process Question Will the SDT fold these standards revisions into other projects, or will new versions be created as part of this project? FAC-003-1 Applicability sections 4.4 and 4.5 should be combined to make it clear that the standard only applies to the Generator Owner's GIF. Does the 2-span limit mean that there are three towers? What criteria will the Regional Entity use to deem a GIF critical? The language about the generator property line is confusing how does it compare to the Right-of-Way (ROW) definition? In some cases the TO may own the ROW, while the GO owns the GIF. FAC-008-1 Requirement R1 raises a question regarding whether a GIF can be jointly owned by a TO and a GO. If a TO is an owner, then the GIF is not a GIF but a transmission facility, right? FAC-009-1 We don't think revisions are needed to R1 and R2, since the term Facilities already implicitly includes GIF. If you don't agree, then perhaps a more straightforward approach would be to revise the definition of Facility to explicitly include the GIF. IRO-005-2 We think that you don't need to specifically add the GIF to R9 because it would have to already be included in the requirement as part of any generation outage coordination. Under R13 we would change the Special Protection System to any

Special Protection System. We also note that this new R13 propagates the poor language of R12 (i.e., how does anyone define "potential failure to operate"?). PER-001-0 Applicability section 4.3 should be expanded to make it clear that Requirement R2 only applies to the Generator Operator with respect to the GIF, and R2 should be likewise revised. The GOP is already obligated under TOP-001-1 Requirement R3 to comply with RC and TOP directives unless such actions would violate safety, equipment, regulatory or statutory requirements. Suggested rewording of Applicability section 4.3 : "Generator Operators This standard shall apply to Generator Operators who own a Generator Interconnection Facility." Suggested rewording of Requirement R2 : "For Generation Facility Interconnection equipment under their direct control, each Generator Operator shall provide operating personnel with the responsibility and authority to implement real-time actions and to follow reliability directives of Reliability Authorities, Transmission Operators and Balancing Authorities, to ensure the stable and reliable operation of the Generation Interconnection Facility." PER-002-0 - Applicability section 4.3 should be expanded to make it clear that Requirement R2 only applies to the Generator Operator with respect to the GIF. Suggested rewording of Applicability section 4.3 : "Generator Operators This standard shall apply to Generator Operators who own a Generator Interconnection Facility." PER-001-1 Changes to PRC-001-1 should probably not be made right now, because it is already a vague standard, and was the subject of an Interpretation (Project 2009-30) which was voted down in February. TOP-003-0 Requirement R1 and its sub-requirements are poorly written. We suggest folding R1.3 into R1 with this suggested rewording: "Generator Operators and Transmission Operators shall provide planned outage information by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection, as follows : TOP-004-2 We question whether Requirement R7 is appropriate, since by definition the GIF is not part of the transmission system network and does not fit with the Purpose statement of this standard. If R7 is retained, then you need to add Generator Operator to the Applicability section. TOP-008-1 Need to add GOPs to the Purpose statement.

No
However the SDT should perform a complete review.
Approximately 3 months.
Depends upon measures and data requirements, but would probably be a short period of time.
Approximately 24 months.
Multiple shifts and multiple facilities will require time to get training developed and delivered.
Approximately 24 months.
Multiple shifts and multiple facilities will require time to get training developed and delivered.
Approximately 3 months.
Depends upon measures and data requirements, but should be a short period of time.
Approximately 3 months
Depends upon measures and data requirements, but should be a short period of time.
Approximately 3 months
Depends upon measures and data requirements, but should be a short period of time.
Approximately 3 months.
Depends upon measures and data requirements, but should be a short period of time.
Approximately 3 months.
Depends upon measures and data requirements, but should be a short period of time.
Individual
James H. Sorrels, Jr.
American Electric Power
Yes
No
No
It is unclear if the Generator Interconnection Facility definition only includes facilities at 100 kV or greater or those deemed critical to the Bulk Electric System by the Regional Entity.
No
AEP believes that the only new requirement that should be addressed is in reference to FAC-003. AEP does not see benefit in expanding the scope of EOP-003, PER-001, and PER-002. With respect to TOP-004, AEP does not feel the added requirement is necessary as the Generator Interconnection Facility should be adequately sized to handle the output of the generator. The added requirement in TOP-008 for notification is redundant with other obligations for the GOP to notify other entities, such as in COM-002 and TOP-003.

Yes
AEP feels that a majority of the standards that were modified add clarity. We reserve the right to comment when the Standard Drafting Team posts the draft Standard(s).
No
At this point in time, AEP cannot identify any other TO/TOP requirements that should be considered.
AEP believes that this requirement is not needed and should be out of the scope for this SAR.
AEP believes that this requirement is not needed and should be out of the scope for this SAR.
AEP does not believe that the added requirement is necessary as the Generator Interconnection Facility should be adequately sized to handle the output of the generator.
Overall, AEP supports the concept of this SAR, but we question the number of new requirements that are being brought in scope. Some of the requirements added appear to encourage this SAR to reach farther than the scope of addressing the Generator Interconnection Facilities.
Group
Midwest ISO Standards Collaborators
Jason L. Marshall
Yes
Yes
No
We agree with the first sentence of the definition of Generator Operator. However, the first part of the second sentence regarding operating the Generator Interconnection Facility is redundant with the first sentence. The second portion of the second sentence regarding coordinating with the Transmission Operator is a requirement and already established in requirement X.
No
The requirement additions to the TOP standards parallel requirements that the Real-Time Operations standards drafting team has already proposed for removal. This project needs to be coordinated with the Real-Time Operations project.
No
We do not agree with the modification to EOP-003 R7. The Generator Operator does not have load shed to coordinate. We believe the drafting team is intending to require the Generator Operator to coordinate underfrequency relay settings on their generators with the BA and TOP load shedding plans. We agree this is appropriate but the modification does not accomplish this. EOP-004 R2 seems to be modified unnecessarily. System and facilities are already included in the requirement and, thus, would include the Generator Interconnection Facility. We do not agree adding Generator Interconnection Operational Interface to R1.3 in EOP-008. The sub-requirement already requires the contingency plan to consider generation control which would require consideration of the Generator Interconnection Operational Interface. Furthermore, there is a lack of coordination with the project to update this standard. A newer, significantly modified version of this standard has already been through an initial ballot period. IRO-005 R9 modifications are not needed. The requirement already requires an RC to coordinate pending generation outages. This would have to include any outage such as the Generator Interconnection Facility. Many of the changes to the TOP standard are modifying requirements that the Real-Time Operations standards drafting team has already proposed for removal. This project needs to be coordinated with the Real-Time Operations project. VAR-001 R8 modifications are not necessary because the TOP is already required to operate reactive generation scheduling. They can't do this without considering the Generator Interconnection Facility.





TOP's responsibility to provide a directive of this nature since the TOP would have a greater perspective/visibility than the GO/GOP of the system operating conditions in real time?

No

We agree with most all of the modified requirements with one exception: For FAC-003, regarding the "two-span criteria" or "about 0.5 miles" test for generator applicability, we would like the ad hoc team to consider providing more direction or greater specificity that makes a GIF of two or less spans to become exempt, while one of greater than two spans (0.5 mile) but less than 5 spans (0.8 miles) to suddenly become subject to the FAC-003 standard requirements. The "generator's line-of sight" rule as described in response to item #3 in the Final Report in our opinion should be clearly specified in the FAC-003 proposed standard change at a minimum to avoid mis-interpretations. Also, regarding item #10 issue in the report, we would like the ad hoc team to consider proposing a 4th proposal which would be a hybrid between Proposal 2 and Proposal 3 as reported within the Final Report which would provide a "bright-line test" as to what generators are exempt or not to the FAC-003 standard, rather than solely relying on Proposal 2 which relies on the physical attributes of the GIF in ruling out generators subject to FAC-003. If the GIF is 3-4 spans or 0.53 miles in length, but still within the "line of sight" of the GOP, then allow the GOP working with the RE and TOP to rule out smaller generators that are immaterial to the reliability of the grid.

No

12 months

12 months

12 months

12 months

12 months

12 months

12 months

12 months

NCEMC is concerned with the decision to use "revisions to the latest versions of the following standards" that were included in red-line format in this SAR: BAL-005 CIP-002 EOP-001, -003, -004, -008 FAC-001, -003, -008, -009 IRO-005 MOD-010, -012 PER-001, -002 PRC-001, -004, -005 TOP-001, -002, -003, -004, -008 VAR-001, -002 The use of these versions of the standards, many of which have been revised, approved by the NERC Board of Trustees and filed with FERC emphasizes the flaw in a regulatory approval process that is not uniform throughout North America. Not all registered entities are FERC jurisdictional, therefore, are already required to comply with Reliability Standards upon NERC Board of Trustees approval. Of the standards that are included in this SAR, three projects not including interpretations have been retired, modified, or new standards created that are now complied with by some registered entities. The projects include; Project 2006-01 System Personnel Training PER-002, PER-004, and PER-005, Pre-2006 Operate Within Interconnection Reliability Operating Limits IRO-007 through IRO-010 and Project 2008-06 Cyber Security Order 706 CIP-002 through CIP-009. In addition, it is difficult to determine whether there is any coordination between the activities of this SAR drafting team and those of the many existing drafting teams that are also revising standards. NCEMC understands the dilemma of how to revise standards in a regulatory environment that has no defined time-line guidelines for approval of standards upon filing with FERC, but reminds NERC, the Standards Committee and drafting teams that the process must address the varying regulatory approval processes in North America.

Group

Florida Municipal Power Agency

Frank Gaffney

Yes

No

FAC-003 should not be applicable to Generator Owners / Operators. The intent of all of the



standards is to avoid an Adverse Reliability Impact, or as the FPA Section 215(a)(4) defines a "reliable operations" as: "operating the elements of the bulk-power system within equipment and electric system thermal, voltage and stability limits so that instability, uncontrolled separation, or cascading failures of such systems will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements." Radial Facilities serving only generating plants when tripped will not threaten an Adverse Reliability Impact or we would be hard pressed to run that generation in the first place. FMPA believes the intent of the standard is to prevent a cascading event where, if a line trips, another line loads heavily increasing the sag of that line, which may sag into un-cleared vegetation, causing the second line to trip, which may in turn cause heavily loading on a third line, etc. If a line trips in the transmission network, radial Facilities from generating plants will not have their loading changed much at all (since they are radial) and will not participate in this sort of "thermal" cascading event. Hence, there is no cause to regulate vegetation management of radial Facilities to generating plants since the system is always planned and operated to that potential contingency anyway and there is no danger of an Adverse Reliability Impact. Regulating vegetation management on radial Facilities is beyond the scope of the Federal Power Act Section 215. Generator Owners / Operators are still incented to perform adequate vegetation management without the need for regulation because any outage of the plant results in lost opportunity costs to the plant.

Yes

Yes

No

The modification of EOP-003-1, R7 is inconsistent with the requirement. The original requirement requires the BA and TOP to coordinate with others (presumably DPs, TOs and GOPs) in their area for various automatic action (e.g., UFLS, automatic tripping of cap banks, and frequency capabilities of generators for instance). The GOP has no "area" to coordinate and no one within its area to coordinate with. So, it is the BA and TOP that coordinate within their area, not the entities embedded within the BA or TOP area. Otherwise, we ought to add at a minimum DPs, LSEs, and TOs to the list. The modifications to EOP-004-1 R2; FAC-001-0 R1.1; FAC-008-1; FAC-009-1; MOD-010, MOD-012, PRC-001, PRC-004; PRC-005; TOP-001-1 R7; TOP-002 R3 and R18; TOP-003 R1 and R1.1; and VAR-002 R3.2 are redundant with no need to specifically call out the Generator Interconnection Facility. The interconnection facilities are facilities and already included in the term "on its system or facilities" and "generating facilities", etc. And, the Generator Owner and Operator are already responsible for their interconnection facilities in the definition of those Entities. Specifically calling out the interconnection facilities calls into question why other facilities are not specifically called out. As discussed in the response to #2 above, addition of the Generator Owner to FAC-003 over-steps Federal Power Act Section 215 since radial transmission lines to generating plants will not participate in a cascading outage since the loading of radial facilities to power plants will not change significantly with outages on the interconnected system.

No

The amount of time it takes to compile documentation to fulfill the data retention requirements of the requirement

For most of these new requirements, the Entities are most likely fulfilling the requirements, but, may be missing the documentation to prove that they are doing so. So, to be auditably (a "fully") compliant, the Entities will need the amount of time it takes to build up sufficient evidence of compliance. This may only be a month to develop documentation, to a longer period of time to prove periodicity (e.g., a PRC-005 type of requirement "not PRC-005 itself" but a requirement that may need to be done periodically such as training to show that it is done periodically).

See above

See above

See above

See above

See above

See above

See above

See above

See above

See above

See above

See above

See above
See above
See above
Group
Bonneville Power Administration
Denise Koehn
Yes
Yes
Yes
Yes
However, believe there is a problem with #8 referring to TOP-008. The solution to the generator facility line overload may be a transmission system problem so the Generator should not disconnect unless the TOP directs it to do so (confer unless a safety issue). Also, TOP-001 needs careful work. The transmission system doesn't want environmental issues turning off generators during emergency or critical transmission conditions.
Yes
No
1 year, if agreements need to be renegotiated.
6 months
2-3 years, depending on the extent of equipment involved and size of facility.
1 year, if agreements need to be renegotiated.
1 year, if agreements need to be renegotiated.
6 months.
0 months.
1 year, if agreements need to be renegotiated.
Individual
Dan Rochester
Independent Electricity System Operator
Yes
Yes
No
(1) Generator Operator: We agree with the first sentence of the definition for Generator Operator, but do not agree with the need for the second sentence. The first sentence already states inclusion of Generator Interconnection Facility. The first part of the second is simply a repeat of this change. The latter part of the second sentence is a requirement that should be stipulated in an appropriate standard. We suggest to strike out the second sentence. (2) Generator Interconnection Facility: The Sole-use facilities should include those which transmit power to radial customer loads if such facilities do not form a part of the connection to multiple transmission facilities that are subject to network power flows.
No
Please see our comments under Q5 where we comment on both the additions and modifications to the standards.



Application of FAC-003 for Gen Interconnect Facilities that are "two spans, generally 1/2 mile or more past the property line" is reasonable as long as the "property line" remains in the definition. OK.

Yes

There should be a clause that the TO shall be responsible for FAC-003 activities inside the TO's substation regardless of ownership of the Generation Interconnection Facility so we don't have to coordinate entry, etc. and they will likely have this handled for the bulk of their property anyway. R3 quarterly reporting of outage caused by vegetation is excessive for GOs. GOs would probably survey and cut as needed their Right of Ways at least once a year and probably already do so. TOs probably perform vegetation management on a multi-year cycle, so they might need to note quarterly if there is a veg. incident that occurs one or two quarters before the next round of survey/management on that line.

No

No SPS currently in system.

These responsibilities and authorities are already in place for other standards.

0-2 years

Currently establish training based on the RTO requirements. It would be Conectivâ€™s policy to continue this training for this requirement. If other training is imposed upon the Entities, it may require up to two years to develop and initiate full training.

0-2 years

Entity currently coordinates this operation with the TOP. If additional requirements are instituted by NERC, there may be a need to have time to develop new programs and policies to comply with additional requirements.

0-2 years

Coordination is required for the TOP to notify the GO/GOP of the decisions being implemented.

0-2 years

Entity currently coordinates this operation with the TOP. If additional requirements are instituted by NERC, there may be a need to have time to develop new programs and policies to comply with additional requirements.

0-2 years

Entity currently operates within the facility ratings as required under FAC. If additional requirements are instituted by NERC, there may be a need to have time to develop new programs and policies to comply with additional requirements

0-2 years

Entity currently coordinates this operation with the TOP. If additional requirements are instituted by NERC, there may be a need to have time to develop new programs and policies to comply with additional requirements.

Group

First Wind

Mary Jo Cooper

Yes

Yes

The proposed SAR modification set is the responsible approach to resolve gaps Generator Interconnection Facility gaps identified by the industry. The functions required of an Owner(s) and Operator(s) of facilities used to connect generation to the BES (Generator Interconnection Facilities) are not the same as the functions required to own and operate Transmission and should not be considered to be the same. We commend the task force for coming up with a reasonable approach that directly addresses reliability without requiring GO and GOPs to perform activities that have no bearing on the reliability of the BES.

No

We recommend the definition of Generator Interconnection Facility be modified. "Generator Interconnection Facility (NEW) A facility used for the sole purpose of connecting the generating unit(s) to the transmission grid. In this regard, the sole-use facility only transmits power associated with the interconnecting generator(s), whether delivered to the grid or delivered to the generator(s) for station service or auxiliary load, or delivered to meet cogeneration load requirements. The purpose of the above modification is to account for the situations where a Generator Operator may have many units, such as wind turbines, all using the same Generator Interconnection Facility to connect to the transmission grid. Additionally, we feel it is irrelevant if

the Generating Unit is owned by one or the same owners. Two scenarios explain why multiple generators using the same Generator Interconnection Facility does not serve a function of a TO or TOP. Scenario 1 Each Generator Operator is connected to the Transmission Operator through an independent Generator Interconnection Facility. There is no need for the Generator Operators to coordinate their operations with one another because their operations do not impact common facilities. However, there may be a need for the Transmission Operator to coordinate its instructions to the Generator Operators (if they issue voltage schedules, for example). When it becomes necessary for the Transmission Operator to communicate instructions to the Generator Operators, it is necessary for the Transmission Operator to communicate with each of the Generator Operators. Scenario 2 Generator Operator A is connected independently, but Generator Operators B and C share a common Generator Interconnection Facility. In this case, it is necessary for Generators B and C to coordinate their operations. It is not necessary to designate either GO\_B or GO\_C as the "operator" of the Generator Interconnections Facility. Rather, it is most appropriate to place the obligation to coordinate operations on both parties. By placing the obligation on both parties, they share an equal burden to comply with the applicable standards. Placing the obligation to coordinate operations on both GO\_B and GO\_C does not increase the burden to the Transmission Operator. If there is trouble at the point of interconnect substation, the Transmission Operator might need to coordinate operations with GO\_A, GO\_B and GO\_C in either Scenario 1 or Scenario 2. If in Scenario 2, the Transmission Operator only issued instructions to GO\_A and GO\_B, they could not be sure that GO\_C would receive the instructions. Furthermore, since GO\_B is not a Transmission Operator, they lack the authority to issue instructions to GO\_C. We recommend an additional requirement to resolve coordination between generators. For example "Generator Operators interconnected through a common Generator Interconnection Facility shall coordinate their operations."

No

We feel it is not necessary to include the phrase "including the Generator Interconnection Facility" in all the applicable requirements. The term Generator Interconnection Facility is proposed to be included in the Glossary definitions and the proposed definition of Generator Operator includes the following language "also operates the Generator Interconnection Facility and is responsible for coordinating with the Transmission Operator when the facility is energized or about to be energized to/de-energized from the transmission system" which we feel is sufficient and superior to having the phrase repeated throughout the applicable standards.

Yes

No

Immediately unless status requires change to additional requirements which might be 18 months to two years)

The Generator Interconnection Facilities are already considered to be part of our Generator Plant and therefore have already been included in our existing compliance program.

Less than 1 year

Memo from management should suffice.

2 years

Developing the training and providing it while accommodating shift employees will require a substantial amount of time.

Less than 1 year

There is already generator outage reporting protocols in place. This is just an addition to existing processes. Additionally, the Generator Interconnection Facility is already considered to be part of the Generating Facility and is likely already part of our existing compliance program.

less than 1 year

Expect that, in most cases, the Interconnection Agreement between the generator and the TO or DP that it connects with already contains language that supports this because the Generator Interconnection Facility is already considered to be part of the Generating Facility.

less than 1 year

Expect that, in most cases, the Interconnection Agreement between the generator and the TO or DP that it connects with already contains language that supports this.

less than 1 year

The Generator Interconnection Facility is already considered to be part of the Generator Unit and the facility should be compliant currently with FAC standards.

less than 1 year

The Generator Interconnection Facility is already considered to be part of the Generator Unit. Expect that, in most cases, the Interconnection Agreement between the generator and the TO or DP that it connects with already contains language that supports this.

FAC-003 " Step 4.5 should be clearly identified as a "qualifier" for Generator Owner

applicability. Although not the intent of the standard, as currently drafted, the requirements apply to all Generator Owners. Additionally we recommend modifications to address a disqualifier if the plant is located in an environment whose natural environment would prevent vegetation from growing that could interfere with the reliability of the bulk Electric System. The following changes are recommended. 4.4. Generator Owner. 4.5. This standard shall apply to the Generator Interconnection Facility above 200 kV that exceed two spans from the generator property linear are otherwise deemed critical by the Regional Entity below 200 kV (subject to the two-span criteria.). This standard does not apply to all Generator Interconnection Facilities outside this threshold and those facilities located in an area whose environment would prevent vegetation from growing. A generating facility located underground, in the high desert or within a fully developed urban area where vegetation disturbances could not occur should not be required to have a vegetation management program.  MOD-010  The changes made in this standard are not reflected in the associated standard, MOD-011 (possibly because MOD-011 is not FERC approved).  MOD-012  The changes made in this standard are not reflected in the associated standard, MOD-013 (possibly because MOD-013 is not FERC approved).  PER-001  The Purpose statement in the Standard needs to be modified to include GOP.  PER-002  The Purpose statement in the Standard needs to be modified to include GOP. We recommend the addition of PER-002 R3 is coordinated with the existing standard PRC-001 R1 to eliminate redundancy. While PER-002 R3 more clearly calls for training, PRC-001 R1 implies training. The two standards should be combined into one training requirement. PRC-001 R1   Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area. We recommend retiring PRC-001 R1 and modifying the proposed standard PER-002 R3 as shown below: Each Generator Operator shall implement an initial and continuing training program for all operating personnel that are responsible for operating the Generator Protection System Equipment, including the Generator Interconnection Facility that verifies the personnels ability and understanding to operate the equipment in a reliable manner.   TOP-002  Requirement R14 contains sub-requirements R14.1 and R14.2 that were retired August, 1, 2007. Suggest deleting the retired requirements with the proposed revision.  TOP-004  Requirement R7 has been added for the Generator Operator; however, the Generator Operation has not been added to the Applicability.  TOP-008  The Purpose statement in the Standard needs to be modified to include GOP.

Individual
Jason Shaver
American Transmission Company
Yes
Yes
Yes
No
Clarify the definition of generator interconnection facility to include who this applies to as shown in the conclusions above in #3. A Generator Interconnection Facility is considered as though part of the generating facility specifically for purposes of applying Reliability Standards to a Generator Owner or Generator Operator.
Yes
For FAC-009 [Establish and Communicate Facility Ratings], we believe that the additional wording to highlight that the term Facilities includes Generation Interconnection Facilities is superfluous, and therefore, it should not be added. The proposed new and revised definitions provide more than enough clarity For MOD-010 [Steady State Data for System Modeling], we believe that the additional wording of for plant and Generator Interconnection Facilities is superfluous, and therefore, it should not be added. The proposed new and revised definitions provide more than enough clarity. For MOD-012 [Dynamic System Data for System Modeling], we believe that the additional wording of for plant and Generator Interconnection Facilities is superfluous, and therefore, it should not be added. The proposed new and revised definitions provide more than enough clarity.
No





entities for which the NERC Standard is applicable, then the language in the NERC Standard should clearly state that intent.

Individual

Darcy O'Connell

California ISO

Yes

No

Adding language in several standards actually creates confusion rather than provide clarity. For example, EOP-003-1 (Load Shedding Plans) applies in situations when there is insufficient generation or transmission, requiring load shedding to avoid risk of uncontrolled failure of the interconnection. This function is generally accomplished through under frequency relay settings which will drop a pre-determined amount of load to maintain generation/load balance. Involving the Generator Operator to comply with this standard is unnecessary and may even complicate matters because the BA and the TOP will now have to coordinate with GOPs. Other similar examples are EOP-001-0, EOP-004-1, and TOP-001-1 where adding "Generator Interconnection Facility" does not add clarity but is rather redundant, and may create interpretation issues.

No

The definition for "Generator Interconnection Facility" (GIF) is not consistent with either Conclusion #1 of the Adhoc Group's final report, or with "Applicability 4.5" added under FAC-003-1. Conclusion #1 mentions "Generator Interconnecting Facilities operating at a voltage of 100 kV or greater or those deemed critical to the Bulk Electric System by the Regional Entity" and Applicability 4.5 mentions "Generator Interconnection Facility above 200 kV or are otherwise deemed critical by the Regional entity below 200 kV...". In both these instances it appears that the Adhoc Group is emphasizing those Generator Interconnection Facilities that are either part of the Bulk Electric System (BES) or deemed critical by the Regional entity. Therefore, we suggest modifying the definition as follows: First sentence, after the word grid, add "above 200 kV or otherwise deemed critical by the Regional entity below 200 kV".

Yes

No

Please see our comments under Question 2 above. In addition, with regard to the proposed change to Standard PRC-001, the California ISO (CAISO) questions the need for a BA to understand the purpose and limitations of protection schemes associated with all of the Generator Interconnection Facilities in its area given a BA's role is to balance load/generation/interchange which does not require the BA to operate any generator or BES facilities, or to understand the characteristics or limitations of any equipment. Any potential loss of one or more generator due to protection or equipment issues will need to be communicated by the GO or GOP to the BA for consideration in reserve calculation

No

We are not a GOP and hence we are unable to comment on this and other questions addressing the GOP compliance. However, the CAISO has the following comments on the effort required for other aspects of this Project: "As discussed under the answer to Question 5 above, it is not clear if the proposed changes to PRC-001 will require the Balancing Authority (BA) to understand the purpose and limitations of protection schemes associated with all of the Generator Interconnection Facilities in its area, even if such facilities are not under the control of the BA. If this is the case, significant and time-consuming effort will be required to identify the technical details of all of the Generator Interconnection Facilities in the BA and develop a training program to train applicable personnel on them. This is estimated to require up to 24 months. If the proposed changes are approved they will affect 16 Standards affecting CAISO registrations. Most, if not all, of these changes will require modifications to the Reliability Standards Agreements (RSAs) between the CAISO and its Participating Transmission Operators to reflect the new wording and any delegated tasks. This may require 12 to 24 months to implement.





The PSEG Companies support this approach to ensure that all components of the BES are adequately covered by the reliability standards. The drafting team has done a good job of identifying the appropriate areas of concern.

Individual

Marcus Lotto

Southern California Edison co.

Yes

Yes

Yes

Additional clarification would be useful as it/ they would cut down on future requests for interpretation... i.e provide a specific threshold for the proposed Generator interconnection Facility definition

Yes

Additional clarification would be useful as it/ they would cut down on future requests for interpretation.

Yes

Additional clarification would be useful as it/ they would cut down on future requests for interpretation

No

Do not feel that this question is in the scope of Project 2010-07 as written

3yrs

Pls refer to question No. 8

3yrs

Pls refer to question No. 8

3yrs

Pls refer to question No. 8

3yrs

Pls refer to question No. 8

3yrs

Pls refer to question No. 8

3yrs

Pls refer to question No. 8

3yrs

Pls refer to question No. 8

3yrs

Pls refer to question No. 8

SCE believes that implementing changes type of changes proposed in 2010-07 should be looked at as a whole/ one entire project rather than piece meal as alluded to in question number 7 of the comments form. As such, it is the company's position that approximately 3yrs is right amount of time to reliably implement the proposed revisions to the suite of standards as identified in Project 2010-07. A 3 yr timeline would enable the project to be fully scoped out and budgeted, and allow for: completion of the necessary engineering studies; design, procurement and construction of any new facilities necessitated by the revisions; development of any new operations and communications procedures with respect to both the transmission and generation facilities; and the training of personnel related to any new procedures.

Group

Kansas City Power & Light
Michael Gammon
No
There is a need to bring clarity to the Reliability Standards regarding the delineation of what the Generator Owner and Generator Operator is responsible for and for definitions distinguishing between Generator Operators at Power Plants and "Generator Operator" as the "Power System Operator" directing a fleet of generators in a balancing area. I do not believe reliability of the interconnected grid has suffered as a result of the shortcomings of the Reliability Standards in this regard as the electric industry has continued to operate in a responsible manner.
Yes
No
I believe the intent of what has been proposed here is to define the term, "Generator Operator" to mean the Operator that operates units directly at a power station. With that in mind, although the proposed definition is close, I believe the interaction with the Transmission Operator only in the definition makes this confusing. Recommend consideration of the following definition: The entity that operates generating unit(s) and the Generator Interconnection Facility and performs the functions of supplying energy and reactive power as directed by the Balancing Authority and the Transmission Operator. The Generator Operator may also operate the Generator Interconnection Facility and is responsible for coordinating with the Balancing Authority and the Transmission Operator when the facility is energized or about to be energized to/de-energized from the transmission system. In addition, recommend adding the generating station property line to the definition for Generator Interconnection Facility for clarity: Sole-use facility that leaves generator property line for the purpose of connecting the generating unit(s) to the transmission grid. In this regard, the sole-use facility only transmits power associated with the interconnecting generator, whether delivered to the grid or delivered to the generator for station service or auxiliary load, or delivered to meet cogeneration load requirements.
No
â€¢ PER-001, R1: The language proposed for PER-001, R1, infers the Generator Operator is able to take independent actions regarding the "Generation Facility" and the Generator Interconnection Facility. There is no definition for Generation Facility in this proposal or currently in the NERC Glossary. At any rate, do not agree with the Generator Operator taking any independent actions other than those to monitor and maintain the safe operation of a generating unit for the production of energy and reactive power. â€¢ PER-002, R3 (Proposed here): This infers again the Generator Operator taking independent actions with regard to equipment within the Generator Interconnection Facility. Although, the Generation Interconnection Facility is defined properly, that does not mean the Generator Operator is the control authority over that equipment. It is not uncommon for the Generator Operator to operate equipment within the Generator Interconnection Facility at the direction of the Transmission Operator. Recommend consideration be given to modify this requirement to reflect that. â€¢ TOP-001, R9 and R10 (Proposed here): This infers again the Generator Operator taking independent actions with regard to equipment within the Generator Interconnection Facility. Although, the Generation Interconnection Facility is defined properly, that does not mean the Generator Operator is the control authority over that equipment. It is not uncommon for the Generator Operator to operate equipment within the Generator Interconnection Facility at the direction of the Transmission Operator. Recommend consideration be given to modify these requirements to reflect the Transmission Operator can be the authority over the equipment within the Generation Interconnection Facility but that the Generator Operator may operate that equipment at the direction of the Transmission Operator.
Yes
No
Not at this time.
12 months
Basically this is a training issue. It takes time to prepare the training materials and to train all Generator Operators considering shift schedules and to implement the training as part of an ongoing process.
N/A
The Generator Operator should be operating equipment within the Generator Interconnection Facility at the direction of the Transmission Operator.
N/A
The Generator Operator should be operating equipment within the Generator Interconnection Facility at the direction of the Transmission Operator.
6 months

If this is not already going on, this should not take long to implement.
6 months
If this is not already going on, this should not take long to implement.
6 months
If this is not already going on, this should not take long to implement.
6 months
If this is not already going on, this should not take long to implement.
6 months
If this is not already going on, this should not take long to implement.
No other comments.

## Consideration of Comments on Generator Requirements at the Transmission Interface — Project 2010-07

The GOTO Drafting Team thanks all commenters who submitted comments on the proposed SAR and modifications to several reliability standards and NERC Glossary terms associated with the recommendations of the Generator Requirements at the Transmission Interface Ad Hoc Group, embodied in Project 2010-07. These standards were posted for a 30-day public comment period from February 12, 2010 through March 15, 2010. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 41 sets of comments, including comments from more than 80 different people from over 60 companies representing 7 of the 10 Industry Segments as shown in the table on the following pages.

In this report, comments have been organized by question number. All comments may be reviewed in their original format on the following web page:

[http://www.nerc.com/filez/standards/Project2010-07\\_GOTO\\_Project.html](http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html)

Based on stakeholder comments, along with discussions with FERC and NERC staff, the SAR drafting team (SAR DT) made the following modifications to the SAR:

- Gave the Standard Drafting Team (SDT) the flexibility to include additional standards not originally identified in the Ad Hoc Task Force Report
- With respect to new terms and modifications of definitions of terms, the SAR DT made it clearer that the SDT can adopt proposals as indicated in the Ad Hoc Task Force Report or modify them to address stakeholder concerns
- Gave the SDT the option of merging the Ad Hoc Task Force's proposed changes into one new standard or an existing standard(s) if deemed appropriate
- Language changes for clarity

Some commenters indicated that the SAR as written was too broad, but the SDT believes that giving the SDT as many options as possible is advantageous. The SDT will be the team to ultimately determine which standards should be modified.

Many commenters made specific recommendations for modifications to standards. The SAR DT has compiled those comments for use during the next phase of this project, standard drafting. In particular, the comments on Question 7 and its subcomponents were intended to provide input for the SDT in the development of its implementation plan to accompany the project as it moves forward. The most frequently cited challenges – training, agreements, and technical details – will be considered by the SDT.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 315-439-1390 or at [herb.schrayshuen@nerc.net](mailto:herb.schrayshuen@nerc.net). In addition, there is a NERC Reliability Standards Appeals Process.<sup>1</sup>

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<sup>1</sup> The appeals process is in the Reliability Standards Development Procedures:  
<http://www.nerc.com/standards/newstandardsprocess.html>.

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**Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07**

The Industry Segments are:

- 1 — Transmission Owners
- 2 — RTOs, ISOs
- 3 — Load-serving Entities
- 4 — Transmission-dependent Utilities
- 5 — Electric Generators
- 6 — Electricity Brokers, Aggregators, and Marketers
- 7 — Large Electricity End Users
- 8 — Small Electricity End Users
- 9 — Federal, State, Provincial Regulatory or other Government Entities
- 10 — Regional Reliability Organizations, Regional Entities

		Commenter	Organization	Industry Segment										
				1	2	3	4	5	6	7	8	9	10	
1.	Group	Philip R. Kleckley	SERC Planning Standards Subcommittee	X		X		X						
		<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>			<b>Segment Selection</b>							
1.	John Sullivan	Ameren Services Company	SERC				1							
2.	Charles Long	Entergy	SERC				1							
3.	James Manning	North Carolina Electric Membership Corporation	SERC				3							
4.	Pat Huntley	SERC Reliability Corporation	SERC				10							
5.	Bob Jones	Southern Company Services, Inc. - Transmission	SERC				1							
2.	Group	Guy Zito	Northeast Power Coordinating Council											X
		<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>			<b>Segment Selection</b>							
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC				10							
2.	Gregory Campoli	New York Independent System Operator	NPCC				2							
3.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC				2							
4.	Kurtis Chong	Independent Electricity System Operator	NPCC				2							
5.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC				1							
6.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC				1							

Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07

	Commenter	Organization	Industry Segment														
			1	2	3	4	5	6	7	8	9	10					
7.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC									10					
8.	Ben Eng	New York Power Authority	NPCC									4					
9.	Brian Evans-Mongeon	Utility Services	NPCC									8					
10.	Mike Garton	Dominion Resources Services, Inc.	NPCC									5					
11.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC									5					
12.	Kathleen Goodman	ISO - New England	NPCC									2					
13.	David Kiguel	Hydro One Networks Inc.	NPCC									1					
14.	Michael R. Lombardi	Northeast Utilities	NPCC									1					
15.	Randy MacDonald	New Brunswick System Operator	NPCC									2					
16.	Greg Mason	Dynegy Generation	NPCC									5					
17.	Bruce Metruck	New York Power Authority	NPCC									6					
18.	Chris Orzel	FPL Energy/NextEra Energy	NPCC									5					
19.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC									10					
20.	Robert Pellegrini	The United Illuminating Company	NPCC									1					
21.	Saurabh Saksena	National Grid	NPCC									1					
22.	Michael Schiavone	National Grid	NPCC									1					
23.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC									3					
3.	Group	Rick Terrill	Luminant						X								
4.	Group	Jalal Babik	Electric Market Policy	X		X		X	X								
		<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>					<b>Segment Selection</b>								
1.	Louis Slade		SERC									5					
2.	Mike Garton		NPCC									6					
5.	Group	Ben Li	ISO RTO Council Standards Review Committee		X												
		<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>					<b>Segment Selection</b>								
1.	Patrick Brown		PJM									2					
2.	Jame Castle		NYISO									2					



Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
3.		Lourdes Estrada-Salinero	CAISO	WECC						2			
4.		Matt Goldberg	ISO NE	NPCC						2			
5.		Steve Myers	ERCOT	ERCOT						2			
6.		Bill Phillips	MISO	RFC						2			
7.		Mark Thompson	AESO	WECC						2			
8.		Charles Yeung	SPP	SPP						2			
6.	Group	Jason L. Marshall	Midwest ISO Standards Collaborators		X								
		Additional Member	Additional Organization	Region					Segment Selection				
1.		Steve Rose	CWLP	SERC					1				
2.		Jim Cyrulewski	JDRJC Associates, LLC	RFC					8				
3.		Joe Knight	Great River Energy	MRO					1, 3, 5, 6				
4.		Barb Kedrowski	We Energies	RFC					3, 4, 5				
5.		Sam Ciccone	First Energy	RFC					1, 3, 4, 5, 6				
6.		Doug Hohlbaugh	First Energy	RFC					1, 3, 4, 5, 6				
7.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				
		Additional Member	Additional Organization	Region					Segment Selection				
1.			City of Vero Beach	FRCC					3				
2.			City of New Smyrna Beach	FRCC					3				
3.			Kissimmee Utility Authority	FRCC					3				
4.			Lakeland Electric	FRCC					3				
5.			City of Clewiston	FRCC					3				
6.			Beaches Energy Services	FRCC					1				
7.			Fort Pierce Utility Authority	FRCC					4				
8.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				
		Additional Member	Additional Organization	Region					Segment Selection				
1.		Jim Burns	BPA, Transmission Technical Operations	WECC					1				

Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
9.	Group	Richard Kafka	Pepco Holdings, Inc - Affiliates	X		X		X	X				
		<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>						<b>Segment Selection</b>			
		1. Kara Dundas	Conectiv Energy Supply, Inc	RFC						5			
		2. Don Bridge	Conectiv Energy Supply, Inc	RFC						5			
		3. James Newton	Pepco Energy Services	RFC						5			
10.	Group	Mary Jo Cooper	First Wind					X					
		<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>						<b>Segment Selection</b>			
		1. First Wind O&M, LLC		NPCC						5			
		2. Canandaigua Power Partners, LLC		NPCC						5			
		3. Canandiagu Power Partners II, LLC		NPCC						5			
		4. Milford Wind Coordin Phase I, LLC		WECC						5			
		5. Stetson Wind II, LLC		NPCC						5			
		6. Evergreen Wind Power V, LLC		NPCC						5			
11.	Group	Kenneth D. Brown	PSEG Companies	X		X		X	X				
		<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>						<b>Segment Selection</b>			
		1. Jim Hebson	PSEG ER&T	NPCC						6			
		2. Dave Murray	PSEG Fossil	ERCOT						5			
		3. Jim Hubertus	PSE&G	RFC						1, 3			
12.	Group	Michael Gammon	Kansas City Power & Light	X		X		X	X				
		<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>						<b>Segment Selection</b>			
		1. Jim Useldinger	KCPL	SPP						1, 3, 5, 6			
		2. Jennifer Flandermeyer	KCPL	SPP						1, 3, 5, 6			
		3. Nick McCarty	KCPL	SPP						1, 3, 5, 6			
		4. Melinda Mangold	KCPL	SPP						1, 3, 5, 6			
		5. Dennis Greashaber	KCPL	SPP						1, 3, 5, 6			
		6. Jerry Hatfield	KCPL	SPP						1, 3, 5, 6			

Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07

		Commenter	Organization	Industry Segment										
				1	2	3	4	5	6	7	8	9	10	
7.	Tom Saitta		KCPL	SPP						1, 3, 5, 6				
8.	Harold Wyble		KCPL	SPP						1, 3, 5, 6				
13.	Individual	Jack Cashin	Energy Standards Working Group											
14.	Individual	Brent Ingebrigtsen	E.ON U.S.	X		X		X	X					
15.	Individual	Silvia Parada-Mitchell	Transmission Owner/Generation Owner	X		X		X	X					
16.	Individual	Larry Rodriguez	Entegra Power Group LLC					X	X					
17.	Individual	Ken Parker	Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners		X									
18.	Individual	Jack Stamper	Public Utility District #1 of Clark County	X										
19.	Individual	Daniel E. Kujala	Detroit Edison Company			X		X						
20.	Individual	Mark Bennett	Competitive Power Ventures, Inc.					X						
21.	Individual	Sam Dwyer	AmerenUE, Power Operations Services					X						
22.	Individual	Amir Hammad	Constellation Power Source Generation Inc.					X						
23.	Individual	Alisha Anker	Prairie Power, Inc.			X								
24.	Individual	Michelle D'Antuono	Ingleside Cogeneration, LP					X						
25.	Individual	Katy Mirr	Sempra Generation					X						
26.	Individual	Robert Ellis	Mesquite Power	X				X						
27.	Individual	Jon Kapitz	Xcel Energy	X		X		X	X					

**Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07**

		Commenter	Organization	Industry Segment										
				1	2	3	4	5	6	7	8	9	10	
28.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X					
29.	Individual	James Sharpe	South Carolina Electric and Gas	X		X		X	X					
30.	Individual	Scott Helyer	Tenaska, Inc.					X						
31.	Individual	Kevin Gillespie	El Dorado Energy LLC					X						
32.	Individual	Patti Metro	National Rural Electric Cooperative Association (NRECA)			X	X							
33.	Individual	Greg Rowland	Duke Energy	X		X		X	X					
34.	Individual	James H. Sorrels, Jr.	American Electric Power	X		X		X	X					
35.	Individual	James Manning, Bob Beadle, Doug White, and Richard McCall	North Carolina Electric Membership Corporation			X	X	X						
36.	Individual	Dan Rochester	Independent Electricity System Operator		X									
37.	Individual	Jason Shaver	American Transmission Company	X										
38.	Individual	Laura Zotter	ERCOT ISO		X									
39.	Individual	Darcy O'Connell	California ISO											X
40.	Individual	Alice Murdock	Xcel Energy	X		X		X	X					
41.	Individual	Marcus Lotto	Southern California Edison co.	X		X		X	X					

1. Do you agree that there is a reliability-related need for the proposed standards action?

**Summary Consideration:** The overwhelming majority of stakeholder comments affirmed the need for this proposed standard action.

Organization	Yes or No	Question 1 Comment
E.ON U.S.	No	E.ON U.S. has already determined a Division of Responsibilities between the GO/TO and therefore does not see the need for auditable reliability standards to be added between the GO/TO.
<p><b>Response:</b> The SAR DT thanks you for your comment. Based on a review of the full body of industry comments, we believe that there is a reliability need for this SAR.</p>		
Luminant	No	In general, Luminant agrees there is a need to address generation facilities with extended connections to the transmission system. However, Luminant does not agree there is a reliability need for the proposed standards action as it relates to generators connected in close proximity to the grid where the connection typically consists of a bus or short wires connection from the high side of a generator step up transformer to the generator breaker.
<p><b>Response:</b> The SAR DT thanks you for your comment. Based on a review of the full body of industry comments, we believe that there is a reliability need for this SAR.</p>		
Kansas City Power & Light	No	There is a need to bring clarity to the Reliability Standards regarding the delineation of what the Generator Owner and Generator Operator is responsible for and for definitions distinguishing between Generator Operators at Power Plants and “Generator Operator” as the “Power System Operator” directing a fleet of generators in a balancing area. I do not believe reliability of the interconnected grid has suffered as a result of the shortcomings of the Reliability Standards in this regard as the electric industry has continued to operate in a responsible manner.
<p><b>Response:</b> The SAR DT thanks you for your comment. Based on a review of the full body of industry comments, we believe that there is a reliability need for this SAR. And while we respect your concern about the definition of Generator Operator versus Power System Operator, we maintain that it is outside the scope of this SAR.</p>		
Detroit Edison Company	No	Vegetation Inspection change to include any BES component Transmission Line or Generator Interconnection Facility Right-of-Way or any other BES component to document vegetation conditions.
<p><b>Response:</b> Thank you for your comment. Based on the SAR DT’s interpretation of this comment, we believe it is outside the scope of the SAR.</p>		

**Consideration of Comments on Generator Requirements at the Transmission Interface — Project 2010-07**

Organization	Yes or No	Question 1 Comment
AmerenUE, Power Operations Services	Yes	
American Electric Power	Yes	
American Transmission Company	Yes	
Bonneville Power Administration	Yes	
California ISO	Yes	
Duke Energy	Yes	
El Dorado Energy LLC	Yes	
Electric Market Policy	Yes	
Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners	Yes	
ERCOT ISO	Yes	
First Wind	Yes	

**Consideration of Comments on Generator Requirements at the Transmission Interface — Project 2010-07**

Organization	Yes or No	Question 1 Comment
Florida Municipal Power Agency	Yes	
Independent Electricity System Operator	Yes	
ISO RTO Council Standards Review Committee	Yes	
Mesquite Power	Yes	
Midwest ISO Standards Collaborators	Yes	
National Rural Electric Cooperative Association (NRECA)	Yes	
North Carolina Electric Membership Corporation	Yes	
Prairie Power, Inc.	Yes	
PSEG Companies	Yes	
Public Utility District #1 of Clark	Yes	

Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07

Organization	Yes or No	Question 1 Comment
County		
Sempra Generation	Yes	
SERC Planning Standards Subcommittee	Yes	
South Carolina Electric and Gas	Yes	
Southern California Edison co.	Yes	
Xcel Energy	Yes	
Xcel Energy	Yes	
Entegra Power Group LLC	Yes	But, that action should be reasonable, provide specific detail, and be kept simple so the reliability-related objectives are effectively understood by those operators of the GI Facilities.
<b>Response:</b> The SAR DT thanks you for your comment.		
Energy Standards Working Group	Yes	EPSA members, through active participation in many NERC activities including the team that prepared the report and the attached SAR, are strong advocates of mandatory standards to protect reliability of the Grid. We also strongly agree that there is a need for greater clarity of the responsibilities of Generator Owner/Operators and Transmission Owner/Operators at the Generator Interconnection Interface and thus concur with the direction of this SAR that this should be achieved without the need for Generator Owner/Operators to be included in the registry as Transmission Owner/Operators.
<b>Response:</b> The SAR DT thanks you for your comment.		
Competitive Power	Yes	In fact, the technical analysis in the Ad Hoc Group's Report provides a valuable and useful understanding of the specific nature and extent of reliability issues associated with generator interconnection facilities. Up to now, the need for generator



**Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07**

Organization	Yes or No	Question 1 Comment
Ventures, Inc.		TO/TOP registrations has not been supported by a clear and technically sound rationale. The Report's conclusion, based upon its comprehensive and thorough review, that there is no need for generators to be registered as TO/TOPs to address the specific reliability issues is especially significant.
<b>Response:</b> The SAR DT thanks you for your comment.		
Ingleside Cogeneration, LP	Yes	Ingleside Cogeneration, LP believes that the effort by the Ad Hoc Group for Generator Requirements at the Transmission Interface has generally succeeded in developing criteria clarifying the ownership and operational responsibilities of registered generation and transmission entities at their point of interface. This is an important body of work which needs to result in an end to the forced registration of Generator Owners/Operators (GO/GOP) as Transmission Owner/Operators (TO/TOP) by Regional Entities.
<b>Response:</b> The SAR DT thanks you for your comment.		
Pepco Holdings, Inc - Affiliates	Yes	It is difficult to say if there is a “reliability-related need”. Most GOs operate and maintain their Generator Interconnection Facility in the same manner as the rest of their generation facilities. It is beneficial to differentiate between the “Generation Interconnection Facility” and the “Transmission” system so that GOs do not have to be registered as TOs.
<b>Response:</b> The SAR DT thanks you for your comment.		
Tenaska, Inc.	Yes	Tenaska actively participates in many NERC activities, including the team that prepared the report and the attached SAR/Draft Standards, and strongly advocates the need for reliability of the system. We also strongly agree that there is a need for greater clarity of the responsibilities of Generator Owner/Operators and Transmission Owner/Operators at the Generator Interconnection Interface and thus concur with the direction of this SAR that this should be achieved without the need for Generator Owner/Operators to be included in the registry as Transmission Owner/Operators.
<b>Response:</b> The SAR DT thanks you for your comment.		
Manitoba Hydro	Yes	With the implementation of the new Glossary Terms, this will clarify the dividing point between GO and TO.
<b>Response:</b> The SAR DT thanks you for your comment.		
Constellation Power Source	Yes	Yes - Defining the compliance responsibility to align more accurately with operational reality is important in managing reliability. However, the SDT must also consider those entities that enter into a Joint Registration Organization (“JRO”) for certain GOP reliability standards. This registration exception applies to market entities, where there has been a JRO created

**Consideration of Comments on Generator Requirements at the Transmission Interface — Project 2010-07**

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Organization	Yes or No	Question 1 Comment
Generation Inc.		that delineates specific joint responsibilities, with respect to the GOP reliability standards. It is incumbent on both parties to comply with their agreed upon respective responsibility.
<b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT for their consideration.		

2. Do you agree with the scope of the proposed standards action?

**Summary Consideration:** While there were a number of responses that indicated the SAR was too broad, an in-depth review of the comments indicated that most of the concerns could be addressed by modifications to the proposed standards changes included in the Ad Hoc Report. As a result, many of these comments will be referred to the SDT for their consideration, including final resolution of which standards need to be modified. Based on discussions with FERC and NERC staffs regarding previous Commission actions and NERC compliance filings, the SAR DT also elected to give the SDT the flexibility to include additional standards (now listed in the modified SAR) not identified in the Ad Hoc Report.

Organization	Yes or No	Question 2 Comment
American Electric Power	No	
Luminant	No	Luminant believes the scope of the standards action significantly exceeds the reliability need. The scope should only extend to Generation Interconnection Facilities of greater than one-half (½) mile in length from the property boundary of the generation plant. This standards action should only be applied where there is a demonstrated reliability benefit. For the bulk of the Generator Owners, the proposal creates excessive documentation and paperwork, and increases compliance risk with no reliability benefit to the Bulk Electric System (BES).
<p><b>Response:</b> The SAR DT thanks you for your comment. Based on a review of the full body of industry comments, we believe that the standards actions proposed in this SAR are appropriate. Specific modifications will be determined by the SDT.</p>		
California ISO	No	Adding language in several standards actually creates confusion rather than provide clarity. For example, EOP-003-1 (Load Shedding Plans) applies in situations when there is insufficient generation or transmission, requiring load shedding to avoid risk of uncontrolled failure of the interconnection. This function is generally accomplished through under frequency relay settings which will drop a pre-determined amount of load to maintain generation/load balance. Involving the Generator Operator to comply with this standard is unnecessary and may even complicate matters because the BA and the TOP will now have to coordinate with GOPs. Other similar examples are EOP-001-0, EOP-004-1, and TOP-001-1 where adding “Generator Interconnection Facility” does not add clarity but is rather redundant, and may create interpretation issues.
<p><b>Response:</b> The SAR DT thanks you for your comment. Based on a review of the full body of industry comments, we believe that the standards actions proposed in this SAR are appropriate. Specific modifications will be determined by the SDT.</p>		
Public Utility District #1 of Clark	No	Clark Public Utilities believes the scope of the proposed standards actions is too broad.

Consideration of Comments on Generator Requirements at the Transmission Interface — Project 2010-07

Organization	Yes or No	Question 2 Comment
County		
<p><b>Response:</b> The SAR DT thanks you for your comment. Based on a review of the full body of industry comments, we believe that the standards actions proposed in this SAR are appropriate.</p>		
E.ON U.S.	No	E.ON U.S. has already determined a Division of Responsibilities between the GO/TO and therefore does not see the need for auditable reliability standards to be added between the GO/TO.
<p><b>Response:</b> The SAR DT thanks you for your comment. Based on a review of the full body of industry comments, we believe that the standards actions proposed in this SAR are appropriate.</p>		
Florida Municipal Power Agency	No	<p>FAC-003 should not be applicable to Generator Owners / Operators. The intent of all of the standards is to avoid an Adverse Reliability Impact, or as the FPA Section 215(a)(4) defines “reliable operations” as: “operating the elements of the bulk-power system within equipment and electric system thermal, voltage and stability limits so that instability, uncontrolled separation, or cascading failures of such systems will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.” Radial Facilities serving only generating plants when tripped will not threaten an Adverse Reliability Impact or we would be hard pressed to run that generation in the first place.FMPA believes the intent of the standard is to prevent a cascading event where, if a line trips, another line loads heavily increasing the sag of that line, which may sag into un-cleared vegetation, causing the second line to trip, which may in turn cause heavily loading on a third line, etc. If a line trips in the transmission network, radial Facilities from generating plants will not have their loading changed much at all (since they are radial) and will not participate in this sort of “thermal” cascading event. Hence, there is no cause to regulate vegetation management of radial Facilities to generating plants since the system is always planned and operated to that potential contingency anyway and there is no danger of an Adverse Reliability Impact. Regulating vegetation management on radial Facilities is beyond the scope of the Federal Power Act Section 215.Generator Owners / Operators are still incited to perform adequate vegetation management without the need for regulation because any outage of the plant results in lost opportunity costs to the plant.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Based on a review of the full body of industry comments, we believe that the standards actions proposed in this SAR are appropriate. Specific modifications will be determined by the SDT.</p>		
Ingleside Cogeneration, LP	No	<p>No. Ingleside Cogeneration, LP believes there is a secondary, but equally important issue which we believe has not been fully addressed in the proposed SAR. There can be components of the Generator Interconnection Facility located on the Generator Owner’s property, but are maintained by the Transmission Owner. An excellent example is the relays protecting the interconnected transmission line. Although these are usually purchased by the Generator Owner and are financially carried on their books, in some cases the Transmission Owner performs the associated maintenance and testing. This arrangement can</p>

Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07

Organization	Yes or No	Question 2 Comment
		<p>make sense as the relays are protecting a transmission system and must properly interact with relays on the other side of the transmission line through associated communications systems. This kind of arrangement can lead to a variety of interpretations by auditors even when presented with an Interconnection Agreement specifying the ownership/maintenance arrangement. We believe that if the responsibility to a requirement is clearly delineated in a formal document, the associated collection and presentation of evidence of compliance is part of that responsibility - in this case the TO owning maintenance and testing of protective relays financially owned by the GO. The Exclusion statement under Section III.c.4 of the Statement of Compliance Registry Criteria allows for compliance responsibility to be transferred to another entity provided it registers as the appropriate entity. In addition, we recognize that Sections 501 and 507 of the NERC Rules of Procedure allows distribution of responsibility among two or more entities through a Joint Registration - although that process is designed for tightly connected organizations such as joint ventures or cooperatives.</p> <p>We recommend these all-or-nothing approaches be modified in the exclusion as suggested below:</p> <p style="padding-left: 40px;">A generator owner/operator will not be registered based on these criteria if responsibilities for compliance with approved NERC reliability standards or associated requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, such as a load-serving entity, G&amp;T cooperative or joint action agency as described in Sections 501 and 507 of the NERC Rules of Procedure. "Responsibility for individual requirements applicable to the Generator Interconnection Facility including reporting can be transferred by written agreement without a change to an entity's registration."</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. It is outside the scope of both the SAR DT and the SDT to propose changes to the NERC Rules of Procedure.</p>		
ISO RTO Council Standards Review Committee	No	Please see our comments under Q8.
<p><b>Response:</b> The SAR DT thanks you for your comment. Based on a review of the full body of industry comments, we believe that the standards actions proposed in this SAR are appropriate. Specific modifications will be determined by the SDT.</p>		
Constellation Power Source Generation Inc.	No	Please see the comments for Question #4: Constellation agrees with the proposed new requirements in principal. However, further clarity is needed in the requirements so that there isn't any added confusion. Either an implementation plan or a "frequently asked questions" document would be recommended.
<p><b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT.</p>		

Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07

Organization	Yes or No	Question 2 Comment
Prairie Power, Inc.	No	PPI believes the group has extended the scope too broadly from its initial intent as described in comments below.
<p><b>Response:</b> The SAR DT thanks you for your comment. Based on a review of the full body of industry comments, we believe that the standards actions proposed in this SAR are appropriate. Specific modifications will be determined by the SDT.</p>		
AmerenUE, Power Operations Services	No	While we agree with the overall scope of the proposed actions, there appears to be one missing critical element. What requirement will ensure that each GO, GOP, TO and TOP agree on the specifics of implementing these new requirements for each GIF? Has the Ad Hoc Group considered adding a requirement to mandate execution of an Agreement or Procedure between the GO, GOP, TO and TOP to ensure minimal specific actions that would guarantee compliance with each GIF Requirement?
<p><b>Response:</b> The SAR DT thanks you for your comment. The SAR has been modified to allow the SDT the option of merging the changes into one new standard or an existing standard(s).</p>		
American Transmission Company	Yes	
Bonneville Power Administration	Yes	
Competitive Power Ventures, Inc.	Yes	
Detroit Edison Company	Yes	
Duke Energy	Yes	
El Dorado Energy LLC	Yes	
Electric Market	Yes	

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Organization	Yes or No	Question 2 Comment
Policy		
Energy Standards Working Group	Yes	
Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners	Yes	
ERCOT ISO	Yes	
Independent Electricity System Operator	Yes	
Kansas City Power & Light	Yes	
Manitoba Hydro	Yes	
Mesquite Power	Yes	
Midwest ISO Standards Collaborators	Yes	
North Carolina Electric Membership Corporation	Yes	
PSEG Companies	Yes	

Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07

Organization	Yes or No	Question 2 Comment
Sempra Generation	Yes	
SERC Planning Standards Subcommittee	Yes	
South Carolina Electric and Gas	Yes	
Southern California Edison co.	Yes	
Tenaska, Inc.	Yes	
Entegra Power Group LLC	Yes	<p>BUT, FAC-003 SHOULD BE APPLIED IN A REASONABLE MANNER. MORE DETAIL SHOULD BE PROVIDED THAN IT WOULD APPLY FOR MORE THAN 2 SPANS. WHAT IF THERE ARE 3 SPANS, BUT ONLY A QUARTER MILE IN DISTANCE WHICH IS TOTALLY VISIBLE FROM THE GIF. THE SDT SHOULD MAKE SOME REASONABLE CONCESSIONS FOR THESE SITUATIONS, OR ALLOW THE GIF TO DOCUMENT THE SOUND REASONING USED IN NOT IMPLEMENTING FAC-003 TO THE EXTENT REQUIRED BY THE EXISTING STANDARD. A REASONABLE VEGETATION MANAGEMENT PROGRAM SHOULD BE ADEQUATE. MORE DETAIL AND SPECIFICS DESCRIBING WHAT ADEQUATE TRAINING IS FOR PER-002.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT.</p>		
Pepco Holdings, Inc - Affiliates	Yes	<p>Defining “Generator Interconnection Facility” in the glossary is a good idea. Going beyond this to specifically note this term in so many other standards seems unnecessary since other individual devices are not noted in so many other locations. If “Generator Interconnection Facility” is included in all other Generating Facilities, this may simplify the process.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
First Wind	Yes	<p>The proposed SAR modification set is the responsible approach to resolve gaps Generator Interconnection Facility gaps identified by the industry. The functions required of an Owner(s) and Operator(s) of facilities used to connect generation to the</p>



**Consideration of Comments on Generator Requirements at the Transmission Interface — Project 2010-07**

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Organization	Yes or No	Question 2 Comment
		BES (Generator Interconnection Facilities) are not the same as the functions required to own and operate Transmission and should not be considered to be the same. We commend the task force for coming up with a reasonable approach that directly addresses reliability without requiring GO and GOPs to perform activities that have no bearing on the reliability of the BES.
<b>Response:</b> The SAR DT thanks you for your comment.		

**3. Do you agree with the proposed NERC Glossary additions or revisions? If you disagree with one or more of the proposed new or modified definitions, please provide a revision that would make the definition acceptable to you.**

**Summary Consideration:** While a majority of comments did not challenge the need for the proposed new definitions, some did suggest modifications to those new terms, as well as to some existing terms defined in the *NERC Glossary of Terms*. Given this, the SAR DT modified the SAR to make it clearer that the SDT can adopt proposals as indicated in the report or modify them to address stakeholder concerns expressed in responses to the SAR DT questionnaire.

Organization	Yes or No	Question 3 Comment
Xcel Energy		Should the definition of Generator Interface Facility indicate that no BES (or any) loads be tapped between the generator and the GIF operational interface?
<b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT.		
Independent Electricity System Operator	No	(1) Generator Operator: We agree with the first sentence of the definition for Generator Operator, but do not agree with the need for the second sentence. The first sentence already states inclusion of Generator Interconnection Facility. The first part of the second is simply a repeat of this change. The latter part of the second sentence is a requirement that should be stipulated in an appropriate standard. We suggest to strike out the second sentence. (2) Generator Interconnection Facility: The Sole-use facilities should include those which transmit power to radial customer loads if such facilities do not form a part of the connection to multiple transmission facilities that are subject to network power flows.
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		
ISO RTO Council Standards Review Committee	No	(1) Generator Operator: We agree with the first sentence of the definition for Generator Operator, but do not agree with the need for the second sentence. The first sentence already states inclusion of Generator Interconnection Facility. The first part of the second is simply a repeat of this change. The latter part of the second sentence is a requirement that should be stipulated in an appropriate standard. We suggest to strike out the second sentence.
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		
Duke Energy	No	<ul style="list-style-type: none"> <li>o The definitions of Generator Owner and Generator Operator should not be revised, because every Generator Owner and Generator Operator may not own and operate a Generator Interconnection Facility, as the revised definitions imply. The revised definition of Generator Operator also adds a coordination requirement which is more properly included in the requirements of a standard.</li> <li>o While we are sensitive to the fact that this SAR is attempting to close a reliability gap, we believe that the definition of</li> </ul>

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Organization	Yes or No	Question 3 Comment
		<p>Generator Interconnection Facility is too broad. The Standard Drafting Team should consider limiting it to the voltages defined for the Bulk Electric System, and other facilities as deemed critical by the Regional Entity. Also, how does the Regional Entity deem a facility “critical”?</p> <p>o The Right-of-Way (ROW) definition should spell out TO and GO. Suggested rewording: “A corridor of land on which electric lines may be located. The Transmission Owner or Generator Owner which owns the lines may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain the lines.”</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
<p>Public Utility District #1 of Clark County</p>	<p>No</p>	<p>Clark Public Utilities believes the proposed definitions do not provide the necessary amount of guidance and clarity. The proposed definitions and standards revisions are being considered because of the potential impacts of a 26-mile 500 kV Generation Interconnection Facility. The proposed definition for the term “Generation Interconnection Facility” will include the 26- mile interconnection as well as a host of other types of interconnections that should not be considered in this effort. Clark’s generator is attached to the transmission grid by slack span (less than 100’) between the high side of the GSU (owned by the generator) and a circuit breaker (owned and operated by the Transmission Operator) located within the Transmission Operators switchstation. There are no operable components in the slack span. Clark believes the currently proposed standards actions are overly broad. The definitions and applicability of these standards must be narrowed. Clark proposes the following definition for Generator Interconnection Facility: Generator Interconnection Facility Sole-use facility for the purpose of connecting the generating unit(s) to the transmission grid. In this regard, the sole-use facility only transmits power associated with the interconnecting generator, whether delivered to the grid or delivered to the generator for station service or auxiliary load, or delivered to meet cogeneration load requirements. Generator Interconnection Facilities shall not include lines that are less than or equal to two spans in length or lines that the host Transmission Operator has agreed to include as part of the transmission system it operates.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
<p>Kansas City Power &amp; Light</p>	<p>No</p>	<p>I believe the intent of what has been proposed here is to define the term, “Generator Operator” to mean the Operator that operates units directly at a power station. With that in mind, although the proposed definition is close, I believe the interaction with the Transmission Operator only in the definition makes this confusing. Recommend consideration of the following definition: The entity that operates generating unit(s) and the Generator Interconnection Facility and performs the functions of supplying energy and reactive power as directed by the Balancing Authority and the Transmission Operator. The Generator Operator may also operate the Generator Interconnection Facility and is responsible for coordinating with the Balancing Authority and the Transmission Operator when the facility is energized or about to be energized to/de-energized from the transmission system. In addition, recommend adding the generating station property line to the definition for Generator Interconnection Facility for clarity: Sole-use facility that leaves generator property line for the purpose of connecting the generating unit(s) to the transmission grid. In this regard, the sole-use facility only transmits power</p>

**Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07**

Organization	Yes or No	Question 3 Comment
		associated with the interconnecting generator, whether delivered to the grid or delivered to the generator for station service or auxiliary load, or delivered to meet cogeneration load requirements.
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		
American Electric Power	No	It is unclear if the Generator Interconnection Facility definition only includes facilities at 100 kV or greater or those deemed critical to the Bulk Electric System by the Regional Entity.
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		
North Carolina Electric Membership Corporation	No	<p>NCEMC seeks clarification from the ad hoc team regarding the definition of Generation Interconnection Facility (GIF), especially regarding the option for ownership of the GIF. The way the definition currently reads leaves the interpretation that it might be optional for the Generator Operator to own the GIF. We are not sure that the Ad Hoc team intended this possible conclusion, which in our opinion, could completely change the scope of this SAR (in the case where the GOP does NOT own the GIF). If that is the intent of the Ad Hoc team or SDT, then the definition of Generator Operator should be changed to reflect the "option" of the GOP owning the GIF versus someone else like the Transmission Owner/Operator. Also, the second sentence of the GOP definition is not needed in our opinion since it is a requirement of the standards and as such requirements are not usually a part of the NERC definition.</p> <p>Other definitions we suggest changing are as follows:Vegetation Inspection - The systematic examination of a Right-of-Way to document vegetation conditions. The main reason for the change in definition for ROW was the proposed use of the non-capitalized term "electric line". Since the use of that phrase sometimes means distribution lines as well as transmission, we suggest staying with the capitalized NERC terms for better clarity.Right-of-Way (ROW) - A corridor of land on which a Transmission Line or Generator Interconnection Facility may be located. The owner of the Transmission Line or Generator Interconnection Facility may own the land in fee, own an easement, or have certain franchise,prescription, or license rights to construct and maintain lines.</p>
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		
Prairie Power, Inc.	No	PPI agrees with the first and existing sentence of the Generator Operator definition. However, the first part of the second sentence regarding operating the Generator Interconnection Facility is redundant with the first sentence. The second portion of the second sentence regarding coordinating with the Transmission Operator has been established already in TOP-001 R7.1 and TOP-003 R1.1 for the purpose of this project.
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		

Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07

Organization	Yes or No	Question 3 Comment
California ISO	No	<p>The definition for “Generator Interconnection Facility” (GIF) is not consistent with either Conclusion #1 of the Adhoc Group’s final report, or with “Applicability 4.5” added under FAC-003-1. Conclusion #1 mentions “Generator Interconnecting Facilities operating at a voltage of 100 kV or greater or those deemed critical to the Bulk Electric System by the Regional Entity...” and Applicability 4.5 mentions “Generator Interconnection Facility above 200 kV... or are otherwise deemed critical by the Regional entity below 200 kV...”. In both these instances it appears that the Adhoc Group is emphasizing those Generator Interconnection Facilities that are either part of the Bulk Electric System (BES) or deemed critical by the Regional entity. Therefore, we suggest modifying the definition as follows:First sentence, after the word grid, add “above 200 kV or otherwise deemed critical by the Regional entity below 200 kV”.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
Manitoba Hydro	No	<p>The definition for Generator Interconnection Facility does not fully include the recommendations of the Ad Hoc Group Conclusions. The first conclusion states that the facility must be 100 KV and above and more importantly that if there is power flows through this station that do not belong to the generators or their exclusive station loads, then this station becomes a TO responsibility.The definition of Transmission somewhat covers the above statement, but still need clarity.Example:Transmission - An interconnected group of lines and associated equipment in which network powerflows through this station are associated with the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems. Generator Interconnection Facility will not contain any of the above criteria.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
Constellation Power Source Generation Inc.	No	<p>The term “point of interconnection” must be used in the glossary definitions of a “Generator Interconnection Facility” and “Generator Interconnection Operational Interface.” It is a common industry term that is widely understood, and is even being used in the revision to FAC-008. Using the term “point of interconnection” would further clarify the new glossary definitions. Here are the proposed changes:Generator Interconnection Facility (NEW)Sole-use facility for the purpose of connecting the generating unit(s) to the transmission grid. In this regard, the sole-use facility only transmits power associated with the interconnecting generator, whether delivered to the grid or delivered to the generator for station service or auxiliary load, or delivered to meet cogeneration load requirements.The Generator Interconnection Facility is physically defined as the facility and its encompassing equipment beginning at the low side of the Generator Step Up to the point of interconnection. Generators connected to the same interconnection facility with different Generator Operators must coordinate operations. Generator Interconnection Operational Interface (NEW)Location at which operating responsibility for the Generator Interconnection Facility changes between the Transmission Operator and the Generator Operator.This location is known as the point of interconnection.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Because of potential confusion with language in various interconnection agreements, the SAR DT will</p>		

Organization	Yes or No	Question 3 Comment
not make changes to this definition and will defer to the SDT.		
Midwest ISO Standards Collaborators	No	We agree with the first sentence of the definition of Generator Operator. However, the first part of the second sentence regarding operating the Generator Interconnection Facility is redundant with the first sentence. The second portion of the second sentence regarding coordinating with the Transmission Operator is a requirement and already established in requirement X.
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		
First Wind	No	<p>We recommend the definition of Generator Interconnection Facility be modified.</p> <p>”Generator Interconnection Facility (NEW)A facility used for the sole purpose of connecting the generating unit(s) to the transmission grid. In this regard, the sole-use facility only transmits power associated with the interconnecting generator(s), whether delivered to the grid or delivered to the generator(s) for station service or auxiliary load, or delivered to meet cogeneration load requirements.</p> <p>The purpose of the above modification is to account for the situations where a Generator Operator may have many units, such as wind turbines, all using the same Generator Interconnection Facility to connect to the transmission grid. Additionally, we feel it is irrelevant if the Generating Unit is owned by one or the same owners. Two scenarios explain why multiple generators using the same Generator Interconnection Facility does not serve a function of a TO or TOP.</p> <ul style="list-style-type: none"> <li>• Scenario 1Each Generator Operator is connected to the Transmission Operator through an independent Generator Interconnection Facility. There is no need for the Generator Operators to coordinate their operations with one another because their operations do not impact common facilities. However, there may be a need for the Transmission Operator to coordinate its instructions to the Generator Operators (if they issue voltage schedules, for example). When it becomes necessary for the Transmission Operator to communicate instructions to the Generator Operators, it is necessary for the Transmission Operator to communicate with each of the Generator Operators.</li> <li>• Scenario 2Generator Operator A is connected independently, but Generator Operators B and C share a common Generator Interconnection Facility. In this case, it is necessary for Generators B and C to coordinate their operations. It is not necessary to designate either GO_B or GO_C as the “operator” of the Generator Interconnections Facility. Rather, it is most appropriate to place the obligation to coordinate operations on both parties. By placing the obligation on both parties, they share an equal burden to comply with the applicable standards.Placing the obligation to coordinate operations on both GO_B and GO_C does not increase the burden to the Transmission Operator.</li> </ul> <p>If there is trouble at the point of interconnect substation, the Transmission Operator might need to coordinate operations with GO_A, GO_B and GO_C in either Scenario 1 or Scenario 2. If in Scenario 2, the Transmission Operator only issued</p>

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Organization	Yes or No	Question 3 Comment
		<p>instructions to GO_A and GO_B, they could not be sure that GO_C would receive the instructions. Furthermore, since GO_B is not a Transmission Operator, they lack the authority to issue instructions to GO_C.</p> <p>We recommend an additional requirement to resolve coordination between generators. For example “Generator Operators interconnected through a common Generator Interconnection Facility shall coordinate their operations.”</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
<p>SERC Planning Standards Subcommittee</p>	<p>No</p>	<p>We suggest 3 alternate modified definitions:</p> <p>Right-of-Way (ROW)A corridor of land on which a Transmission Line or Generator Interconnection Facility may be located. The owner of the Transmission Line or Generator Interconnection Facility may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.</p> <p>Vegetation InspectionThe systematic examination of a Right-of-Way to document vegetation conditions.The main reason for the change in definition for ROW was the proposed use of the non-capitalized term "electric line". Since the use of that phrase sometimes means distribution lines as well as transmission, we suggest staying with the capitalized NERC terms for better clarity.</p> <p>Generator OperatorThe entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services. The Generator Operator may also operate the Generator Interconnection Facility. The main reason for the change in the definition for Generator Operator was that the 2nd sentence in the proposed definition was a requirement and not a true definition. The other change was to allow for the case where the Generator Operator was not the operator of the Generator Interconnection Facility.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
<p>AmerenUE, Power Operations Services</p>	<p>Yes</p>	
<p>American Transmission Company</p>	<p>Yes</p>	
<p>Bonneville Power Administration</p>	<p>Yes</p>	

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Organization	Yes or No	Question 3 Comment
Detroit Edison Company	Yes	
El Dorado Energy LLC	Yes	
Electric Market Policy	Yes	
Entegra Power Group LLC	Yes	
Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners	Yes	
Florida Municipal Power Agency	Yes	
Ingleside Cogeneration, LP	Yes	
Mesquite Power	Yes	
PSEG Companies	Yes	
Sempra Generation	Yes	
South Carolina Electric and Gas	Yes	
Tenaska, Inc.	Yes	



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Organization	Yes or No	Question 3 Comment
Pepco Holdings, Inc - Affiliates	Yes	<p>“Generator Interconnection Facility” is useful to allow GOs to be distinguished from TOs and their responsibilities. “Generator Interconnection Operational Interface” is also known as the “Point of Interconnect” by the RTO. This may be an alternate name that could be used to make things standard.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Because of potential confusion with language in various interconnection agreements, the SAR DT will not make changes to this definition and will defer to the SDT.</p>		
Southern California Edison co.	Yes	<p>Additional clarification would be useful as it/ they would cut down on future requests for interpretation... i.e provide a specific threshold for the proposed Generator interconnection Facility definition</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT.</p>		
Energy Standards Working Group	Yes	<p>In particular we support the revised definition of the Generator Interconnection Facility, which has appropriately incorporated our comments from the draft of the Team’s report</p>
<p><b>Response:</b> The SAR DT thanks you for your comment.</p>		

**4. Do you agree with the proposed *new* requirements intended to add clarity around expectations for generator owners and operators at the transmission interface?**

**Summary Consideration:** A number of responses expressed concern about the need for various proposed new requirements. An in-depth review of the comments, however, indicated that most of the concerns could be addressed by the SDT. As a result, many of these comments will be referred to the SDT for their consideration, including final resolution of which standards need to be modified. Revisions to the SAR also allow the SDT the option of merging the changes into one new standard or an existing standard(s).

Organization	Yes or No	Question 4 Comment
Kansas City Power & Light	No	<ul style="list-style-type: none"> <li>o PER-001, R1: The language proposed for PER-001, R1, infers the Generator Operator is able to take independent actions regarding the “Generation Facility” and the Generator Interconnection Facility. There is no definition for Generation Facility in this proposal or currently in the NERC Glossary. At any rate, do not agree with the Generator Operator taking any independent actions other than those to monitor and maintain the safe operation of a generating unit for the production of energy and reactive power.</li> <li>o PER-002, R3 (Proposed here): This infers again the Generator Operator taking independent actions with regard to equipment within the Generator Interconnection Facility. Although, the Generation Interconnection Facility is defined properly, that does not mean the Generator Operator is the control authority over that equipment. It is not uncommon for the Generator Operator to operate equipment within the Generator Interconnection Facility at the direction of the Transmission Operator. Recommend consideration be given to modify this requirement to reflect that.</li> <li>o TOP-001, R9 and R10 (Proposed here): This infers again the Generator Operator taking independent actions with regard to equipment within the Generator Interconnection Facility. Although, the Generation Interconnection Facility is defined properly, that does not mean the Generator Operator is the control authority over that equipment. It is not uncommon for the Generator Operator to operate equipment within the Generator Interconnection Facility at the direction of the Transmission Operator. Recommend consideration be given to modify these requirements to reflect the Transmission Operator can be the authority over the equipment within the Generation Interconnection Facility but that the Generator Operator may operate that equipment at the direction of the Transmission Operator.</li> </ul>
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		
American Electric Power	No	AEP believes that the only new requirement that should be addressed is in reference to FAC-003. AEP does not see benefit in expanding the scope of EOP-003, PER-001, and PER-002. With respect to TOP-004, AEP does not feel the added requirement is necessary as the Generator Interconnection Facility should be adequately sized to handle the output of the generator. The added requirement in TOP-008 for notification is redundant with other obligations for the GOP to notify other entities, such as in COM-002 and TOP-003.

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Organization	Yes or No	Question 4 Comment
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
<p>American Transmission Company</p>	<p>No</p>	<p>Clarify the definition of generator interconnection facility to include who this applies to as shown in the conclusions above in #3. A Generator Interconnection Facility is considered as though part of the generating facility specifically for purposes of applying Reliability Standards to a Generator Owner or Generator Operator.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
<p>E.ON U.S.</p>	<p>No</p>	<p>E.ON U.S. has already determined a Division of Responsibilities between the GO/TO and therefore does not see the need for auditable reliability standards to be added between the GO/TO. Also, it is not necessary to include the phrase “including the Generator Interconnection Facility” in all the applicable requirements. Since the term Generator Interconnection Facility is proposed to be included in the Glossary definitions for Generator Operator, then it would be redundant to also add the phrase throughout the applicable standards.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT.</p>		
<p>Public Utility District #1 of Clark County</p>	<p>No</p>	<p>Many of the new requirements place excessive demands on generators that do not increase system reliability.</p> <p>In EOP-003 Generator Operators are added to the applicability and as a result R7 is a newly applicable requirement to Generator Operators. However, this requirement now implies that Generator Operators are required to engage in the coordination efforts (with the BA and TOP) of automatic underfrequency load shedding. Generators do not have the option of determining what levels of frequency to ride through and what levels of frequency to trip on. Those quantities are defined by the RC and the BA and Generator Operators are required to have generator protection system settings that allow this ride through. Generators should have frequency and voltage ride through requirements that are coordinated with automatic load shedding programs by the RC, BA and/or TOP but should simply be required to comply with these requirements and should not have a role in the coordination. The comments in the GOTO Final report indicate that this addition is required to ensure that a generator frequency trip set point is appropriately included in the currently required coordination between the BA and TOP. Clark believes that generators should not participate in the coordination but simply be required to comply with frequency ride through requirements dictated by the RC, BA and/or TOP.</p> <p>Clark believes that FAC-002 clearly applies to Generator Owners and this standard requires that generator integration facilities address reliability impacts in the interconnected transmission system. Additionally, the proposed change to EOP-003 appears to have nothing to do with the issue at hand (i.e. removal of TOP status to a generator because of a Generator Interconnection Facility).</p> <p>Clark believes it is inappropriate to make EOP-003 applicable to Generator Operators and to imply that a Generator</p>

Organization	Yes or No	Question 4 Comment
		<p>Operator has any participation in coordination of underfrequency load shedding other than to comply with frequency ride through requirements of the RC, BA and/or TOP.</p> <p>Clark agrees that the changes to FAC-003 are appropriate, will lead to increased reliability and do not result in unnecessary reporting or paperwork. The applicability section clearly limits the scope of what Generation Interconnection Facilities would be included in this standard by having a “two span” limit in the length of the facility. This limit appropriately will exclude those generators that have arranged for a Transmission switchstation owned and operated by a Transmission Operator located immediately adjacent to the generator.</p> <p>In IRO-005, R13, the standard proposes to require a Generator Operator to immediately inform the TOP of status changes to SPS. While Clark is not opposed to this change, it is unclear why the issue at hand (i.e. removal of TOP status to a generator because of a Generator Interconnection Facility) has led to this addition. The SAR implies that the industry need leading to the SAR is the “registration of Generator Owners and Generator Operators as Transmission Owners and Transmission Operators, based on the facilities that connect the generators to the interconnected grid.” IRO-005, R13 does not appear to have any connection to this industry need.</p> <p>In PER-001, Generator Operators are added to the applicability and as a result of the new R2 Generator Operators will be required to demonstrate the authority of operating personnel over Generation Facilities and Generation Interconnection Facilities. This level of authority is unnecessary. Transmission Operators already have this authority (refer to PER-001, R1). Generator Operators are already required to comply with reliability directives issued by RCs, BAs, and TOPs in other reliability standards. The requirement to demonstrate that a generator needs this authority over its generating facility is unnecessary and has no connection with the industry need the SAR is based on. A generator operator has authority over its generator by virtue of its registration as a Generator Operator. The need for further proof that a GOP can operate generation facilities for which it is a registered GOP has not been demonstrated. The requirement to demonstrate that a generator needs authority over a Generation Interconnection Facility is; for the same reason, unnecessary. A generator operator has authority over its generator by virtue of its registration as a Generator Operator for that facility. The need for further proof that a GOP can operate Generation Interconnection Facilities for which it is a registered GOP has not been demonstrated.</p> <p>In PER-002, Generator Operators are added to the applicability and as a result of the new R3 Generator Operators will be required to demonstrate training programs similar to TOP training requirements. Clark is not opposed to training its GOP personnel; however, including the training program within the PER-002 training requirements elevates this training to a level that has not been demonstrated to be necessary in all cases. Currently, this requirement is applicable to a TOP. By removing the TOP classification to certain GO/GOP registered entities that are only a TOP by virtue of Generation Interconnection Facilities, the potential exists that inadequately trained personnel may be directing the operation of a Generation Interconnection Facility. However, as stated earlier, when the Generation Interconnection Facility is short in length and more importantly when this facility has no devices which can be operated (i.e. direct connection between the generator step-up transformer or generator protection circuit breaker (owned or</p>

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Organization	Yes or No	Question 4 Comment
		<p>operated by the GOP) and the TOP owned and operated transmission breaker) there is no gap in having adequately trained personnel operating transmission facilities. Clark believes the applicability section should include minimal limits for applicable Generation Interconnection Facilities or that the definition of Generation Interconnection Facilities should be amended such that PER-002 applicability is limited to GOPs that own facilities that are similar in nature to the New Harquahala Generation Interconnection Facilities that have led to this SAR.</p> <p>The proposed changes to TOP-004 are confusing. The proposal does not add GOP in the applicability section but the newly proposed R7 appears to obligate GOPs. The requirement should be revised to obligate a TOP to ensure that a GOP operates within its applicable limits. These limits should have already been established.</p> <p>In FAC-008 Transmission Owners and Generator Owners are required to have a ratings methodology.</p> <p>In FAC-009 TOs and GOs are required to calculate facility ratings. In both of these standards, documentation is to be made available to RCs, TOPs, PAs and TPs that have responsibility. At the very least, the applicability section of a standard should be coordinated with the entities having obligations due to the requirements of a standard.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.)</p>		
Luminant	No	<p>No, for the bulk of the Generator Owners whose Generation Interconnection Facilities (GIF) are connected in close proximity (i.e., one-half mile or less) to the BES, the requirements will only add additional unduly burdensome documentation, paperwork and compliance risk, with no reliability benefit</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
Independent Electricity System Operator	No	<p>Please see our comments under Q5 where we comment on both the additions and modifications to the standards.</p>
ISO RTO Council Standards Review Committee	No	<p>Please see our comments under Q5 where we comment on both the additions and modifications to the standards.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
Prairie Power, Inc.	No	<p>PPI considers the phrase “for SPS relay or control equipment under its control” to be confusing and ambiguous in the new requirement IRO-005 R13. We suggest deletion of this phrase maintains the intent of the requirement and removes the unclear reference to the subject associated with the word “its”.</p>

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Organization	Yes or No	Question 4 Comment
		<p>PPI questions why the sub-elements of new requirement TOP-001 R9 are stipulated in bullet item format rather than sub-requirement format.</p> <p>PPI agrees with the first portion of new requirement PER-001 R2. Regarding the second portion of new PER-001 R2, the Generator Operator is already required to comply with Reliability Coordinator directives as established in IRO-001 R8 and TOP-001 R3, and further the Generator Operator is already required to comply with Transmission Operator directives also as established in TOP-001 R3. PPI does not see any benefit in reiterating the Generator Operator responsibility and authority to follow directives in this new requirement. PPI would suggest stipulating the Generator Operator be responsible for following directives of the Balancing Authority in a separate Requirement or sub-requirement, and not lumped into this new requirement.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT. The bulleted items in TOP-001 R9 should have been numbered. We'll pass this comment on to the SDT.</p>		
Duke Energy	No	See detailed comments under Question 5 below.
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
AmerenUE, Power Operations Services	No	See response to Item #2.
<p><b>Response:</b> The SAR DT thanks you for your comment. The SAR has been modified to allow the SDT the option of merging the changes into one new standard or an existing standard(s).</p>		
Midwest ISO Standards Collaborators	No	The requirement additions to the TOP standards parallel requirements that the Real-Time Operations standards drafting team has already proposed for removal. This project needs to be coordinated with the Real-Time Operations project.
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
Tenaska, Inc.	No	TOP-001 R10 should be amended such that the proposed R10 reads as follows: The Transmission Operator shall have decision-making authority over operation of the Generator Interconnection Operational Interface at all times in order to preserve interconnection reliability, unless by exercising that authority such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability

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Organization	Yes or No	Question 4 Comment
		Coordinator or Transmission Operator can implement alternate remedial actions.
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		
North Carolina Electric Membership Corporation	No	<p>We agree with most of the new requirements with the exception of two:</p> <p>1) New requirement R9 of TOP-001 appears to be very similar to existing requirements of TOP-001 (req R7) and TOP-003 (req R1). Further clarification is needed to distinguish the differences between this new requirement and existing requirements.</p> <p>2) New requirement R5 of TOP-008 directs the GOP to disconnect the GIF when “safety is jeopardized” or... which triggers the immediate question: Who’s safety does the Ad Hoc group refer to, the personnel of the GO/GOP or the safety of the transmission system or its personnel or both possibly? Please clarify. If it the safety of the transmission, its personnel or the system grid in general, then why would it not be the TOP's responsibility to provide a directive of this nature since the TOP would have a greater perspective/visibility than the GO/GOP of the system operating conditions in real time?</p>
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		
Energy Standards Working Group	No	<p>We are supportive of most of the new requirements being suggested with the following two exceptions:</p> <p>IRO-005 R13 which states:R13. The Generator Operator shall immediately inform the Transmission Operator of the status ofthe Special Protection System, including any degradation or potential failure to operate as expected for SPS relay or control equipment under its control.We believe that this proposed additional requirement is redundant as it is already covered by the requirements of PRC-001-1</p> <p>ANDTOP-001 R10 which states:The Transmission Operator shall have decision-making authority over operation of theGenerator Interconnection Operational Interface at all times in order to preserveInterconnection reliability.</p> <p>We would amend the proposed R10 as follows: The Transmission Operator shall have decision-making authority over operation of the Generator Interconnection Operational Interface at all times in order to preserve interconnection reliability, unless by exercising that authority such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.</p>
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		

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Organization	Yes or No	Question 4 Comment
Electric Market Policy	No	We feel it is not necessary to include the phrase “including the Generator Interconnection Facility” in all the applicable requirements. The term Generator Interconnection Facility is proposed to be included in the Glossary definitions and the proposed definition of Generator Operator includes the following language “also operates the Generator Interconnection Facility and is responsible for coordinating with the Transmission Operator when the facility is energized or about to be energized to/de-energized from the transmission system” which we feel is sufficient and superior to having the phrase repeated throughout the applicable standards.
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		
First Wind	No	We feel it is not necessary to include the phrase “including the Generator Interconnection Facility” in all the applicable requirements. The term Generator Interconnection Facility is proposed to be included in the Glossary definitions and the proposed definition of Generator Operator includes the following language “also operates the Generator Interconnection Facility and is responsible for coordinating with the Transmission Operator when the facility is energized or about to be energized to/de-energized from the transmission system” which we feel is sufficient and superior to having the phrase repeated throughout the applicable standards.
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		
California ISO	Yes	
Competitive Power Ventures, Inc.	Yes	
El Dorado Energy LLC	Yes	
Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners	Yes	
Florida Municipal Power Agency	Yes	
Ingleside Cogeneration,	Yes	



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Organization	Yes or No	Question 4 Comment
LP		
Manitoba Hydro	Yes	
Mesquite Power	Yes	
PSEG Companies	Yes	
Sempra Generation	Yes	
SERC Planning Standards Subcommittee	Yes	
South Carolina Electric and Gas	Yes	
Southern California Edison co.	Yes	Additional clarification would be useful as it/ they would cut down on future requests for interpretation.
<b>Response:</b> The SAR DT thanks you for your comment.		
Pepco Holdings, Inc - Affiliates	Yes	Application of FAC-003 for Gen Interconnect Facilities that are "two spans, generally 1/2 mile or more past the property line" is reasonable as long as the "property line" remains in the definition. OK.
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		
Constellation Power Source Generation Inc.	Yes	Constellation agrees with the proposed new requirements in principal. However, further clarity is needed in the requirements so that there isn't any added confusion. Either an implementation plan or a "frequently asked questions" document would be recommended.
<b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.		
Bonneville Power Administration	Yes	However, believe there is a problem with #8 referring to TOP-008. The solution to the generator facility line overload may be a transmission system problem so the Generator should not disconnect unless the TOP directs it to do

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Organization	Yes or No	Question 4 Comment
		so(confer unless a safety issue). Also, TOP-001 needs careful work. The transmission system doesn't want environmental issues turning off generators during emergency or critical transmission conditions.
Entegra Power Group LLC	Yes	SEE COMMENTS FOR QUESTION 2.
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		

**5. Do you agree with the proposed *modified* requirements intended to add clarity around expectations for generator owners and operators at the transmission interface?**

**Summary Consideration:** A number of responses expressed concern about the proposed modifications. An in-depth review of the comments indicated that most of the concerns could be addressed by the SDT during the standards drafting process. Based on discussions with FERC and NERC staffs regarding previous Commission actions and NERC compliance filings, the SAR DT modified the SAR to give the SDT the flexibility to consider further modifications not identified in the Ad Hoc Report.

Organization	Yes or No	Question 5 Comment
Independent Electricity System Operator		<p>(1) We realize that the SDT needs to make changes to “approved standards” but there are a number of standards involved in this project whose newer versions have either received the BoT approval, or about to be adopted by the BoT or at the stage of being finalized or balloted. To make changes to the soon to be outdated versions is confusion and will require a subsequent change when FERC approves the standards. We therefore suggest the SDT to also mark up those which have newer versions already or soon to be adopted by the BoT and those that are being balloted. Alternatively, the SDT may want to post the changes to those FERC approved standards only, and defer actions on those that have not been approved by FERC and those that are being revised/balloted until FERC approves them.</p> <p>(2) EOP-001: R7.3 has been changed to add the term “..., including outages to the Generator Interconnection Facility, to maximize .....”. It is not clear whom the TOP and the BA should coordinate with and it does not place a requirement on the entity that is responsible for the Generator Interconnection Facility outage planning and scheduling. We suggest to add the appropriate responsible entity (Generator Owner?) to the Applicability Section, and add this entity to R7.3.</p> <p>(3) In EOP-008 R1.3, is it the intent of the revised requirement that the plan address monitoring and control of ALL Generator Interconnection Operational Interface[s] or just the critical ones (as with the critical transmission facilities)?</p> <p>(4) R10 of TOP-001 is not written in the form of a requirement. We suggest replacing “have” with “exercise”. Thus, the requirement would read “The Transmission Operator shall exercise decision-making authority over operation of the Generator Interconnection Operational Interface...”</p> <p>(5) TOP-004: The Applicability Section needs to be revised to add Generator Operator to reflect the new requirement R7. We also suggest the SDT to evaluate if there is an alternative or more suitable place for this requirement than the TOP standard.</p> <p>(6) A number of standards are missing their VSLs. Most VSLs have similar wording in the requirements so many of them will need to be revised to reflect changes to the requirements proposed in this project.</p>

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Organization	Yes or No	Question 5 Comment
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT. The redlines were only intended to provide stakeholders with an idea of the proposed scope of changes – the team recognizes that any new/revised requirement may result in associated changes to the VRFs, Time Horizons, VSLs, data retention, measures, etc.</p>		
<p>Energy Standards Working Group</p>	<p>No</p>	<p>Comments: see my note re FAC-003</p> <p>We are supportive of the modified requirements being suggested with the following exception:</p> <p>FAC-003:We offer the following suggested changes for greater clarity.</p> <p>4. Applicability:Replace the proposed sections 4.4 and 4.5 with the following:4.4. Generator Owner that owns a Generator Interconnection Facility above 200 kV that exceed two spans from the generator property line or are below 200 kV and deemed critical to the reliability of the electric system by the Regional Entity (subject to the two-span criteria.)</p> <p>Furthermore, the Standard Drafting Team should insure that in drafting the requirements and subsequent sections of the standards, it is clear that the use of the words “Generator Owner” refers only to the subset of Generator Owners as specified by section 4.4, not to all Generator Owners included in the NERC Registry.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
<p>Constellation Power Source Generation Inc.</p>	<p>No</p>	<p>Constellation agrees with the proposed changes for BAL-5, EOP-1, EOP-4, EOP-8, FAC-1, FAC-8, FAC-9, IRO-5, MOD-10, MOD-12, PER-1, PRC-1, PRC-5, TOP-1, TOP-2, TOP-3, VAR-1, and VAR-2. Furthermore, the changes made to CIP-2 are especially valuable in that the clarity it brings with the added terminology would assist in identifying individual assets.</p> <p>Constellation does not agree with (or has comments for) the proposed changes to:</p> <ul style="list-style-type: none"> <li>oEOP-3 - GOs/GOPs should not be included in this standard</li> <li>oFAC-3 - Constellation agrees in principal with this change, but further work is needed in regards to which GOs fall into this category. The wording may be changed to “two or more spans exceeding ½ mile in total length,” but further discussions is needed on this topic.</li> <li>oPER-2 - Constellation agrees in principal with this change, but believes that this requirement should be combined into PRC-001 R1, and eliminate the redundancy.</li> <li>oPRC-5 - Testing of the Protection System of the Generator Interconnection Facility is not always the sole responsibility of the GO. Some verbiage attesting to that is needed. Otherwise, it is wise to include the Generator Interconnection Facility into this standard so that no gap may exist in the testing of a Protection System that may impact the BES.</li> </ul>

Organization	Yes or No	Question 5 Comment
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
E.ON U.S.	No	E.ON U.S. has already determined a Division of Responsibilities between the GO/TO and therefore does not see the need for auditable reliability standards to be added between the GO/TO.
<p><b>Response:</b> The SAR DT thanks you for your comment. Based on a review of the full body of industry comments, we believe that there is a reliability need for this SAR.</p>		
Duke Energy	No	<ul style="list-style-type: none"> <li>o General Comment - The Standards Drafting Team (SDT) will need to make sure that Measures are developed or modified to correspond to new or revised requirements of the standards.</li> <li>o Process Question - Will the SDT fold these standards revisions into other projects, or will new versions be created as part of this project?</li> <li>o FAC-003-1 - Applicability sections 4.4 and 4.5 should be combined to make it clear that the standard only applies to the Generator Owner’s GIF. Does the 2-span limit mean that there are three towers? What criteria will the Regional Entity use to deem a GIF critical? The language about the generator property line is confusing - how does it compare to the Right-of-Way (ROW) definition? In some cases the TO may own the ROW, while the GO owns the GIF.</li> <li>o FAC-008-1 - Requirement R1 raises a question regarding whether a GIF can be jointly owned by a TO and a GO. If a TO is an owner, then the GIF is not a GIF but a transmission facility, right?</li> <li>o FAC-009-1 - We don’t think revisions are needed to R1 and R2, since the term “Facilities” already implicitly includes GIF. If you don’t agree, then perhaps a more straightforward approach would be to revise the definition of “Facility” to explicitly include the GIF.</li> <li>o IRO-005-2 - We think that you don’t need to specifically add the GIF to R9 because it would have to already be included in the requirement as part of any generation outage coordination. Under R13 we would change “the Special Protection System” to “any Special Protection System”. We also note that this new R13 propagates the poor language of R12 (i.e., how does anyone define “a potential failure to operate”?).</li> <li>o PER-001-0 - Applicability section 4.3 should be expanded to make it clear that Requirement R2 only applies to the Generator Operator with respect to the GIF, and R2 should be likewise revised. The GOP is already obligated under TOP-001-1 Requirement R3 to comply with RC and TOP directives unless such actions would violate safety, equipment, regulatory or statutory requirements. Suggested rewording of Applicability section 4.3 : “Generator Operators -This standard shall apply to Generator Operators who own a Generator Interconnection Facility.” Suggested rewording of Requirement R2 : “For Generation Facility Interconnection equipment under their direct control, each Generator Operator shall provide operating personnel with the responsibility and authority to implement real-time actions and to follow reliability</li> </ul>

Organization	Yes or No	Question 5 Comment
		<p>directives of Reliability Authorities, Transmission Operators and Balancing Authorities, to ensure the stable and reliable operation of the Generation Interconnection Facility.”</p> <ul style="list-style-type: none"> <li>o PER-002-0 - Applicability section 4.3 should be expanded to make it clear that Requirement R2 only applies to the Generator Operator with respect to the GIF. Suggested rewording of Applicability section 4.3 : “Generator Operators -This standard shall apply to Generator Operators who own a Generator Interconnection Facility.”</li> <li>o PRC-001-1 - Changes to PRC-001-1 should probably not be made right now, because it is already a vague standard, and was the subject of an Interpretation (Project 2009-30) which was voted down in February.</li> <li>o TOP-003-0 - Requirement R1 and its sub-requirements are poorly written. We suggest folding R1.3 into R1 with this suggested rewording: “Generator Operators and Transmission Operators shall provide planned outage information by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection, as follows : “</li> <li>o TOP-004-2 - We question whether Requirement R7 is appropriate, since by definition the GIF is not part of the transmission system network and does not fit with the Purpose statement of this standard. If R7 is retained, then you need to add Generator Operator to the Applicability section.</li> <li>o TOP-008-1 - Need to add GOPs to the Purpose statement.</li> </ul>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
California ISO	No	<p>Please see our comments under Question 2 above. In addition, with regard to the proposed change to Standard PRC-001, the California ISO (CAISO) questions the need for a BA to understand the purpose and limitations of protection schemes associated with all of the Generator Interconnection Facilities in its area given a BA’s role is to balance load/generation/interchange which does not require the BA to operate any generator or BES facilities, or to understand the characteristics or limitations of any equipment. Any potential loss of one or more generator due to protection or equipment issues will need to be communicated by the GO or GOP to the BA for consideration in reserve calculation</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
Prairie Power, Inc.	No	<p>PPI does not agree with the modification to EOP-003 R7. The Generator Operator does not have load to be shed, therefore none to be coordinated. If the drafting team is intending to require the Generator Operator to coordinate the underfrequency relay settings on their resources with load shedding plans established by the Transmission Operator and Balancing Authority, this is an appropriate requirement. The modification, though, does not accomplish this.PPI questions why the sustained line outages reported quarterly to the RRO pursuant to FAC-003 R3 by the Generator Owner, as modified, are not reported to NERC in Requirement 4 of the same Standard.</p>

Organization	Yes or No	Question 5 Comment
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
AmerenUE, Power Operations Services	No	See response to Item #2.
<p><b>Response:</b> The SAR DT thanks you for your comment. The SAR has been modified to allow the SDT the option of merging the changes into one new standard or an existing standard(s).</p>		
Luminant	No	<p>The following comments are specific to each standard</p> <p>CIP-002 - This standard is currently under revision and any change should be addressed by the Cyber Security Standards Revision Team.</p> <p>EOP-003 - Application of this reliability standard to a GOP is incorrect. The Generator Operator has no direct responsibility for load shedding. Only the TOP and BA have load shedding responsibility.</p> <p>EOP-004 - The inclusion of GIF in this reliability standard is redundant as the GOP has responsibility for all of its facilities, including any generators. . Since generation units are not independently identified with a particular GOP, the GIF does not need to be independently identified. Also, there is a NERC project currently underway to revise this standard (Project 2009-01).</p> <p>FAC-003 - Luminant agrees this standard should apply in those instances when the generator is connected to the BES through its GIF over a substantial distance. However, the applicability of this standard to a GIF needs to specify a distance (such as one-half (½) mile from the plant property boundary) not a number of spans since the spacing between spans can vary from extensively. Defining the applicability of this standard in terms of a number of spans will create inconsistency in the application of the requirements.</p> <p>IRO-005 - New requirement R13 presumes that a Special Protection System (SPS) is the sole responsibility of a GOP, which, in most cases, it is not. Most SPS are the responsibility of the TO, not the GOP. This requirement does not define which SPS is being monitored. A requirement of this nature should define an SPS on the GIF.</p> <p>PER-001 - The addition of a requirement applicable to GOP in this standard goes well beyond the scope of this project's purpose. A NERC Standards Drafting Team, under Project 2006-01, did not add any GOP requirements to the PER standards. This proposed GOP requirement is redundant. Current NERC Reliability Standard TOP-001, R3 requires Generator Operators to follow reliability directives, as does IRO-001, R8. This proposed requirement should be deleted. It adds paperwork, documentation and compliance risk with no reliability benefit. The PER-001 standards were intended for overall grid management, not the operation of a power plant.</p>

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Organization	Yes or No	Question 5 Comment
		<p>PER-002 - The recent NERC Standards Drafting Team, under Project 2006-01, specifically declined to make this standard applicable to GOP. In addition, the 2006-01 project is retiring this standard with the adoption of the revised PER-005.</p> <p>PRC-001 - The inclusion of Generator Interconnection Facility is redundant. However, there is a current NERC Drafting team revising PRC-001 and this issue should be referred to that team.</p> <p>PRC-005 - Any revisions to PRC-005 should be referred to the current PRC-005 drafting team.</p> <p>TOP-001 - Draft Requirements R9 and R10 are extremely broad. These should only apply to narrowly defined GIFs such as long span connections or GIFs with transmission load flowing through the GIF. Care should be taken in this requirement not to duplicate requirements such as coordination of outage planning. The requirements should be specific, and not fill in the blank for the TOP or region.</p> <p>TOP-004 - Draft Requirement R7 is redundant to requirements in other standards and is not needed.</p> <p>IRO-005-2, R13, and IRO-005-3, R10, require the GOP to operate the BES to its most limiting factor, which is, by definition, implicitly within its facility ratings.</p> <p>TOP-008 - Does draft requirement R5 fit in this standard that addresses IROL and SOL? This requirement should only apply to the same long connection GIF facilities identified in TOP-003.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
Florida Municipal Power Agency	No	<p>The modification of EOP-003-1, R7 is inconsistent with the requirement. The original requirement requires the BA and TOP to coordinate with others (presumably DPs, TOs and GOPs) in their area for various automatic action (e.g., UFLS, automatic tripping of cap banks, and frequency capabilities of generators for instance). The GOP has no “area” to coordinate and no one within its area to coordinate with. So, it is the BA and TOP that coordinate within their area, not the entities embedded within the BA or TOP area. Otherwise, we ought to add at a minimum DPs, LSEs, and TOs to the list.</p> <p>The modifications to EOP-004-1 R2; FAC-001-0 R1.1; FAC-008-1; FAC-009-1; MOD-010, MOD-012, PRC-001, PRC-004; PRC-005; TOP-001-1 R7; TOP-002 R3 and R18; TOP-003 R1 and R1.1; and VAR-002 R3.2 are redundant with no need to specifically call out the Generator Interconnection Facility. The interconnection facilities are facilities and already included in the term “on its system or facilities” and “generating facilities”, etc. And, the Generator Owner and Operator are already responsible for their interconnection facilities in the definition of those Entities. Specifically calling out the interconnection facilities calls into question why other facilities are not specifically called out.</p> <p>As discussed in the response to #2 above, addition of the Generator Owner to FAC-003 over-steps Federal Power Act Section 215 since radial transmission lines to generating plants will not participate in a cascading outage since the loading of radial facilities to power plants will not change significantly with outages on the interconnected system.</p>



Organization	Yes or No	Question 5 Comment
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
<p>North Carolina Electric Membership Corporation</p>	<p>No</p>	<p>We agree with most all of the modified requirements with one exception:                      For FAC-003, regarding the "two-span criteria" or "about 0.5 miles" test for generator applicability, we would like the ad hoc team to consider providing more direction or greater specificity that makes a GIF of two or less spans to become exempt, while one of greater than two spans (0.5 mile) but less than 5 spans (0.8 miles) to suddenly become subject to the FAC-003 standard requirements. The "generator's line-of sight" rule as described in response to item #3 in the Final Report in our opinion should be clearly specified in the FAC-003 proposed standard change at a minimum to avoid mis-interpretations. Also, regarding item #10 issue in the report, we would like the ad hoc team to consider proposing a 4th proposal which would be a hybrid between Proposal 2 and Proposal 3 as reported within the Final Report which would provide a "bright-line test" as to what generators are exempt or not to the FAC-003 standard, rather than solely relying on Proposal 2 which relies on the physical attributes of the GIF in ruling out generators subject to FAC-003. If the GIF is 3-4 spans or 0.53 miles in length, but still within the "line of sight" of the GOP, then allow the GOP working with the RE and TOP to rule out smaller generators that are immaterial to the reliability of the grid.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
<p>Tenaska, Inc.</p>	<p>No</p>	<p>We are supportive of the modified requirements being suggested with the following exception related to the suggested changes on FAC-003 for which we offer the following modification for greater clarity:                      4. Applicability: Replace the proposed sections 4.4 and 4.5 with the following:                      4.4. Generator Owner that owns a Generator Interconnection Facility above 200 kV that exceed two spans from the generator property line or are below 200 kV and deemed critical to the reliability of the electric system by the Regional Entity (subject to the two-span criteria.)                      Furthermore, the Standard Drafting Team should insure that in drafting the requirements and subsequent sections of the standards, it is clear that the use of the words "Generator Owner" refers only to the subset of Generator Owners as specified by section 4.4, not to all Generator Owners included in the NERC Registry.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
<p>Midwest ISO Standards Collaborators</p>	<p>No</p>	<p>We do not agree with the modification to EOP-003 R7. The Generator Operator does not have load shed to coordinate. We believe the drafting team is intending to require the Generator Operator to coordinate underfrequency relay settings on their generators with the BA and TOP load shedding plans. We agree this is appropriate but the modification does not</p>

Organization	Yes or No	Question 5 Comment
		<p>accomplish this.</p> <p>EOP-004 R2 seems to be modified unnecessarily. System and facilities are already included in the requirement and, thus, would include the Generator Interconnection Facility.</p> <p>We do not agree adding Generator Interconnection Operational Interface to R1.3 in EOP-008. The sub-requirement already requires the contingency plan to consider generation control which would require consideration of the Generator Interconnection Operational Interface. Furthermore, there is a lack of coordination with the project to update this standard. A newer, significantly modified version of this standard has already been through an initial ballot period.</p> <p>IRO-005 R9 modifications are not needed. The requirement already requires an RC to coordinate pending generation outages. This would have to include any outage such as the Generator Interconnection Facility. Many of the changes to the TOP standard are modifying requirements that the Real-Time Operations standards drafting team has already proposed for removal. This project needs to be coordinated with the Real-Time Operations project.</p> <p>VAR-001 R8 modifications are not necessary because the TOP is already required to operate reactive generation scheduling. They can't do this without considering the Generator Interconnection Facility.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
<p>ISO RTO Council Standards Review Committee</p>	<p>No</p>	<p>While we generally agree with the proposed wording change, we have a number of comments the first of which is a timing decision issue.</p> <p>(1) We realize that the SDT needs to make changes to “approved standards” but there are a number of standards involved in this project whose newer versions have either received the BoT approval, or about to be adopted by the BoT or at the stage of being finalized or balloted. To make changes to the soon to be outdated versions is confusing and will require a subsequent change when FERC approves the standards. We therefore suggest the SDT to coordinate their changes with the other drafting teams that are working on the newer versions already or soon to be adopted by the BoT and those that are being balloted. Alternatively, the SDT may want to post the changes to those FERC approved standards only, and defer actions on those that have not been approved by FERC and those that are being revised/balloted until FERC approves them.</p> <p>(2) EOP-001: R7.3 has been changed to add the term “..., including outages to the Generator Interconnection Facility, to maximize .....”. It is not clear with whom the TOP and the BA should coordinate with and it does not place a requirement on the entity that is responsible for the Generator Interconnection Facility outage planning and scheduling. We suggest removing the changes on this requirement all together. Generator maintenance will include the Generator Interconnection Facility. These are extra words that are not needed.</p> <p>(3) A number of standards are missing their VSLs. Most VSLs have similar wording in the requirements so many of them</p>

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Organization	Yes or No	Question 5 Comment
		<p>will need to be revised to reflect changes to the requirements proposed in this project.</p> <p>(4) We do not agree with the modification to EOP-003 R7. The Generator Operator does not have load shed to coordinate. We believe the drafting team is intending to require the Generator Operator to coordinate underfrequency relay settings on their generators with the BA and TOP load shedding plans. We agree this is appropriate but the modification does not accomplish this.</p> <p>(5) EOP-004 R2 seems to be modified unnecessarily. System and facilities are already included in the requirement and, thus, would include the Generator Interconnection Facility.</p> <p>(6) We do not agree adding Generator Interconnection Operational Interface to R1.3 in EOP-008. The sub-requirement already requires the contingency plan to consider generation control which would require consideration of the Generator Interconnection Operational Interface. Furthermore, there is a lack of coordination with the project to update this standard. A newer, significantly modified version of this standard has already been through an initial ballot period.</p> <p>(7) IRO-005 R9 modifications are not needed. The requirement already requires an RC to coordinate pending generation outages. This would have to include any outage such as the Generator Interconnection Facility.</p> <p>(8) PRC-001: We question the need for a BA to understand the purpose and limitations of protection schemes associated with all of the Generator Interconnection Facilities in its area given a BA's role is to balance load/generation/interchange which does not require the BA to operate any generator or BES facilities, or to understand the characteristics or limitations of any equipment. Any potential loss of one or more generator due to protection or equipment issues will need to be communicated by the GO or GOP to the BA for consideration in reserve calculation.</p> <p>(9) Many of the changes to the TOP standard are modifying or adding parallel requirements that the Real-Time Operations standards drafting team has already proposed for removal. This project needs to be coordinated with the Real-Time Operations project to assess the need for these additions/modifications.</p> <p>(10) VAR-001 R8 modifications are not necessary because the TOP is already required to operate reactive generation scheduling. They can't do this without considering the Generator Interconnection Facility.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. Several stakeholders had similar concerns, and all will be referred to the SDT.</p>		
Bonneville Power Administration	Yes	
Competitive Power Ventures, Inc.	Yes	

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Organization	Yes or No	Question 5 Comment
Detroit Edison Company	Yes	
El Dorado Energy LLC	Yes	
Electric Market Policy	Yes	
Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners	Yes	
First Wind	Yes	
Ingleside Cogeneration, LP	Yes	
Kansas City Power & Light	Yes	
Mesquite Power	Yes	
PSEG Companies	Yes	
Sempra Generation	Yes	
SERC Planning Standards Subcommittee	Yes	

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Organization	Yes or No	Question 5 Comment
South Carolina Electric and Gas	Yes	
Southern California Edison co.	Yes	Additional clarification would be useful as it/ they would cut down on future requests for interpretation
<b>Response:</b> The SAR DT thanks you for your comment.		
American Electric Power	Yes	AEP feels that a majority of the standards that were modified add clarity. We reserve the right to comment when the Standard Drafting Team posts the draft Standard(s).
<b>Response:</b> The SAR DT thanks you for your comment. There will be additional opportunities to comment on the specific proposed modifications when the project progresses to standard drafting.		
Public Utility District #1 of Clark County	Yes	Except as discussed in comments 2, 3, and 4, Clark is in agreement with the proposed changes.
<b>Response:</b> The SAR DT thanks you for your comment.		
American Transmission Company	Yes	<p>For FAC-009 [Establish and Communicate Facility Ratings], we believe that the additional wording to highlight that the term “Facilities” includes “Generation Interconnection Facilities” is superfluous, and therefore, it should not be added. The proposed new and revised definitions provide more than enough clarity</p> <p>For MOD-010 [Steady State Data for System Modeling], we believe that the additional wording of “for plant and Generator Interconnection Facilities” is superfluous, and therefore, it should not be added. The proposed new and revised definitions provide more than enough clarity.</p> <p>For MOD-012 [Dynamic System Data for System Modeling], we believe that the additional wording of “for plant and Generator Interconnection Facilities” is superfluous, and therefore, it should not be added. The proposed new and revised definitions provide more than enough clarity.</p>
<b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT.		
Entegra Power	Yes	SEE COMMENTS FOR QUESTION 2.

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Organization	Yes or No	Question 5 Comment
Group LLC		
<p><b>Response:</b> The SAR DT thanks you for your comment. Please see the response to your comments on Question 2.</p>		
Manitoba Hydro	Yes	The modifications at this point appear appropriate.
<p><b>Response:</b> The SAR DT thanks you for your comment.</p>		
Pepco Holdings, Inc - Affiliates	Yes	<p>There should be a clause that the TO shall be responsible for FAC-003 activities inside the TO's substation regardless of ownership of the Generation Interconnection Facility so we don't have to coordinate entry, etc. and they will likely have this handled for the bulk of their property anyway. R3 quarterly reporting of outage caused by vegetation is excessive for GOs. GOs would probably survey and cut as needed their Right of Ways at least once a year and probably already do so. TOs probably perform vegetation management on a multi-year cycle, so they might need to note quarterly if there is a veg. incident that occurs one or two quarters before the next round of survey/management on that line.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT. There were many suggestions for additional or alternate modifications to FAC-003 and these suggestions will be addressed by the SDT.</p>		

**6. Do you believe there are any other Transmission Owner or Transmission Operator standards or requirements that should be applicable to the Generator Owner or Generator Operator other than those identified?**

**Summary Consideration:** Stakeholders did not indicate the need to include any requirements or standards that were not already contained in the SAR. However, based on discussions with FERC and NERC staffs regarding previous Commission actions and NERC compliance filings, the SAR DT modified the SAR to give the SDT the flexibility to consider further modifications not identified in the Ad Hoc Report.

Organization	Yes or No	Question 6 Comment
AmerenUE, Power Operations Services	No	
American Transmission Company	No	
Bonneville Power Administration	No	
California ISO	No	
Competitive Power Ventures, Inc.	No	
Constellation Power Source Generation Inc.	No	
Detroit Edison Company	No	
E.ON U.S.	No	
El Dorado Energy LLC	No	
Electric Market Policy	No	
Energy Standards Working Group	No	

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Organization	Yes or No	Question 6 Comment
Entegra Power Group LLC	No	
Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners	No	
First Wind	No	
Florida Municipal Power Agency	No	
Independent Electricity System Operator	No	
Ingleside Cogeneration, LP	No	
ISO RTO Council Standards Review Committee	No	
Luminant	No	
Mesquite Power	No	
Midwest ISO Standards Collaborators	No	
North Carolina Electric Membership Corporation	No	
Pepco Holdings, Inc - Affiliates	No	
Prairie Power, Inc.	No	
PSEG Companies	No	



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Organization	Yes or No	Question 6 Comment
Public Utility District #1 of Clark County	No	
Sempra Generation	No	
SERC Planning Standards Subcommittee	No	
South Carolina Electric and Gas	No	
Tenaska, Inc.	No	
American Electric Power	No	At this point in time, AEP cannot identify any other TO/TOP requirements that should be considered.
<b>Response:</b> The SAR DT thanks you for your comment.		
Southern California Edison co.	No	Do not feel that this question is in the scope of Project 2010-07 as written
<b>Response:</b> The SAR DT thanks you for your comment.		
Duke Energy	No	However the SDT should perform a complete review.
<b>Response:</b> The SAR DT thanks you for your comment. The SDT will review all applicable standards changes as needed and required by the scope and purpose of the SAR.		
Manitoba Hydro	No	No manpower available at this time to examine all possibilities and scenarios.
<b>Response:</b> The SAR DT thanks you for your comment.		
Kansas City Power & Light	No	Not at this time.
<b>Response:</b> The SAR DT thanks you for your comment.		

**7. The next posting of the proposed revisions to these standards will include conforming changes to the measures and compliance elements, and will include an implementation plan. Please identify how much time you feel an entity will need to become fully compliant with the following new/revised requirements:**

The Generator Operator who has responsibility for monitoring the status of a special protection system or remedial action scheme at the generating facility for the benefit of Bulk Electric System reliability should notify the Transmission Operator when a change in status or capability occurs. (IRO-005)

**Summary Consideration:** The SAR DT thanks all stakeholders for their response to this question and its subcomponents. This series of questions was meant to provide input for the SDT in development of the required implementation plan that will accompany this project as it moves forward. The SAR DT would like to note that the three challenges most cited were training, agreements, and technical details. This information will be referred to the SDT for their consideration.

Organization	Time	Question 7 Comment
Pepco Holdings, Inc - Affiliates		No SPS currently in system.
<b>Response:</b> The SAR DT thanks you for your comment.		
California ISO		<p>We are not a GOP and hence we are unable to comment on this and other questions addressing the GOP compliance. However, the CAISO has the following comments on the effort required for other aspects of this Project:</p> <ul style="list-style-type: none"> <li>o As discussed under the answer to Question 5 above, it is not clear if the proposed changes to PRC-001 will require the Balancing Authority (BA) to understand the purpose and limitations of protection schemes associated with all of the Generator Interconnection Facilities in its area, even if such facilities are not under the control of the BA. If this is the case, significant and time-consuming effort will be required to identify the technical details of all of the Generator Interconnection Facilities in the BA and develop a training program to train applicable personnel on them. This is estimated to require up to 24 months.</li> <li>o If the proposed changes are approved they will affect 16 Standards affecting CAISO registrations. Most, if not all, of these changes will require modifications to the Reliability Standards Agreements (RSAs) between the CAISO and its Participating Transmission Operators to reflect the new wording and any delegated tasks. This may require 12 to 24 months to implement.</li> </ul>
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		

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Organization	Time	Question 7 Comment
Constellation Power Source Generation Inc.	1 year	
Energy Standards Working Group	1 year	
Tenaska, Inc.	1 year	
Bonneville Power Administration	1 year, if agreements need to be renegotiated.	
North Carolina Electric Membership Corporation	12 months	
SERC Planning Standards Subcommittee	12 months	
Kansas City Power & Light	12 months	Basically this is a training issue. It takes time to prepare the training materials and to train all Generator Operators considering shift schedules and to implement the training as part of an ongoing process.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Prairie Power, Inc.	12 months following Regulatory Approval	
Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners	18 months	
Luminant	18 months	

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Organization	Time	Question 7 Comment
South Carolina Electric and Gas	18 months	
Electric Market Policy	18 months to two years	We feel that, in most cases, such monitoring will only require RTU connectivity of the data points as well as incorporation into GOP control room displays.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Southern California Edison co.	3yrs	Pls refer to question No. 8
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Duke Energy	Approximately 3 months.	Depends upon measures and data requirements, but would probably be a short period of time.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
First Wind	Immediately unless status requires change to additional requirements which might be 18 months to two years)	The Generator Interconnection Facilities are already considered to be part of our Generator Plant and therefore have already been included in our existing compliance program.
<b>Response:</b> The SAR DT thanks you for your comment.		
Entegra Power Group LLC	NO COMMENT	
Public Utility District #1 of Clark County	No time	Clark has no SPS or RAS for which it is responsible.
<b>Response:</b> The SAR DT thanks you for your comment.		

**Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07**

Organization	Time	Question 7 Comment
Florida Municipal Power Agency	The amount of time it takes to compile documentation to fulfill the data retention requirements of the requirement	For most of these new requirements, the Entities are most likely fulfilling the requirements, but, may be missing the documentation to prove that they are doing so. So, to be auditably (“fully”) compliant, the Entities will need the amount of time it takes to build up sufficient evidence of compliance. This may only be a month to develop documentation, to a longer period of time to prove periodicity (e.g., a PRC-005 type of requirement - not PRC-005 itself - but a requirement that may need to be done periodically such as training to show that it is done periodically.
<p><b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.</p>		

- a. Each Generator Operator shall provide its operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Generation Facility and the Generation Interconnection Facility, and to implement directives of the Transmission Operator and Balancing Authority. (PER-001)

**Summary Consideration:** The SAR DT thanks all stakeholders for their response to this question and its subcomponents. This series of questions was meant to provide input for the SDT in development of the required implementation plan that will accompany this project as it moves forward. The SAR DT would like to note that the three challenges most cited were training, agreements, and technical details. This information will be referred to the SDT for their consideration.

Organization	Time	Question 7a Comment
American Electric Power		AEP believes that this requirement is not needed and should be out of the scope for this SAR.
<b>Response:</b> The SAR DT thanks you for your comment. These comments will be referred to the SDT.		
Pepco Holdings, Inc - Affiliates		These responsibilities and authorities are already in place for other standards.
<b>Response:</b> The SAR DT thanks you for your comment. These comments will be referred to the SDT.		
Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners	12 months	
North Carolina Electric Membership Corporation	12 months	
SERC Planning Standards Subcommittee	12 months	
South Carolina Electric and Gas	12 months	
Prairie Power, Inc.	12 months following	

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Organization	Time	Question 7a Comment
	Regulatory Approval	
Luminant	18 months	
Energy Standards Working Group	2 years	
Tenaska, Inc.	2 years	
Constellation Power Source Generation Inc.	2 years	Time is needed for training and terminology to percolate throughout the Generation Facility and that it be ingrained with the Operators.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Southern California Edison co.	3yrs	Pls refer to question No. 8
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Bonneville Power Administration	6 months	
Duke Energy	Approximately 24 months.	Multiple shifts and multiple facilities will require time to get training developed and delivered.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
First Wind	Less than 1 year	Memo from management should suffice.
Electric Market Policy	Less than one year	Memo from management should suffice.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Kansas City Power & Light	N/A	The Generator Operator should be operating equipment within the Generator Interconnection Facility at the

**Consideration of Comments on Generator Requirements at the Transmission Interface — Project 2010-07**

Organization	Time	Question 7a Comment
		direction of the Transmission Operator.
<b>Response:</b> The SAR DT thanks you for your comment. We will refer these comments to the SDT.		
Entegra Power Group LLC	NO COMMENT	
Public Utility District #1 of Clark County	No Time.	Clark’s Generator Operator personnel have responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Generation Facility and the Generation Interconnection Facility, and to implement directives of the Transmission Operator and Balancing Authority.
<b>Response:</b> The SAR DT thanks you for your comment.		
Florida Municipal Power Agency	See above	See above
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		



- b. Each Generator Operator shall implement an initial and continuing training program for all personnel responsible for operating the Generator Interconnection Facility to ensure the ability to operate the equipment in a reliable manner. (Per-002)

**Summary Consideration:** The SAR DT thanks all stakeholders for their response to this question. This series of questions was meant to provide input for the SDT in development of the required implementation plan that will accompany this project as it moves forward. The SAR DT would like to note that the three challenges most cited were training, agreements, and technical details. This information will be referred to the SDT for their consideration. The time needed to comply varied from 0-3 years.

Organization	Time	Question 7b Comment
E.ON U.S.		A training program for this would need to be created, procedures approved, implemented, and instituted at all power plants for all shifts. E.ON U.S. recommends that the addition of PER-002 R3 be coordinated with the existing standard PRC-001 R1, to eliminate redundancy.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
American Electric Power		AEP believes that this requirement is not needed and should be out of the scope for this SAR.
<b>Response:</b> The SAR DT thanks you for your comment. We will refer these comments to the SDT.		
Pepco Holdings, Inc - Affiliates	0-2 years	Currently establish training based on the RTO requirements. It would be Conectiv's policy to continue this training for this requirement. If other training is imposed upon the Entities, it may require up to two years to develop and initiate full training.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Entegra Power Group LLC	1 YEAR	
Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners	12 months	
North Carolina Electric	12 months	

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Organization	Time	Question 7b Comment
Membership Corporation		
SERC Planning Standards Subcommittee	12 months	
South Carolina Electric and Gas	12 months	
Energy Standards Working Group	2 years	
Tenaska, Inc.	2 years	
First Wind	2 years	Developing the training and providing it while accommodating shift employees will require a substantial amount of time.
<p><b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.</p>		
Constellation Power Source Generation Inc.	2 years	Time is needed to implement a training plan and revise it based on feedback from those being trained.
<p><b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.</p>		
Bonneville Power Administration	2-3 years, depending on the extent of equipment involved and size of facility.	
Luminant	24 months	
Prairie Power, Inc.	24 months following Regulatory Approval	

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Organization	Time	Question 7b Comment
Southern California Edison co.	3yrs	Pls refer to question No. 8
<b>Response:</b> The SAR DT thanks you for your comment.		
Duke Energy	Approximately 24 months.	Multiple shifts and multiple facilities will require time to get training developed and delivered.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Kansas City Power & Light	N/A	The Generator Operator should be operating equipment within the Generator Interconnection Facility at the direction of the Transmission Operator.
<b>Response:</b> The SAR DT thanks you for your comment. We will refer these comments to the SDT.		
Florida Municipal Power Agency	See above	See above
<b>Response:</b> The SAR DT thanks you for your comment.		
Public Utility District #1 of Clark County	Twelve months.	Clark’s generating operating personnel regularly engage in training however, to implement a Training Program as rigorous as the TOP Training Program will take some time to complete.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Electric Market Policy	two years	Developing the training and providing it while accommodating shift employees will require a substantial amount of time.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		

**c. The Generator Operator shall coordinate the operation of its Generator Interconnection Facility with the Transmission Operator to whom it interconnects to preserve Interconnection reliability. (TOP-001)**

**Summary Consideration:** The SAR DT thanks all stakeholders for their response to this question. This series of questions was meant to provide input for the SDT in development of the required implementation plan that will accompany this project as it moves forward. The SAR DT would like to note that the three challenges most cited were training, agreements, and technical details. This information will be referred to the SDT for their consideration. The time needed to comply varied from 0-3 years.

Organization	Time	Question 7c Comment
E.ON U.S.		Appears redundant with point e) below. There are already generator-outage reporting protocols in place. This would be an unnecessary addition to existing processes.
<b>Response:</b> The SAR DT thanks you for your comment.		
Pepco Holdings, Inc - Affiliates	0-2 years	Entity currently coordinates this operation with the TOP. If additional requirements are instituted by NERC, there may be a need to have time to develop new programs and policies to comply with additional requirements.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Constellation Power Source Generation Inc.	1 year	
Energy Standards Working Group	1 year	
Tenaska, Inc.	1 year	
Bonneville Power Administration	1 year, if agreements need to be renegotiated.	

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Organization	Time	Question 7c Comment
Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners	12 months	
North Carolina Electric Membership Corporation	12 months	
SERC Planning Standards Subcommittee	12 months	
Luminant	18 months	
South Carolina Electric and Gas	18 months	
Prairie Power, Inc.	24 months following Regulatory Approval	
Southern California Edison co.	3yrs	Pls refer to question No. 8
<b>Response:</b> The SAR DT thanks you for your comment.		
Kansas City Power & Light	6 months	If this is not already going on, this should not take long to implement.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Duke Energy	Approximately 3 months.	Depends upon measures and data requirements, but should be a short period of time.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
First Wind	Less than 1 year	There is already generator outage reporting protocols in place. This is just an addition to existing processes. Additionally, the Generator Interconnection Facility is already considered to be part of the Generating Facility and is likely already part of our existing compliance program.

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Organization	Time	Question 7c Comment
<b>Response:</b> The SAR DT thanks you for your comment.		
Electric Market Policy	Less than one year	There is already generator outage reporting protocols in place. This is just an addition to existing processes.
<b>Response:</b> The SAR DT thanks you for your comment.		
Entegra Power Group LLC	NO COMMENT	
Public Utility District #1 of Clark County	No Time.	Clark believes the operation of its generator is already under the direction of its TOP and that coordination has already occurred since the TOP has included the operation of Clark’s generator in its TOP-002 Normal Operations Plan.
<b>Response:</b> The SAR DT thanks you for your comment.		
Florida Municipal Power Agency	See above	See above

**d. The Transmission Operator has decision-making authority for the Generator Interconnection Operational Interface. (TOP-001)**

**Summary Consideration:** The SAR DT thanks all stakeholders for their response to this question. This series of questions was meant to provide input for the SDT in development of the required implementation plan that will accompany this project as it moves forward. The SAR DT would like to note that the three challenges most cited were training, agreements, and technical details. This information will be referred to the SDT for their consideration. The time needed to comply varied from 0-3 years.

Organization	Time	Question 7d Comment
Pepco Holdings, Inc - Affiliates	0-2 years	Coordination is required for the TOP to notify the GO/GOP of the decisions being implemented.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Constellation Power Source Generation Inc.	1 year	
Energy Standards Working Group	1 year	
Tenaska, Inc.	1 year	
Bonneville Power Administration	1 year, if agreements need to be renegotiated.	
Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners	12 months	
North Carolina Electric Membership Corporation	12 months	

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Organization	Time	Question 7d Comment
SERC Planning Standards Subcommittee	12 months	
Prairie Power, Inc.	12 months following Regulatory Approval	
Luminant	18 months	
South Carolina Electric and Gas	18 months	
Southern California Edison co.	3yrs	Pls refer to question No. 8
<b>Response:</b> The SAR DT thanks you for your comment. Please see the response to question 8.		
Kansas City Power & Light	6 months	If this is not already going on, this should not take long to implement.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Duke Energy	Approximately 3 months	Depends upon measures and data requirements, but should be a short period of time.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
First Wind	less than 1 year	Expect that, in most cases, the Interconnection Agreement between the generator and the TO or DP that it connects with already contains language that supports this because the Generator Interconnection Facility is already considered to be part of the Generating Facility.
<b>Response:</b> The SAR DT thanks you for your comment.		
Electric Market Policy	Less than one year	Expect that, in most cases, the Interconnection Agreement between the generator and the TO or DP that it connects with already contains language that supports this.
<b>Response:</b> The SAR DT thanks you for your comment.		



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Organization	Time	Question 7d Comment
Entegra Power Group LLC	NO COMMENT	
Public Utility District #1 of Clark County	No time.	Clark believes that existing standards already grant the TOP decision-making authority for the Generator Interconnection Operational Interface.
<b>Response:</b> The SAR DT thanks you for your comment.		
Florida Municipal Power Agency	See above	See above
<b>Response:</b> The SAR DT thanks you for your comment.		

**e. The Generator Operator shall notify the Transmission Operator of a change in status of the Generation Interconnection Facility.**

**Summary Consideration:** The SAR DT thanks all stakeholders for their response to this question. This series of questions was meant to provide input for the SDT in development of the required implementation plan that will accompany this project as it moves forward. The SAR DT would like to note that the three challenges most cited were training, agreements, and technical details. This information will be referred to the SDT for their consideration. The time needed to comply varied from 0-3 years.

Organization	Time	Question 7e Comment
Pepco Holdings, Inc - Affiliates	0-2 years	Entity currently coordinates this operation with the TOP. If additional requirements are instituted by NERC, there may be a need to have time to develop new programs and policies to comply with additional requirements.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Constellation Power Source Generation Inc.	1 year	
Energy Standards Working Group	1 year	
Tenaska, Inc.	1 year	
North Carolina Electric Membership Corporation	12 months	
SERC Planning Standards Subcommittee	12 months	
South Carolina Electric and Gas	12 months	
Prairie Power, Inc.	12 months following Regulatory Approval	

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Organization	Time	Question 7e Comment
Luminant	18 months	
Southern California Edison co.	3yrs	Pls refer to question No. 8
<b>Response:</b> The SAR DT thanks you for your comment.		
Kansas City Power & Light	6 months	If this is not already going on, this should not take long to implement.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Bonneville Power Administration	6 months.	
Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners	8 months	
Duke Energy	Approximately 3 months	Depends upon measures and data requirements, but should be a short period of time.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
First Wind	less than 1 year	Expect that, in most cases, the Interconnection Agreement between the generator and the TO or DP that it connects with already contains language that supports this.
<b>Response:</b> The SAR DT thanks you for your comment.		
Electric Market Policy	Less than one year	Expect that, in most cases, the Interconnection Agreement between the generator and the TO or DP that it connects with already contains language that supports this.
<b>Response:</b> The SAR DT thanks you for your comment.		
Entegra Power Group LLC	NO COMMENT	

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Organization	Time	Question 7e Comment
Public Utility District #1 of Clark County	No time.	Clark’s Generation Interconnection Facility status is already provided to the TOP in real time over the TOP’s SCADA system.
<b>Response:</b> The SAR DT thanks you for your comment.		
Florida Municipal Power Agency	See above	See above
<b>Response:</b> The SAR DT thanks you for your comment.		

f. The Generator Operator shall operate the Generation Interconnection Facility within Facility Ratings. (TOP-004)

**Summary Consideration:** The SAR DT thanks all stakeholders for their response to this question. This series of questions was meant to provide input for the SDT in development of the required implementation plan that will accompany this project as it moves forward. The SAR DT would like to note that the three challenges most cited were training, agreements, and technical details. This information will be referred to the SDT for their consideration. The time needed to comply varied from 0-3 years.

Organization	Time	Question 7f Comment
American Electric Power		AEP does not believe that the added requirement is necessary as the Generator Interconnection Facility should be adequately sized to handle the output of the generator.
<b>Response:</b> The SAR DT thanks you for your comment. Based on a review of the full body of industry comments, we believe that the standards actions proposed in this SAR are appropriate. Specific modifications will be determined by the SDT.		
Bonneville Power Administration	0 months.	
Pepco Holdings, Inc - Affiliates	0-2 years	Entity currently operates within the facility ratings as required under FAC. If additional requirements are instituted by NERC, there may be a need to have time to develop new programs and policies to comply with additional requirements
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Constellation Power Source Generation Inc.	1 year	
Energy Standards Working Group	1 year	
Tenaska, Inc.	1 year	
North Carolina Electric Membership Corporation	12 months	
SERC Planning Standards	12 months	

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Organization	Time	Question 7f Comment
Subcommittee		
Prairie Power, Inc.	12 months following Regulatory Approval	
Luminant	18 months	
South Carolina Electric and Gas	18 months	
Southern California Edison co.	3yrs	Pls refer to question No. 8
<b>Response:</b> The SAR DT thanks you for your comment.		
Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners	6 months	
Kansas City Power & Light	6 months	If this is not already going on, this should not take long to implement.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Duke Energy	Approximately 3 months.	Depends upon measures and data requirements, but should be a short period of time.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
First Wind	less than 1 year	The Generator Interconnection Facility is already considered to be part of the Generator Unit and the facility should be compliant currently with FAC standards.
<b>Response:</b> The SAR DT thanks you for your comment.		
Electric Market Policy	less than one year	Facility should be compliant currently with FAC standards.

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Organization	Time	Question 7f Comment
<b>Response:</b> The SAR DT thanks you for your comment.		
Entegra Power Group LLC	NO COMMENT	
Public Utility District #1 of Clark County	No time.	The Generation Interconnection Facilities of Clark have ratings that exceed the maximum generating capability of the interconnected generation facility.
<b>Response:</b> The SAR DT thanks you for your comment.		
Florida Municipal Power Agency	See above	See above
<b>Response:</b> The SAR DT thanks you for your comment.		

**g. The Generator Operator shall disconnect the Generation Interconnection Facility immediately in coordination with the Transmission Operator when time permits or as soon as practical thereafter if an overload or other abnormal condition threatens equipment or personnel safety. (TOP-008)**

**Summary Consideration:** The SAR DT thanks all stakeholders for their response to this question. This series of questions was meant to provide input for the SDT in development of the required implementation plan that will accompany this project as it moves forward. The SAR DT would like to note that the three challenges most cited were training, agreements, and technical details. This information will be referred to the SDT for their consideration. The time needed to comply varied from 0-3 years.

Organization	Time	Question 7g Comment
E.ON U.S.		In case of overload, the E.ON U.S. GOP has an overload current relay that already removes a generating unit from the grid immediately. Moreover, it is expected that in most cases an Interconnection Agreement between the generator and TO that it connects with already contains language supportive of this.
<b>Response:</b> The SAR DT thanks you for your comment.		
Pepco Holdings, Inc - Affiliates	0-2 years	Entity currently coordinates this operation with the TOP. If additional requirements are instituted by NERC, there may be a need to have time to develop new programs and policies to comply with additional requirements.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Constellation Power Source Generation Inc.	1 year	
Energy Standards Working Group	1 year	
Tenaska, Inc.	1 year	
Bonneville Power Administration	1 year, if agreements need to be renegotiated.	



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Organization	Time	Question 7g Comment
Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners	12 months	
North Carolina Electric Membership Corporation	12 months	
SERC Planning Standards Subcommittee	12 months	
South Carolina Electric and Gas	12 months	
Prairie Power, Inc.	12 months following Regulatory Approval	
Luminant	36 months	
Southern California Edison co.	3yrs	Pls refer to question No. 8
<b>Response:</b> The SAR DT thanks you for your comment.		
Kansas City Power & Light	6 months	If this is not already going on, this should not take long to implement.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
Duke Energy	Approximately 3 months.	Depends upon measures and data requirements, but should be a short period of time.
<b>Response:</b> The SAR DT thanks you for your comment. All timing issues related to the implementation plan will be addressed by the SDT.		
First Wind	less than 1 year	The Generator Interconnection Facility is already considered to be part of the Generator Unit. Expect that, in most cases, the Interconnection Agreement between the generator and the TO or DP that it connects with already contains language that supports this.

**Consideration of Comments on Generator Requirements at the Transmission Interface — Project 2010-07**

Organization	Time	Question 7g Comment
<b>Response:</b> The SAR DT thanks you for your comment.		
Electric Market Policy	less than one year	Expect that, in most cases, the Interconnection Agreement between the generator and the TO or DP that it connects with already contains language that supports this.
<b>Response:</b> The SAR DT thanks you for your comment.		
Entegra Power Group LLC	NO COMMENT	
Public Utility District #1 of Clark County	No time.	Clark has experienced no operating conditions where it had to disconnect the Generation Interconnection Facility immediately due to an overload or other abnormal condition that threatened equipment or personnel safety.
<b>Response:</b> The SAR DT thanks you for your comment.		
Florida Municipal Power Agency	See above	See above
<b>Response:</b> The SAR DT thanks you for your comment.		

**8. If you have any other comments on this SAR or proposed standard revisions and NERC Glossary modifications that you have not already provided in response to the prior questions, please provide them here.**

**Summary Consideration:** The SAR DT thanks all stakeholders for their response to this question. Many of the comments were addressed in earlier responses. Based on discussions with FERC and NERC staffs regarding previous Commission actions and NERC compliance filings, the SAR DT modified the SAR to give the SDT the flexibility to consider further modifications not identified in the Ad Hoc Report. Finally, revisions to the SAR also allow the SDT the option of merging the changes into one new standard or into several different existing standards.

Organization	Question 8 Comment
<p>Constellation Power Source Generation Inc.</p>	<p>Constellation would like to thank the Ad-Hoc group for the excellent work they did in creating the GOTO Final Report. In particular, here are a few excerpts that Constellation agrees with, and would like the future SDT to consider:</p> <ul style="list-style-type: none"> <li>oThe Generator Owner or Generator Operator that owns and/or operates a Generator Interconnection Facility, that is, a sole-use facility that interconnects the generator to the grid, should not be registered as a Transmission Owner or Transmission Operator by virtue of owning or operating its Generator Interconnection Facility.</li> <li>oA Generator Interconnection Facility is considered as though part of the generating facility specifically for purposes of applying Reliability Standards to a Generator Owner or Generator Operator.</li> <li>oAfter review of the existing Transmission Operator requirements that are not currently applicable to Generator Operators, no existing Transmission Operator requirements should apply to Generator Operators as a result of the Generator Interconnection Facility.</li> </ul>
<p><b>Response:</b> The SAR DT thanks you for your comments. The SAR DT supports the three concepts identified.</p>	
<p>EI Dorado Energy LLC</p>	<p>EI Dorado Energy commends the efforts of the NERC Ad Hoc Group, and supports the Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface, and Standards Authorization Request addressing the various Standards containing GO/GOP and TO/TOP Requirements. The Final Report and SARs are products of detailed analysis and thoughtful consideration of the myriad issues surrounding the reliability implications of ownership and operation of Generator Interconnection Facilities. It is noteworthy - though hardly surprising - that, after many months of study, the GO/TO Task Force, a balanced group comprised of members from a broad spectrum of functional categories, concluded that only modest changes to the Reliability Standards would be required in order to ensure that generator interconnection facilities are operated reliably. When implemented, the recommendations included in the Final Report and SARs should go a long way toward providing the regulatory and compliance certainty needed by generators who own or operate Generator Interconnection Facilities. Accordingly, EI Dorado Energy encourages the Standards Drafting Team to act quickly to implement the SARs.</p>

Organization	Question 8 Comment
<p><b>Response:</b> The SAR DT thanks you for your comment.</p>	
<p>Competitive Power Ventures, Inc.</p>	<p>Every effort should be made to precisely describe requirements that directly correspond to, and address, the reliability issues framed by the GO/TO Ad Hoc Group. Particularly, "interconnection facilities" should be defined to account for and exclude various transmission configurations on the generator side of the interconnection point that do not create network power flows or otherwise operate as bona fide transmission systems.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT.</p>	
<p>Entegra Power Group LLC, i.e., Gila River Power and Union Power Partners</p>	<p>FAC-003 - Applicability apply to GIF above 200 kV that exceed two spans should be revised to "less than one-half mile" as span lengths vary considerably. For example we have 3 spans over 1/4 mile. R1. requirement to "keep current, a formal TVMP" should allow latitude for those entities with one-quarter mile of radial connecting transmission, all visible from the office window, to have a less than a formal program, or at least a very SIMPLE program.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT.</p>	
<p>First Wind</p>	<p>FAC-003 - Step 4.5 should be clearly identified as a “qualifier” for Generator Owner applicability. Although not the intent of the standard, as currently drafted, the requirements apply to all Generator Owners. Additionally we recommend modifications to address a disqualifier if the plant is located in an environment whose natural environment would prevent vegetation from growing that could interfere with the reliability of the bulk Electric System. The following changes are recommended.</p> <p>4.4. Generator Owner.</p> <p>4.5. This standard shall apply to the Generator Interconnection Facility above 200 kV that exceed two spans from the generator property line or are otherwise deemed critical by the Regional Entity below 200 kV (subject to the two-span criteria.). This standard does not apply to all Generator Interconnection Facilities outside this threshold and those facilities located in an area whose environment would prevent vegetation from growing. A generating facility located underground, in the high desert or within a fully developed urban area where vegetation disturbances could not occur should not be required to have a vegetation management program.</p> <ul style="list-style-type: none"> <li>o MOD-010 - The changes made in this standard are not reflected in the associated standard, MOD-011 (possibly because MOD-011 is not FERC approved).</li> <li>o MOD-012 - The changes made in this standard are not reflected in the associated standard, MOD-013 (possibly because MOD-013 is not FERC approved).</li> <li>o PER-001 - The Purpose statement in the Standard needs to be modified to include GOP.</li> </ul>

Organization	Question 8 Comment
	<p>o PER-002 - The Purpose statement in the Standard needs to be modified to include GOP. We recommend the addition of PER-002 R3 is coordinated with the existing standard PRC-001 R1 to eliminate redundancy. While PER-002 R3 more clearly calls for training, PRC-001 R1 implies training. The two standards should be combined into one training requirement. PRC-001 R1 "Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area." We recommend retiring PRC-001 R1 and modifying the proposed standard PER-002 R3 as shown below:</p> <p style="padding-left: 40px;">Each Generator Operator shall implement an initial and continuing training program for all operating personnel that are responsible for operating the Generator Protection System Equipment, including the Generator Interconnection Facility that verifies the personnel's ability and understanding to operate the equipment in a reliable manner.</p> <p>o TOP-002 - Requirement R14 contains sub-requirements R14.1 and R14.2 that were retired August, 1, 2007. Suggest deleting the retired requirements with the proposed revision.</p> <p>o TOP-004 - Requirement R7 has been added for the Generator Operator; however, the Generator Operation has not been added to the Applicability.</p> <p>o TOP-008 - The Purpose statement in the Standard needs to be modified to include GOP.</p>
<p><b>Response:</b> The SAR DT thanks you for your comments. They will be referred to the SDT.</p>	
California ISO	<p>It does not appear that any of the Measures in the proposed Standards have been revised to reflect the new and/or revised requirements.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. The intent was to post just the initial set of proposed requirements to provide stakeholders with a sense of the scope of the project. The SDT assigned to this project will need to work with stakeholders to develop not only the requirements, but all the other elements needed to support those requirements, including measures, violation risk factors, time horizons, violation severity levels, evidence retention, etc.</p>	
North Carolina Electric Membership Corporation	<p>NC EMC is concerned with the decision to use "revisions to the latest versions of the following standards" that were included in red-line format in this SAR: o BAL-005 o CIP-002 o EOP-001, -003, -004, -008 o FAC-001, -003, -008, -009 o IRO-005 o MOD-010, -012 o PER-001, -002 o PRC-001, -004, -005 o TOP-001, -002, -003, -004, -008 o VAR-001, -002</p> <p>The use of these versions of the standards, many of which have been revised, approved by the NERC Board of Trustees and filed with FERC emphasizes the flaw in a regulatory approval process that is not uniform throughout North America. Not all registered entities are FERC jurisdictional, therefore, are already required to comply with Reliability Standards upon NERC Board of Trustees approval. Of the standards that are included in this SAR, three projects not including interpretations have been retired, modified, or new standards created that are now complied with by some registered entities. The projects include; Project 2006-01 "System Personnel Training" PER-002, PER-004, and PER-005, Pre-2006 "Operate Within Interconnection Reliability Operating Limits" IRO-007 through IRO-010 and Project 2008-06 "Cyber Security" Order</p>

Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07

Organization	Question 8 Comment
	<p>706 – CIP-002 through CIP-009. In addition, it is difficult to determine whether there is any coordination between the activities of this SAR drafting team and those of the many existing drafting teams that are also revising standards. NCEMC understands the dilemma of how to revise standards in a regulatory environment that has no defined time-line guidelines for approval of standards upon filing with FERC, but reminds NERC, the Standards Committee and drafting teams that the process must address the varying regulatory approval processes in North America.</p>
<p><b>Response:</b> The SAR DT thanks you for your comments. They will be referred to the SDT. The SDT will work with the latest BOT approved versions of the standards in support of your comment.</p>	
SERC Planning Standards Subcommittee	No other comments
Kansas City Power & Light	No other comments.
South Carolina Electric and Gas	none
National Rural Electric Cooperative Association (NRECA)	<p>NRECA is concerned with the decision to use “revisions to the latest versions of the following standards” that were included in red-line format in this SAR: o BAL-005 o CIP-002 o EOP-001, -003, -004, -008 o FAC-001, -003, -008, -009 o IRO-005 o MOD-010, -012 o PER-001, -002 o PRC-001, -004, -005 o TOP-001, -002, -003, -004, -008 o VAR-001, -002 The use of these versions of the standards, many of which have been revised, approved by the NERC Board of Trustees and filed with FERC emphasizes the flaw in a regulatory approval process that is not uniform throughout North America. Not all registered entities are FERC jurisdictional, therefore, are already required to comply with Reliability Standards upon NERC Board of Trustees approval. Of the standards that are included in this SAR, three projects not including interpretations have been retired, modified, or new standards created that are now complied with by some registered entities. The projects include; Project 2006-01 – System Personnel Training – PER-002, PER-004, and PER-005, Pre-2006 – Operate Within Interconnection Reliability Operating Limits – IRO-007 through IRO-010 and Project 2008-06 – Cyber Security – Order 706 – CIP-002 through CIP-009. In addition, it is difficult to determine whether there is any coordination between the activities of this SAR drafting team and those of the many existing drafting teams that are also revising standards. NRECA understands the dilemma of how to revise standards in a regulatory environment that has no defined time-line guidelines for approval of standards upon filing with FERC, but reminds NERC, the Standards Committee and drafting teams that the process must address the varying regulatory approval processes in North America.</p>
<p><b>Response:</b> The SAR DT thanks you for your comments. They will be referred to the SDT. The SDT will work with the latest BOT approved versions of the standards in support of your comment.</p>	
Electric Market Policy	oEOP-003 - I do not understand the addition of GOP to this standard. Additionally, the Purpose statement is not in

**Consideration of Comments on Generator Requirements at the Transmission Interface – Project 2010-07**

Organization	Question 8 Comment
	<p>alignment with the additional GOP applicability.</p> <ul style="list-style-type: none"> <li>oFAC-003 - Step 4.5 should be clearly identified as a “qualifier” for Generator Owner applicability. Although not the intent of the standard, as currently drafted, the requirements apply to all Generator Owners.</li> <li>oMOD-010 - The changes made in this standard are not reflected in the associated standard, MOD-011 (possibly because MOD-011 is not FERC approved).</li> <li>oMOD-012 - The changes made in this standard are not reflected in the associated standard, MOD-013 (possibly because MOD-013 is not FERC approved).</li> <li>oPER-001 - The Purpose statement is not in alignment with the additional GOP applicability.</li> </ul>
<p><b>Response:</b> The SAR DT thanks you for your comments. They will be referred to the SDT.</p>	
American Electric Power	<p>Overall, AEP supports the concept of this SAR, but we question the number of new requirements that are being brought in scope. Some of the requirements added appear to encourage this SAR to reach farther than the scope of addressing the Generator Interconnection Facilities.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT. The intent of the SAR was to collect feedback on the proposed scope of this project.</p>	
Prairie Power, Inc.	<p>PPI contends this SAR and associated requirement additions and revisions go well beyond the recommendations from the Group needed to resolve the barrier issue between Transmission Operator and Generator Operator. The FAC-003 standard revision, so that vegetation management can be enforced for transmission lines which interconnect generators to transmission, is really all that is necessary. All these other changes just add confusion to already overlapped requirements.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT. One of the goals of this project is to eliminate ‘overlaps’ so there is a clear line of responsibility for each facility.</p>	
Southern California Edison co.	<p>SCE believes that implementing changes type of changes proposed in 2010-07 should be looked at as a whole/ one entire project rather than piece meal as alluded to in question number 7 of the comments form. As such, it is the company’s position that approximately 3yrs is right amount of time to reliably implement the proposed revisions to the suite of standards as identified in Project 2010-07. A 3 yr timeline would enable the project to be fully scoped out and budgeted, and allow for: completion of the necessary engineering studies; design, procurement and construction of any new facilities necessitated by the revisions; development of any new operations and communications procedures with respect to both the transmission and generation facilities; and the training of personnel related to any new procedures.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. The SAR has been modified to allow the SDT the option of merging the changes into one new standard or an</p>	

Organization	Question 8 Comment
	existing standard(s). All timing issues related to the implementation plan will be addressed by the SDT. As envisioned, all requirements would become effective at the same time as the proposed definitions to ensure that there are no gaps in the body of NERC requirements.
Sempra Generation	Sempra Generation commends the efforts of the NERC Ad Hoc Group, and supports the Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface, and Standards Authorization Request addressing the various Standards containing GO/GOP and TO/TOP Requirements. The Final Report and SARs are products of detailed analysis and thoughtful consideration of the myriad issues surrounding the reliability implications of ownership and operation of Generator Interconnection Facilities. It is noteworthy - though hardly surprising - that, after many months of study, the GO/TO Task Force, a balanced group comprised of members from a broad spectrum of functional categories, concluded that only modest changes to the Reliability Standards would be required in order to ensure that generator interconnection facilities are operated reliably. When implemented, the recommendations included in the Final Report and SARs should go a long way toward providing the regulatory and compliance certainty needed by generators who own or operate Generator Interconnection Facilities. Accordingly, Sempra Generation encourages the Standards Drafting Team to act quickly to implement the SARs.
<p><b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT.</p>	
AmerenUE, Power Operations Services	<p>The items in Question #7 illustrate the need for a written Agreement or Procedure between the GO, GOP, TO and TOP on how to comply with these new, and modified, Requirements. An Agreement or Procedure would provide the certainty of:</p> <ul style="list-style-type: none"> <li>o Assignable and measurable responsibilities,</li> <li>o Mutual agreement on specific actions, and</li> <li>o Implementation deadlines.</li> </ul> <p>Without such an Agreement or Procedure, there will be no auditable commitment to defined specific actions, predetermined responsibilities and closure of the reliability gap in total.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. The SDT will discuss these kinds of issues, but such agreements are covered by the NERC Rules of Procedures and it is outside the scope of both the SAR DT and the SDT to propose changes to the NERC Rules of Procedure.</p>	
ERCOT ISO	The proposed language in Requirements 9 and 10 (hereafter R9 and R10) for NERC Standard TOP-001-X, Reliability Responsibilities and Authorities, clouds the responsibilities among different functional entities that are and are not held accountable to this Standard. Specifically, the first part of the sentence in R9 states: “The Generator Operator, in accord with the expectations defined by the Transmission Operator, shall coordinate...” This statement is overly broad and vague. For instance, is the statement meant to refer to Interconnection Agreements that have been entered into between Generator Operators and Transmission Operators? Or, is the statement intended to include other agreements as well? In addition, there



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Organization	Question 8 Comment
	<p>are items listed in R9 (i.e., switching elements, outage planning, and real-time and anticipated emergency conditions) which are normally the responsibilities of the Transmission Owner and/or the Reliability Coordinator; however, NERC Standard TOP-001-X is not applicable to the Transmission Owner or the Reliability Coordinator. Also, the item “other conditions mutually agreed-upon by the Generator Operator and Transmission Operator” is vague and ambiguous and should be clarified in order not to confuse tasks that may be more aligned with the responsibilities of the Transmission Owner or the Reliability Coordinator. Furthermore, R9 and R10 strongly imply and explicitly give the Transmission Operator authority to take action “in order to preserve Interconnection reliability.” This type of wide-area authority is meant to describe Reliability Coordinator-related obligations. The NERC Function Reliability Model is clear in defining the function and tasks of reliability operations. The Reliability Coordinator is responsible, in concert with other Reliability Coordinators, for the Interconnection as a whole; not the Transmission Operator. Lastly, it is unclear how an entity registered for multiple functions (for example, Reliability Coordinator and Transmission Operator) would be held accountable under this NERC Standard. If the intent is that R9 and R10 are to be the obligations only of those functional entities for which the NERC Standard is applicable, then the language in the NERC Standard should clearly state that intent.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT. As envisioned, the SDT will coordinate its work with the Functional Model Working Group to ensure that any new functional entities are identified with a clear definition, and a clear scope of responsibilities and tasks.</p>	
PSEG Companies	<p>The PSEG Companies support this approach to ensure that all components of the BES are adequately covered by the reliability standards. The drafting team has done a good job of identifying the appropriate areas of concern.</p>
<p><b>Response:</b> The SAR DT thanks you for your comment.</p>	
Transmission Owner/Generation Owner	<p>The SAR for Project 2010-07 proposes a number of specific changes to existing Reliability Standards based on the GOTO Report. FPL believes that identifying the exact standards and language for revision should be the purview of a Standards Drafting Team and not embedded within the SAR itself. The Standards Drafting Team should be empowered to review the GOTO Report and make independent recommendations. Many of the questions contained in this SAR comment form are more appropriate for a Standard's drafting comment form and not for a SAR. The place to discuss and evaluate specific wording changes as applicable to standards revisions should be contained in the Standard Drafting process. The SAR should lay the foundation for the need for changes, not disseminate or debate exact changes. FPL would recommend that the sections “Brief” and “Detailed Description” of the SAR should be amended as follows: “Taking into consideration the GOTO Final Report from November 2009, the need for revisions to existing standards may exist. The Standards Drafting Team will evaluate the recommendations of the GOTO Final Report and recommend changes as necessary.”</p>
<p><b>Response:</b> The SAR DT thanks you for your comment and agrees. The SAR DT has assembled the specific suggestions for revisions to definitions and requirements provided in response to this SAR. As envisioned, the SDT will consider those comments. Note that the SAR has been modified to give the SDT the flexibility to address this concern.</p>	

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Organization	Question 8 Comment
Northeast Power Coordinating Council	The term “two spans” is used in the Introductory Section of this Comment Form (Conclusions Item 6, Recommendations Item 3), and will need a clear, and specific definition. “Generally” is not a word to be used in a definition.
<b>Response:</b> The SAR DT thanks you for your comments.They will be referred to the SDT.	
Xcel Energy	There are many other standards development projects underway that are modifying the same standard. It is unclear as to how the changes will be coordinated amongst the many teams.
Xcel Energy	There are many other standards development projects underway that are modifying the same standard. It is unclear as to how the changes will be coordinated amongst the many teams.
<b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT. As envisioned, the SDT will work with the latest BOT approved versions of the standards and will coordinate its work with all other SDTs that are actively working on the same standards.	
ISO RTO Council Standards Review Committee	These SAR and associated draft standards changes go beyond what is needed to resolve the GO/TO GOP/TOP registration issue. The only real changes that are needed are to include adding GO and GOP applicability in the FAC-003 standard so that vegetation management can be enforced for lines built to interconnect generators without registering the GO/GOP as a TO/TOP. All additional changes just add confusion and cause significant coordination issues with other draft standard changes.This proposed SAR and associated standards’ modifications does not appear to have been coordinated with any other drafting team. There are many standards and requirements that are in various states of change. For instance, the TOP standards have been significantly modified and are nearing the ballot phase. Coordination needs to occur before these changes are balloted.
Midwest ISO Standards Collaborators	These SAR and associated draft standards changes go beyond what is needed to resolve the GO/TO GOP/TOP registration issue. The only real changes that are needed are to include adding GO and GOP applicability in the FAC-003 standard so that vegetation management can be enforced for lines built to interconnect generators without registering the GO/GOP as a TO/TOP. All additional changes just add confusion and cause significant coordination issues with other draft standard changes.This proposed SAR and associated standards’ modifications does not appear to have been coordinated with any other drafting team. There are many standards and requirements that are in various states of change. For instance, the TOP standards have been significantly modified and are nearing the ballot phase. Coordination needs to occur before these changes are balloted.
<b>Response:</b> The SAR DT thanks you for your comment. It will be referred to the SDT. The purpose of this SAR was to seek stakeholder views on the scope of requirements that may need modification, and most stakeholders who participated in this comment period support modifications that go beyond modifying only the Transmission Vegetation Management standard.	

Organization	Question 8 Comment
E.ON U.S.	<p>This SAR should only apply to those separate entity GOPs that already adhere to an OATT. Those GOPs should be required to register additionally as a TO/TOP. This should not apply to a GOP within a Corporation that includes TO/TOP that adhere to an OATT, and have already defined an internal division of responsibilities for the Transmission Interface between the GOP and TOP.</p>
<p><b>Response:</b> Based on a review of the full body of industry comments, we believe that there is a reliability need for this SAR. Further, registration issues are outside the scope of the SAR DT.</p>	
Energy Standards Working Group	<p>We commend the work of the team that produced the report and this SAR and suggest that the Standard Drafting Team give due deference to the report with the modifications that we have suggested in questions 4 and 5 above. In addition, EPSC would highlight the following conclusions that follow from the report:</p> <ul style="list-style-type: none"> <li>o The Generator Owner or Generator Operator that owns and/or operates a Generator Interconnection Facility, that is, a sole-use facility that interconnects the generator to the grid, should not be registered as a Transmission Owner or Transmission Operator by virtue of owning or operating its Generator Interconnection Facility</li> <li>o A Generator Interconnection Facility is considered as though part of the generating facility specifically for purposes of applying Reliability Standards to a Generator Owner or Generator Operator</li> <li>o After review of the existing Transmission Operator requirements that are not currently applicable to Generator Operators, no existing Transmission Operator requirements should apply to Generator Operators as a result of the Generator Interconnection Facility</li> </ul>
<p><b>Response:</b> The SAR DT thanks you for your comment. The SAR DT agrees with your conclusions.</p>	
Tenaska, Inc.	<p>We commend the work of the team that produced the report and this SAR and suggest that the Standard Drafting Team give due deference to the report with the modifications that we have suggested in questions 4 and 5 above. In addition, we would highlight the following conclusions that follow from the report:</p> <ul style="list-style-type: none"> <li>o The Generator Owner or Generator Operator that owns and/or operates a Generator Interconnection Facility, that is, a sole-use facility that interconnects the generator to the grid, should not be registered as a Transmission Owner or Transmission Operator by virtue of owning or operating its Generator Interconnection Facility</li> <li>o A Generator Interconnection Facility is considered as though part of the generating facility specifically for purposes of applying Reliability Standards to a Generator Owner or Generator Operator</li> <li>o After review of the existing Transmission Operator requirements that are not currently applicable to Generator Operators, no existing Transmission Operator requirements should apply to Generator Operators as a result of the Generator Interconnection Facility</li> </ul>

Organization	Question 8 Comment
	<b>Response:</b> The SAR DT thanks you for your comment. The SAR DT agrees with your conclusions.

The NERC logo consists of the letters "NERC" in a bold, black, sans-serif font. A horizontal blue bar is positioned directly beneath the letters.

NORTH AMERICAN ELECTRIC  
RELIABILITY CORPORATION

# Project 2010-07: Generator Requirements at the Transmission Interface

White Paper Proposal for Informal Comment

to ensure  
the reliability of the  
bulk power system

March 2011

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# **Project 2010-07: Generator Requirements at the Transmission Interface White Paper Proposal for Informal Comment**

## **Introduction**

The Bulk Electric System<sup>1</sup> consists of many parts, including power plants and transmission facilities. While most transmission facilities operate as part of the overall integrated grid, a number of transmission facilities operate more like an extension cord to interconnect power plants and loads to the bulk power system.<sup>2</sup> These transmission facilities that connect power plants to the integrated grid are commonly known as generator interconnection facilities.

Power plants, and their respective pieces and parts, come in all sizes and configurations. Some plants consist of just a single generating unit, other plants consist of multiple generating units, and still others consist of multiple generating units spread over several thousand acres. While not all power plants are considered part of the Bulk Electric System, ultimately, all the plants are interconnected to the bulk power system via their generator interconnection facilities. Of concern is how to classify all such generating facilities, including their generator interconnection facilities, to determine what level of reliability is needed for such facilities.

## **Objective**

The purpose of Project 2010-07—Generator Requirements at the Transmission Interface is to ensure that all generator-owned Facilities<sup>3</sup> that are considered part of the Bulk Electric System are identified and that the level of reliability needed to operate such Facilities is appropriately covered under NERC’s Reliability Standards. This will be accomplished by proposing a set of changes to existing standard requirements, introducing new requirements, and, if necessary, modifying definitions of some NERC-defined terms. The collective efforts will add clarity to Generator Owners and Generator Operators regarding their reliability standard obligations at the interface with the integrated bulk power system.

Since the formation of the Project 2010-07 Standard Drafting Team (SDT) in December 2010, the SDT has focused on reworking the Generator Requirements at the Transmission Interface Ad Hoc Group’s<sup>4</sup> (GOTO Ad Hoc Group) original proposed plan for addressing generator

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<sup>1</sup>The current definition of “Bulk Electric System” in the [NERC’s Glossary of Terms](#) reads: “As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.” This definition is undergoing significant revision under [Project 2010-17—Definition of Bulk Electric System](#).

<sup>2</sup> This paper uses the term “bulk power system” as it is defined in Section 215 of the Federal Power Act: “(A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy.”

<sup>3</sup> “Facility” is defined in [NERC’s Glossary of Terms](#) as “A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)”

<sup>4</sup> NERC formed the [Generator Requirements at the Transmission Interface Ad Hoc Group](#) in 2009 to analyze and make recommendations for establishing general criteria for determining whether Generator Owners and Generator Operators should be registered for Transmission Owner and Transmission Operator requirements in NERC’s Reliability Standards.

requirements at the transmission interface. Based on feedback from the industry, along with input from NERC and FERC staffs, the GOTO Ad Hoc Group made a series of recommendations that included changes to various reliability standards, the modification of existing definitions, and the creation of some new definitions. However, based on more recent feedback from industry and regulators, and after taking into account other standards projects under development, the SDT decided that the plan of proposing new definitions, modifying other definitions, and making changes to dozens of standards was no longer necessary.

The SDT believes it is appropriate to classify various generating Facilities and Elements (including generator interconnection facilities) as part of the Bulk Electric System. The SDT also believes that qualifying generator interconnection facilities should be classified as transmission. That does not mean, however, that a Generator Owner or Generator Operator should be required to automatically register as a Transmission Owner or Transmission Operator simply because it owns and/or operates transmission Elements or Facilities. While qualifying Generator Owners and Generator Operators can be classified as owning and operating electric transmission Elements and Facilities, these are most often not part of the integrated bulk power system, and as such should not be subject to the same level of standards applicable to Transmission Owners and Transmission Operators who own and operate transmission Facilities and Elements that are part of the integrated bulk power system.

Requiring any classification that subjects Generator Owners and Generator Operators to all the standards applicable to Transmission Owners and Transmission Operators would do little, if anything, to improve the reliability of the Bulk Electric System. When the transmission Elements and Facilities owned and operated by Generator Owners and Generator Operators are non-network/non-integrated transmission, applying *all* standards applicable to Transmission Owners and Transmission Operators would have little effect on the overall reliability of the Bulk Electric System when compared to the operation of the equipment that actually produces electricity – the generation equipment itself.

To maintain an adequate level of reliability in the Bulk Electric System, a clear delineation of responsibilities and authority at the interface between Generator Owners/Operators and Transmission Owners/Operators is needed. This can be accomplished by properly applying selected standards or specific standard requirements to Generator Owners and Generator Operators. The SDT is recommending a plan to modify the Purpose, the Functional Entity section, requirements, and measures of a selected group of standards to make them applicable to Generator Owners and Generator Operators, and to add clarity to such standards regarding generator interconnection facilities.

Note that at this stage in its work, the SDT has made no final decisions on its proposed plan; rather, it is seeking informal feedback from the industry regarding its assumptions and recommendations. Throughout the informal comment stage, the SDT plans to rely heavily on this informal input and feedback to lessen the need to expend limited industry resources on developing specific and exacting standards changes. At this informal stage, the SDT has not developed definitional changes, VSLs, VRFs, Implementation Plans, etc. for its proposed changes; those will be developed as needed once the project progresses further and proposed changes are finalized.



## Proposed Next Steps and Review of Reliability Standards

The Project 2010-07 Standard Drafting Team (SDT) proposes the following recommendations to clearly identify the appropriate generation Facilities and the standards requirements that should apply to such generation Facilities to ensure that the reliability of the Bulk Electric System is maintained:

- 1. Add “Generator Owner” to the Applicability section of FAC-001-0 and add a requirement and a measure to address the responsibilities specific to the Generator Owner.**

FAC-001-0—Facility Connection Requirements currently applies to Transmission Owners and addresses the need for Transmission Owners to establish facility connection and performance requirements. While the standard requires Transmission Owners to address connection requirements for “generation facilities, transmission facilities, and end-user facilities,” it does not address the requirements for a Generator Owner that has received a request for interconnection. The lack of such requirements for a Generator Owner’s Facility could result in gaps.

Therefore, the SDT proposes that “Generator Owner” be added to the Applicability section of FAC-001-0. It further proposes the addition of Requirement 4 and a corresponding measure:

**R4.** Generator Owner that receives an interconnection request for its facility shall, within 45 days of such a request, be required to comply with requirements R1, R2, and R3 for the facility for which it received the interconnection request.

**M4.** The Generator Owner that receives an interconnection request for its facility shall make available (to its Compliance Monitor) for inspection evidence that it met the requirements stated in Reliability Standard FAC-001-0 R4.

These proposed standard changes are redlined in Attachment 1.

Note that FAC-001-0 has been assigned for modification under Project 2010-02, but as of March 4, 2011, no activity has yet taken place on that project.

- 2. Add “Generator Owner” to the Applicability section of FAC-003-2 and modify the requirements and measures to include Generator Owner.**

The proposed FAC-003-2 currently applies to Transmission Owners and addresses the need to maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW.

A Transmission Vegetation Management Plan is used to ensure the reliable operation of electric transmission systems and prevent vegetation-related outages. Because generator-owned Facilities may include electric transmission, FAC-003-2 should be applicable to

Generator Owners. Requiring Generator Owners to adhere to the requirements in this standard will ensure that Facilities like the generator interconnecting line lead are inspected as defined in the Transmission Vegetation Management Plan and that all vegetation that breaches specified clearances is properly trimmed. This change in applicability will also ensure the proper reporting of vegetation-related outages to the appropriate Regional Reliability Organizations.

The SDT proposes that “Generator Owner” is added to all requirements and measures that mention the Transmission Owner. These proposed changes are outlined in Attachment 2.

The SDT recognizes that if these standard changes are made, changes to the accompanying FAC-003-2 definition modifications may also be needed. As noted above, such changes will be considered after informal comments are received.

**3. Follow the Project 2010-17—Definition of Bulk Electric System and ensure that the responsibility for generator interconnecting line leads is appropriately and clearly assigned to Generator Owners and Operators.**

The Project 2010-07 SDT recognizes that it cannot control the work of the SDT working on the definition of Bulk Electric System. Still, the Project 2010-07 SDT is hopeful that changes made to this definition will be instrumental in covering the reliability gap with respect to generator requirements at the transmission interface. At this stage in the definition’s development, Project 2010-17’s [concept paper](#) has a section on Proposed BES Criteria, and it includes the following:

3. *Generation plants (including GSU transformers and the associated generator interconnecting line lead(s)) with aggregate capacity greater than 75 MVA (gross nameplate rating) directly connected via a step-up transformer(s) to Transmission Facilities operated at voltages of 100 kV or above;*

The Project 2010-07 SDT recognizes that this concept paper is a working draft and is in no way enforceable at this time; still, the Project 2010-07 SDT is hopeful that the BES team is moving in a direction that will be complementary to its own work.

The proposed changes listed above mark a significant decrease in changes originally proposed by the GOTO Ad Hoc Group in its [Final Report](#). In particular, clarifications to the definition of Bulk Electric System eliminate the need for the GOTO Ad Hoc Group’s suggestions to include a reference to the proposed new term “Generator Interconnection Facility” in the following standards referenced in the GOTO Ad Hoc Group Final Report:

- BAL-005-0.1b
- CIP-002-1
- EOP-001-0
- EOP-004-1
- FAC-008-1
- FAC-009-1

- IRO-005-2
- MOD-010-0
- MOD-012-0
- PRC-004-1
- PRC-005-1
- TOP-002-2
- TOP-003-0
- VAR-001-1
- VAR-002-1

All of the standards listed above already apply to the Generator Owner or Generator Operator,<sup>5</sup> so as long as generator-owned Facilities like generator interconnection facilities are appropriately assigned to the responsibility of those entities with changes to the definition of Bulk Electric System, there should be no need to highlight the inclusion of “Generator Interconnection Facility” with language changes in those standards.

Other proposed changes are also unnecessary. In **EOP-003-1**, the GOTO Ad Hoc Group had originally proposed that Generator Operators be added to the requirement that requires Transmission Operators and Balancing Authorities to coordinate automatic load-shedding throughout their areas. The SDT determined that this addition was unnecessary because PRC-001 already includes the requirement that Transmission Operators coordinate their UFLS programs with underfrequency isolation of generating units, which infers that Generator Operators need to provide their underfrequency settings to their respective Transmission Operator. Further, Generator Operators should not be involved in the high-level coordination that this standard requires.

In **EOP-008-0**, the proposed reference to the Generator Interconnection Operational Interface can be eliminated because the proposed term was meant to consist of Elements and Facilities rated at 100 kV and above, which the team has acknowledged are transmission.

In the cases of **PER-001-0** and **PER-002-0**, the SDT believes that additional requirements for training of Generator Owner and Generator Operator personnel should be addressed in a future project. In FERC Order 693, a directive applied “to generator operator personnel at a centrally-located dispatch center who receive direction and then develop specific dispatch instructions for plant operators under their control.” FERC directed that those Generator Operator personnel receive formal training of the nature provided to system operators under PER-005-1. FERC Order 742 confirms that the Commission has “not modified the scope of applicability of the Order 693 directive regarding generator operator training.”

The SDT has also considered proposing further modifications to **PRC-001-2** to ensure coordination of protection system information among Generator Operators and Transmission Operators and to standards **TOP-001-2**, and **TOP-003-2** (all of which are currently under development) to ensure that coordination of information among Generator Operators and Transmission Operators. The SDT has consulted with the members of the Project 2007-03—

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<sup>5</sup> Many have also changed significantly since the GOTO Ad Hoc Group’s review.  
 Project 2010-07: Generator Requirements at the Transmission Interface  
 White Paper Proposal for Informal Comment  
 March 2011

Real-time Operations SDT and believes that the necessary level of coordination (including for Special Protection Systems) is covered by the requirements in the proposed new **TOP-003-2**.

In **TOP-004-2**, the GOTO Ad Hoc Group's addition of R7 (requiring the Generator Operator to operate its generator interconnection facility within its applicable ratings) is not needed because existing TOP and IRO standards require entities to operate within, or to mitigate, SOLs and IROLs at the direction of the TOP and RC.

The proposed addition of R5 to **TOP-008-1** is also unnecessary because it will be covered in the data specifications of **TOP-003-2**, R1. (TOP-008 is being retired.)

### **Summary and Discussion of Other Solutions**

Again, the purpose of this project is to clearly identify the appropriate generation Facilities and the standards requirements that should apply to such generation Facilities to ensure that the reliability of the Bulk Electric System is maintained. The SDT recognizes that its work alone may not eliminate all reliability gaps with respect to generator-owned Facilities like generator interconnection facilities. As noted above, Project 2010-17—Definition of Bulk Electric System may have an enormous impact on the work of this SDT. We are confident that these changes we have proposed to a small number of standards, in coordination with changes to the Bulk Electric System definition, can achieve the necessary reliability, but we also acknowledge that many entities have taken advantage of solutions outside the standards process that have achieved the same effect.

On April 20, 2010, NERC Compliance published a [Public Bulletin](#) to provide guidance for situations like this, in which entities delegate reliability tasks to a third-party entity. In this bulletin, NERC Compliance emphasizes that while a registered entity may not delegate its responsibility for ensuring that a task is completed, it may delegate the performance of a task to another entity.

As is explained in the bulletin, compliance responsibility for applicable NERC Reliability Standard requirements and accountability for violations thereof may be achieved through several means, including the following:

1. **By Individual:** an entity is registered on the NERC Compliance Registry and such registered entity assumes full compliance responsibility and accountability; or
2. **By Written Contract:** parties enter into written agreement whereby:
  - a. A registered entity delegates the performance of some or all functional activities to a third party that is not a registered entity, and the registered entity retains full compliance responsibility and violation accountability; or
  - b. A registered entity delegates the performance of some or all of the functional activities to a third party, and the third party accepts full compliance responsibility for the specific functions it performs and violation accountability. In this case, there may be individual, concurrent or joint registration of the entities, depending on the nature of the contractual relationship and, in any event, only the registered entity would be held responsible or accountable by a Regional Entity or NERC; or

3. **By Joint Registration Organization (JRO):** each party is registered and is required to clearly identify and allocate compliance responsibility and violation accountability for their respective functions under applicable NERC Reliability Standard requirements.

Because the standards efforts outlined here will not take effect for a year or more, Generator Owners and Generator Operators that are concerned about their registration status should explore options like those explained above and in further detail in NERC Compliance Bulletin 2010-004.

The Project 2010-07 SDT will continue with the efforts outlined above, but will modify its proposal and ultimate actions based on feedback from the industry.

## Standard FAC-001-0 — Facility Connection Requirements

## A. Introduction

1. **Title:** Facility Connection Requirements
2. **Number:** FAC-001-0
3. **Purpose:** To avoid adverse impacts on reliability, ~~Transmission-Bulk Electric System Facility O~~wners must establish facility connection and performance requirements.
4. **Applicability:**
  - ~~4.1.~~ 4.1. Transmission Owner
  - ~~4.1.4.2.~~ 4.1.4.2. Generator Owner
5. **Effective Date:** April 1, 2005

*Note from the Project 2010-07 SDT: The redline changes included in this document are the work of the Project 2010-07 SDT and are provided as a companion to the team's White Paper; the aim is to provide an example to convey the direction of our proposal. This is not intended to be a comprehensive rewrite of the standard.*

## 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
- 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.

## Standard FAC-001-0 — Facility Connection Requirements

- 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, the Regional Reliability Organization, and NERC on request (five business days).

**R4.** Generator Owner that receives an interconnection request for its facility shall, within 45 days of such a request, be required to comply with requirements R1, R2, and R3 for the facility for which it received the interconnection request.

~~R3.~~

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#### 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.

**M2.** The Transmission Owner shall make available (to its Compliance Monitor) for inspection evidence that it met all requirements stated in Reliability Standard FAC-001-0\_R2.

**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.

~~M3-M4.~~ The Generator Owner that receives an interconnection request for its facility shall make available (to its Compliance Monitor) for inspection evidence that it met the requirements stated in Reliability Standard FAC-001-0\_R4.

#### 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

**Standard FAC-001-0 — Facility Connection Requirements**

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
0	April 1, 2005	Effective Date	New



**Standard Development Timeline**

*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**

1. SC approved SAR for initial posting (January 11, 2007).
2. SAR posted for comment (January 15–February 14, 2007).
3. SAR posted for comment (April 10–May 9, 2007).
4. SC authorized moving the SAR forward to standard development (June 27, 2007).
5. First draft of proposed standard posted (October 27, 2008–November 25, 2008).
6. Second draft of revised standard posted (September 10, 20–October 24, 2009).
7. Third draft of revised standard posted (March 1, 2010–March 31, 2010).
8. Forth draft of revised standard posted (June 17, 2010–July 17, 2010).

**Note from the Project 2010-07 SDT:**

*The redline changes included in this document are the work of the Project 2010-07 SDT and are provided as a companion to the team's White Paper; the aim is to provide an example to convey the direction of our proposal. This is not intended to be a comprehensive rewrite of the standard. Any formal standard revision would require coordination with the work of the drafting team currently revising FAC-003-2 under Project 2007-07.*

**Proposed Action Plan and Description of Current Draft**

This is the third posting of the proposed revisions to the standard in accordance with Results-Based Criteria and the fifth draft overall.

**Future Development Plan**

<b>Anticipated Actions</b>	<b>Anticipated Date</b>
Recirculation ballot of standards.	January 2011
Receive BOT approval	February 2011

**Effective Dates**

First calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval is required.

Exceptions:

A line operated below 200kV, designated by the Planning Coordinator as an element of an IROL or as a Major WECC transfer path, becomes subject to this standard 12 months after the date the Planning Coordinator or WECC initially designates the line as being subject to this standard.

An existing transmission line operated at 200kV or higher that is newly acquired by an asset owner and was not previously subject to this standard, becomes subject to this standard 12 months after the acquisition date of the line.

## Version History

Version	Date	Action	Change Tracking
1	TBA	<ol style="list-style-type: none"> <li>1. Added “Standard Development Roadmap.”</li> <li>2. Changed “60” to “Sixty” in section A, 5.2.</li> <li>3. Added “Proposed Effective Date: April 7, 2006” to footer.</li> <li>4. Added “Draft 3: November 17, 2005” to footer.</li> </ol>	01/20/06
1	April 4, 2007	Regulatory Approval — Effective Date	New
2			

### Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary. When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.*

#### **Right-of-Way (ROW)**

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria.

The current glossary definition of this NERC term is modified to address the issues set forth in Paragraph 734 of FERC Order 693.

#### **Vegetation Inspection**

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.

Current definition of Vegetation Inspection:  
The systematic examination of a transmission corridor to document vegetation conditions.

## Introduction

- 1. Title:** Transmission Vegetation Management
- 2. Number:** FAC-003-2
- 3. Objectives:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

## 4. Applicability

### 4.1. Functional Entities:

Transmission Owners

[Generator Owners](#)

- 4.2. Facilities:** Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal<sup>1</sup>, state, provincial, public, private, or tribal entities:

- 4.2.1.** Overhead transmission lines operated at 200kV or higher.
- 4.2.2.** Overhead transmission lines operated below 200kV having been identified as included in the definition of an Interconnection Reliability Operating Limit (IROL) under NERC Standard FAC-014 by the Planning Coordinator.
- 4.2.3.** Overhead transmission lines operated below 200 kV having been identified as included in the definition of one of the *Major WECC Transfer Paths in the Bulk Electric System*.
- 4.2.4.** This standard applies to overhead transmission lines identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

### Rationale

-The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) The standard was written for Transmission Owners. Rolling the excluded areas into this standard will bring GO and DP into the standard, even though NERC has an initiative in place to address this bigger registry issue. 4) Specifically addressing the areas where the standard applies or doesn't makes the standard stronger as it relates to clarity.

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<sup>1</sup> EPAAct 2005 section 1211c: “Access approvals by Federal agencies”.

**4.3. Enforcement:** *The reliability obligations of the applicable entities and facilities are contained within the technical requirements of this standard. [Straw proposal]*

## 5. Background:

This NERC Vegetation Management Standard (“Standard”) uses a defense-in-depth approach to improve the reliability of the electric Transmission System by preventing those vegetation related outages that could lead to Cascading. This Standard is not intended to address non-preventable outages such as those due to vegetation fall-ins or blow-ins from outside the Right-of-Way, vandalism, human activities and acts of nature. Operating experience indicates that trees that have grown out of specification have contributed to Cascading, especially under heavy electrical loading conditions.

With a defense-in-depth strategy, this Standard utilizes three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

- a) Performance-based — defines a particular reliability objective or outcome to be achieved.
- b) Risk-based — preventive requirements to reduce the risks of failure to acceptable tolerance levels.
- c) Competency-based — defines a minimum capability an entity needs to have to demonstrate it is able to perform its designated reliability functions.

The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard. For this Standard, the requirements have been developed as follows:

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

Thus the various requirements associated with a successful vegetation program could be viewed as using R1, R2 and R3 as first levels of defense; while R4 could be a subsequent or final level of defense. R6 depending on the particular vegetation approach may be either an initial defense barrier or a final defense barrier.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the Standard requirements for applicable lines on any kind of land or easement,

whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the Standard the term “public lands” includes municipal lands, village lands, city lands, and a host of other governmental entities.

This Standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This Standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this Standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of multiple line failures and Cascading. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are statistically intermittent. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this Standard’s emphasis is on vegetation grow-ins.

## Requirements and Measures

**R1.** Each Transmission Owner [and Generator Owner](#) shall manage vegetation to prevent encroachments of the types shown below, into the Minimum Vegetation Clearance Distance (MVCD) of any of its applicable line(s) identified as an element of an Interconnection Reliability Operating Limit (IROL) in the planning horizon by the Planning Coordinator; or Major Western Electricity Coordinating Council (WECC) transfer path(s); operating within its Rating and all Rated Electrical Operating Conditions.<sup>2</sup>

1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,
2. An encroachment due to a fall-in from inside the Right-of-Way (ROW) that caused a vegetation-related Sustained Outage,
3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,
4. An encroachment due to a grow-in that caused a vegetation-related Sustained Outage.  
*[VRF – High] [Time Horizon – Real-time]*

### Rationale

The MVCD is a calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages. The distances in Table 2 were derived using a proven transmission design method. The types of failure to manage vegetation are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a TO's vegetation maintenance program since the encroachments listed require different and increasing levels of skills and knowledge and thus constitute a logical progression of how well, or poorly, a TO manages vegetation relative to this Requirement.

**M1.** Each Transmission Owner [and Generator Owner](#) has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments.

If a later confirmation of a Fault by the Transmission Owner [or Generator Owner](#) shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

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<sup>2</sup> This requirement does not apply to circumstances that are beyond the control of a Transmission Owner [or Generator Owner](#) subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined ~~either~~ by the Transmission Owner, [the Generator Owner](#), or an applicable regulatory body, ice storms, and floods ~~and~~; human or animal activity such as logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.



Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period. (R1)

**R2.** Each Transmission Owner [and Generator Owner](#) shall manage vegetation to prevent encroachments of the types shown below, into the MVCD of any of its applicable line(s) that is not an element of an IROL; or Major WECC transfer path; operating within its Rating and all Rated Electrical Operating Conditions.<sup>2</sup>

1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,
3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,
4. An encroachment due to a grow-in that caused a vegetation-related Sustained Outage.

*[VRF – Medium] [Time Horizon – Real-time]*

**M2.** Each Transmission Owner [and Generator Owner](#) has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments.

If a later confirmation of a Fault by the Transmission Owner [or Generator Owner](#) shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period. (R2)

#### **Rationale**

The MVCD is a calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages. The distances in Table 2 were derived using a proven transmission design method. The types of failure to manage vegetation are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a TO's vegetation maintenance program since the encroachments listed require different and increasing levels of skills and knowledge and thus constitute a logical progression of how well, or poorly, a TO manages vegetation relative to this Requirement.

**R3.** Each Transmission Owner [and Generator Owner](#) shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable transmission lines that include(s) the following:

- 3.1** Accounts for the movement of applicable transmission line conductors under their Facility Rating and all Rated Electrical Operating Conditions;
- 3.2** Accounts for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

**Rationale**

The documentation provides a basis for evaluating the competency of the Transmission Owner’s vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the Transmission Owner avoids vegetation-to-wire conflicts under all Rated Electrical Operating Conditions. See Figure 1 for an illustration of possible conductor locations.

*[VRF – Lower] [Time Horizon – Long Term Planning]*

**M3.** The maintenance strategies or procedures or processes or specifications provided demonstrate that the Transmission Owner [or Generator Owner](#) can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

**R4.** Each Transmission Owner [and Generator Owner](#), without any intentional time delay, shall notify the control center holding switching authority for the associated applicable transmission line when the Transmission Owner [or Generator Owner](#) has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment.

**Rationale**

To ensure expeditious communication between the Transmission Owner and the control center when a critical situation is confirmed.

*[VRF – Medium] [Time Horizon – Real-time]*

**M4.** Each Transmission Owner [and Generator Owner](#) that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

- R5.** When a Transmission Owner [or Generator Owner](#) is constrained from performing vegetation work, and the constraint may lead to a vegetation encroachment into the MVCD of its applicable transmission lines prior to the implementation of the next annual work plan then the Transmission Owner [or Generator Owner](#) shall take corrective action to ensure continued vegetation management to prevent encroachments.

*[VRF – Medium] [Time Horizon – Operations Planning]*

#### **Rationale**

Legal actions and other events may occur which result in constraints that prevent the Transmission Owner from performing planned vegetation maintenance work. In cases where the transmission line is put at potential risk due to constraints, the intent is for the Transmission Owner to put interim measures in place, rather than do nothing. The corrective action process is intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

- M5.** Each Transmission Owner [and Generator Owner](#) has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, and evidence that a line was de-energized. (R5)

- R6.** Each Transmission Owner [and Generator Owner](#) shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 months between inspections on the same ROW.<sup>3</sup>

*[VRF – Medium] [Time Horizon – Operations Planning]*

- M6.** Each Transmission Owner [and Generator Owner](#) has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable

#### **Rationale**

Inspections are used by Transmission Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

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<sup>3</sup> When the Transmission Owner [or Generator Owner](#) is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the [Transmission Owner or Generator Owner](#) is granted a time extension that is equivalent to the duration of the time the [Transmission Owner or Generator Owner](#) was prevented from performing the Vegetation Inspection.

transmission lines at least once per calendar year but with no more than 18 months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

**R7.** Each Transmission Owner [and Generator Owner](#) shall complete 100% of its annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not put the transmission system at risk of a vegetation encroachment) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include:

**Rationale**

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. An annual vegetation work plan allows for work to be modified for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that the changes do not violate the encroachment within the MVCD.

- Change in expected growth rate/ environmental factors
- Circumstances that are beyond the control of a Transmission Owner [or Generator Owner](#)<sup>4</sup>
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Emerging technologies

*[VRF – Medium] [Time Horizon – Operations Planning]*

**M7.** Each Transmission Owner [and Generator Owner](#) has evidence that it completed its annual vegetation work plan. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (including modifications if any), dated work orders, dated invoices, or dated inspection records. (R7)

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<sup>4</sup> Circumstances that are beyond the control of a Transmission Owner [or Generator Owner](#) include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, major storms as defined either by the TO [or GO](#) or an applicable regulatory body, ice storms, and floods; arboricultural, horticultural or agricultural activities.

## Compliance

### **Compliance Enforcement Authority**

- Regional Entity

### **Compliance Monitoring and Enforcement Processes:**

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints
- Periodic Data Submittals

### **Evidence Retention**

The Transmission Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, Measures M1, M2, M3, M5, M6 and M7 for three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

### **Additional Compliance Information**

**Periodic Data Submittal:** The Transmission Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable transmission lines determined by the Transmission Owner to have been caused by vegetation, except as excluded in footnote 2, which includes as a minimum, the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the Transmission Owner.

A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable transmission lines, that are identified as an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;

- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable transmission lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable transmission lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable transmission lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable transmission lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable transmission lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable transmission lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

The Regional Entity will report the outage information provided by Transmission Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

Time Horizons, Violation Risk Factors, and Violation Severity Levels

Table 1						
R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Real-time	High	The Transmission Owner had an encroachment into the MVCD observed in Real-time, absent a Sustained Outage.	The Transmission Owner had an encroachment into the MVCD due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage.	The Transmission Owner had an encroachment into the MVCD due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage.	The Transmission Owner had an encroachment into the MVCD due to a grow-in that caused a vegetation-related Sustained Outage.
R2	Real-time	Medium	The Transmission Owner had an encroachment into the MVCD observed in Real-time, absent a Sustained Outage.	The Transmission Owner had an encroachment into the MVCD due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage.	The Transmission Owner had an encroachment into the MVCD due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage.	The Transmission Owner had an encroachment into the MVCD due to a grow-in that caused a vegetation-related Sustained Outage.
R3	Long-Term Planning	Lower		The Transmission Owner has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between	The Transmission Owner has maintenance strategies or documented procedures or processes or specifications but has not accounted for the	The Transmission Owner does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the

				vegetation growth rates, vegetation control methods, and inspection frequency, for the Transmission Owner's applicable lines.	movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the Transmission Owner's applicable lines.	encroachment of vegetation into the MVCD, for the Transmission Owner's applicable lines.
R4	Real-time	Medium			The Transmission Owner experienced a confirmed vegetation threat and notified the control center holding switching authority for that transmission line, but there was intentional delay in that notification.	The Transmission Owner experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that transmission line.
R5	Operations Planning	Medium				The Transmission Owner did not take corrective action when it was constrained from performing planned vegetation work where a transmission line was put at potential risk.
R6	Operations Planning	Medium	The Transmission Owner failed to inspect 5% or less of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or	The Transmission Owner failed to inspect more than 5% up to and including 10% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The Transmission Owner failed to inspect more than 10% up to and including 15% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The Transmission Owner failed to inspect more than 15% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).



			kilometers, etc.)			
R7	Operations Planning	Medium	The Transmission Owner failed to complete up to 5% of its annual vegetation work plan (including modifications if any).	The Transmission Owner failed to complete more than 5% and up to 10% of its annual vegetation work plan (including modifications if any).	The Transmission Owner failed to complete more than 10% and up to 15% of its annual vegetation work plan (including modifications if any).	The Transmission Owner failed to complete more than 15% of its annual vegetation work plan (including modifications if any).

**Variations**  
None.

**Interpretations**  
None.

## Guideline and Technical Basis

### Requirements R1 and R2:

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the prevention of vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each Transmission Owner to manage vegetation to prevent encroachment within the Minimum Vegetation Clearance Distance (“MVCD”) of transmission lines. R1 is applicable to lines “identified as an element of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path (operating within Rating and Rated Electrical Operating Conditions) to avoid a Sustained Outage”. R2 applies to all other applicable lines that are not an element of an IROL or Major WECC Transfer Path.

The separation of applicability (between R1 and R2) recognizes that an encroachment into the MVCD of an IROL or Major WECC Transfer Path transmission line is a greater risk to the electric transmission system. Applicable lines that are not an element of an IROL or Major WECC Transfer Path are required to be clear of vegetation but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

These requirements (R1 and R2) state that if vegetation encroaches within the distances in Table 1 in Appendix 1 of this supplemental Transmission Vegetation Management Standard FAC-003-2 Technical Reference document, it is in violation of the standard. Table 2 tabulates the distances necessary to prevent spark-over based on the Gallet equations as described more fully in Appendix 1 below.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating (potentially in violation of other standards), the occurrence of a clearance encroachment may occur. For example, emergency actions taken by a Transmission Operator or Reliability Coordinator to protect an Interconnection may cause the transmission line to sag more and come closer to vegetation, potentially causing an outage. Such vegetation-related outages are not a violation of these requirements.

Evidence of violation of Requirement R1 and R2 include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to blowing together of applicable lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. If an investigation of a Fault by a Transmission Owner confirms that a vegetation encroachment within the MVCD occurred, then it shall be considered the equivalent of a Real-time observation.

With this approach, the VSLs were defined such that they directly correlate to the severity of a failure of a Transmission Owner to manage vegetation and to the corresponding performance level of the Transmission Owner’s vegetation program’s ability to meet the goal of “preventing a Sustained Outage that could lead to Cascading.” Thus violation severity increases with a Transmission Owner’s inability to meet this goal and its potential of leading to a Cascading

event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example, a limb may only partially break and intermittently contact a conductor. Such events are considered to be a single vegetation-related Sustained Outage under the Standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will prevent transmission outages.

**Requirement R3:**

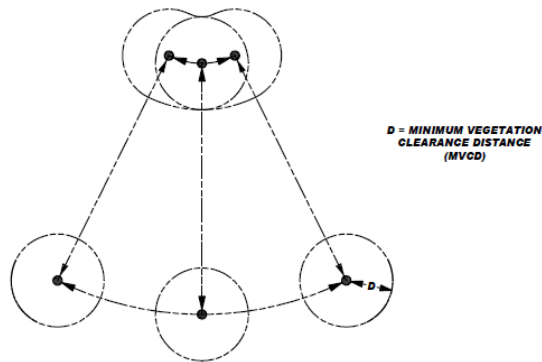
Requirement R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, a Transmission Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the Transmission Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the Transmission System. The approach provides the basis for evaluating the intent, allocation of appropriate resources and the competency of the Transmission Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the Transmission Owner must be able to state what its approach is and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach a Transmission Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the Transmission Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing as a reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below.



**Figure 1**

Cross-section view of a single conductor at a given point along the span showing six possible conductor positions due to movement resulting from thermal and mechanical loading.

**Requirement R4:**

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the Transmission Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of a Transmission Owner’s employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The Transmission Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or positioning the system in recognition of the increasing risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some Transmission Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

**Requirement R5:**

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the Transmission Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the Transmission Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the Transmission Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the Transmission Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the Transmission Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the Transmission Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for each location.
- In developing the specific action to mitigate the potential risk to the transmission line the Transmission Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The Transmission Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

**Requirement R6:**

R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections that fits general industry practice. In addition, the fact that Vegetation Inspections can be performed in conjunction with general line inspections further facilitates a Transmission Owner's ability to meet this requirement. However, the Transmission Owner may determine that more frequent inspections are needed to maintain reliability levels, dependent upon such factors as anticipated growth rates of the local vegetation, length of the growing season for the geographical area, limited ROW width, and rainfall amounts. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSL for Requirement R6 has VSL categories ranked by the percentage of the required ROW inspections completed. To calculate the percentage of inspection completion, the Transmission Owner may choose units such as: line miles or kilometers, circuit miles or kilometers, pole line miles, ROW miles, etc.

For example, when a Transmission Owner operates 2,000 miles of 230 kV transmission lines this Transmission Owner will be responsible for inspecting all 2,000 miles of 230 kV transmission lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be  $100/2000 = 0.05$  or 5%. The "Low VSL" for R6 would apply in this example.

**Requirement R7:**

R7 is a risk-based requirement. The Transmission Owner is required to implement an annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a "span-by-span", or even a "line-by-line" detailed description of all work to be performed. It is only intended to require that the Transmission Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

The ability to modify the work plan allows the Transmission Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the Transmission Owner's system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan. Modifications to the annual work plan must always ensure the reliability of the electric Transmission system.

In general, the vegetation management maintenance approach should use the full extent of the Transmission Owner's easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental

management in the long term because it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the Transmission Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Transmission Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the Transmission Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.



FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)<sup>5</sup>  
For Alternating Current Voltages

( AC ) Nominal System Voltage (kV)	( AC ) Maximum System Voltage (kV)	MVCD feet (meters) sea level	MVCD feet (meters) 3,000ft (914.4m)	MVCD feet (meters) 4,000ft (1219.2m)	MVCD feet (meters) 5,000ft (1524m)	MVCD feet (meters) 6,000ft (1828.8m)	MVCD feet (meters) 7,000ft (2133.6m)	MVCD feet (meters) 8,000ft (2438.4m)	MVCD feet (meters) 9,000ft (2743.2m)	MVCD feet (meters) 10,000ft (3048m)	MVCD feet (meters) 11,000ft (3352.8m)
765	800	8.06ft (2.46m)	8.89ft (2.71m)	9.17ft (2.80m)	9.45ft (2.88m)	9.73ft (2.97m)	10.01ft (3.05m)	10.29ft (3.14m)	10.57ft (3.22m)	10.85ft (3.31m)	11.13ft (3.39m)
500	550	5.06ft (1.54m)	5.66ft (1.73m)	5.86ft (1.79m)	6.07ft (1.85m)	6.28ft (1.91m)	6.49ft (1.98m)	6.7ft (2.04m)	6.92ft (2.11m)	7.13ft (2.17m)	7.35ft (2.24m)
345	362	3.12ft (0.95m)	3.53ft (1.08m)	3.67ft (1.12m)	3.82ft (1.16m)	3.97ft (1.21m)	4.12ft (1.26m)	4.27ft (1.30m)	4.43ft (1.35m)	4.58ft (1.40m)	4.74ft (1.44m)
230	242	2.97ft (0.91m)	3.36ft (1.02m)	3.49ft (1.06m)	3.63ft (1.11m)	3.78ft (1.15m)	3.92ft (1.19m)	4.07ft (1.24m)	4.22ft (1.29m)	4.37ft (1.33m)	4.53ft (1.38m)
161*	169	2ft (0.61m)	2.28ft (0.69m)	2.38ft (0.73m)	2.48ft (0.76m)	2.58ft (0.79m)	2.69ft (0.82m)	2.8ft (0.85m)	2.91ft (0.89m)	3.03ft (0.92m)	3.14ft (0.96m)
138*	145	1.7ft (0.52m)	1.94ft (0.59m)	2.03ft (0.62m)	2.12ft (0.65m)	2.21ft (0.67m)	2.3ft (0.70m)	2.4ft (0.73m)	2.49ft (0.76m)	2.59ft (0.79m)	2.7ft (0.82m)
115*	121	1.41ft (0.43m)	1.61ft (0.49m)	1.68ft (0.51m)	1.75ft (0.53m)	1.83ft (0.56m)	1.91ft (0.58m)	1.99ft (0.61m)	2.07ft (0.63m)	2.16ft (0.66m)	2.25ft (0.69m)
88*	100	1.15ft (0.35m)	1.32ft (0.40m)	1.38ft (0.42m)	1.44ft (0.44m)	1.5ft (0.46m)	1.57ft (0.48m)	1.64ft (0.50m)	1.71ft (0.52m)	1.78ft (0.54m)	1.86ft (0.57m)
69*	72	0.82ft (0.25m)	0.94ft (0.29m)	0.99ft (0.30m)	1.03ft (0.31m)	1.08ft (0.33m)	1.13ft (0.34m)	1.18ft (0.36m)	1.23ft (0.37m)	1.28ft (0.39m)	1.34ft (0.41m)

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above).

<sup>5</sup> The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

**Table 2 (cont.) — Minimum Vegetation Clearance Distances (MVCD)  
For Direct Current Voltages**

( DC ) Nominal Pole to Ground Voltage (kV)	MVCD feet (meters) sea level	MVCD feet (meters) 3,000ft (914.4m) Alt.	MVCD feet (meters) 4,000ft (1219.2m) Alt.	MVCD feet (meters) 5,000ft (1524m) Alt.	MVCD feet (meters) 6,000ft (1828.8m) Alt.	MVCD feet (meters) 7,000ft (2133.6m) Alt.	MVCD feet (meters) 8,000ft (2438.4m) Alt.	MVCD feet (meters) 9,000ft (2743.2m) Alt.	MVCD feet (meters) 10,000ft (3048m) Alt.	MVCD feet (meters) 11,000ft (3352.8m) Alt.
±750	13.92ft (4.24m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.9ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.07ft (3.07m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	7.89ft (2.40m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	4.78ft (1.46m)	5.35ft (1.63m)	5.55ft (1.69m)	5.75ft (1.75m)	5.95ft (1.81m)	6.15ft (1.87m)	6.36ft (1.94m)	6.57ft (2.00m)	6.77ft (2.06m)	6.98ft (2.13m)
±250	3.43ft (1.05m)	4.02ft (1.23m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5ft (1.52m)	5.17ft (1.58m)

Notes:

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet Equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 uses the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-01 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 5 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 7 would have to be used. Table 7 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines, as such, are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line is approximately 2.0 per unit. This value is a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 242 kV and below is considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at 362 kV and above a transient over-voltage factor of 1.4 per unit is considered a realistic maximum.

The Gallet Equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet Equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America [1].

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

While EPRI is currently trying to establish empirical data for spark-over distances to live vegetation, there are no spark-over formulas currently derived expressly for vegetation to conductor minimum distances. Therefore the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations using various transient overvoltage values.

**Comparison of spark-over distances computed using Gallet wet equations  
vs.  
IEEE 516-2003 MAID distances  
using various transient over-voltage factors**

( AC ) Nom System Voltage (kV)	( AC ) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 feet	Table 5 IEEE 516 MAID (ft) @ Alt. 3000 feet
765	800	1.4	8.89	8.65
500	550	1.4	5.65	4.92
345	362	1.4	3.52	3.13
230	242	2.0	3.35	2.8
115	121	2.0	1.6	1.4

( AC ) Nom System Voltage (kV)	( AC ) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 feet	Table 5 (historical maximums) IEEE 516 MAID (ft) @ Alt. 3000 feet
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

<b>( AC ) Nom System Voltage (kV)</b>	<b>( AC ) Max System Voltage (kV)</b>	<b>Transient Over-voltage Factor (T)</b>	<b>Clearance (ft.) Gallet (wet) @ Alt. 3000 feet</b>	<b>Table 7 IEEE 516 MAID (ft) @ Alt. 3000 feet</b>
765	800	2.5	20.25	20.4
500	550	3.0	15.02	14.7
345	362	3.5	10.42	9.44
230	242	3.5	6.32	5.14
115	121	3.5	2.90	2.45



NORTH AMERICAN ELECTRIC  
RELIABILITY CORPORATION

## Standards Announcement

Project 2010-07 Generator Requirements at the Transmission Interface  
Informal Comment Period Open  
March 4 – April 4, 2011

Now available at: [http://www.nerc.com/filez/standards/Project2010-07\\_GOTO\\_Project.html](http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html).

### Informal Comment Period Open through 8 p.m. Eastern on Monday, April 4, 2011

The Project 2010-07 Generator Requirements at the Transmission Interface drafting team has posted for a 30-day informal comment period, a White Paper on proposed concepts to support the modifications of various standards to clarify the reliability standard responsibilities of Generator Owners and Generator Operators at the interface to the interconnected grid. The White Paper, along with proposed redlined changes to standards that would be affected by the proposal, have been posted on the project Web page at [http://www.nerc.com/filez/standards/Project2010-07\\_GOTO\\_Project.html](http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html).

### Instructions

The drafting team welcomes any constructive feedback for improving its proposal to ensure that the responsibilities of Generator Owners and Generator Operators at the interface to the interconnected grid are covered under NERC's Reliability Standards. Consider using the following questions to focus your comments:

- How can the proposal outlined in the White Paper be improved? Is the drafting team heading in the right direction?
- The drafting team has chosen to use informal means of receiving industry feedback (webinars, presentations before industry stakeholder groups, etc.) prior to expending valuable industry resources to develop specific proposals for reliability standard requirements, measures, VSLs, etc. Do you have any further suggestions for seeking industry input before the project moves into a more formal development phase?
- The Ad Hoc group originally proposed the new terms "Generator Interconnection Facility" and "Generator Interconnection Operational Interface" as part of this project. The Project 2010-07 drafting team believes that changes to the definition of Bulk Electric System under Project 2010-17 and modifications to a select group of standards can accomplish the same goal without the need for new definitions. Do you support this approach? If not, please explain.

Please submit comments by e-mail to Mallory Huggins at [mallory.huggins@nerc.net](mailto:mallory.huggins@nerc.net).

### Next Steps

The drafting team will consider the input received on the concept White Paper as it continues its work.

## Project Background

Significant industry concern exists regarding the application of Transmission Owner and Transmission Operator requirements, and more specifically, the registration of Generator Owners and Generator Operators as Transmission Owners and Transmission Operators based on the facilities that connect the generators to the interconnected grid. NERC formed the Generator Requirements at the Transmission Interface Ad Hoc Group in 2009 to analyze and make recommendations for establishing general criteria for determining whether Generator Owners and Generator Operators should be registered for Transmission Owner and Transmission Operator requirements in NERC's Reliability Standards. The Ad Hoc Group developed a report evaluating the issues and proposing a number of changes to add clarity on the requirements for generator interconnection facilities. Using feedback from the industry, NERC, and FERC, the Project 2010-07 drafting team significantly revised the Ad Hoc Group's original proposal and offers a refined proposal here.

## Standards Process

The [Standard Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,  
Standards Process Administrator, at [monica.benson@nerc.net](mailto:monica.benson@nerc.net) or at 404-446-2560.

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## Summary

The drafting team welcomes any constructive feedback for improving its proposal to ensure that the responsibilities of Generator Owners and Generator Operators at the interface to the interconnected grid are covered under NERC's Reliability Standards. Consider using the following questions to focus your comments:

- How can the proposal outlined in the White Paper be improved? Is the drafting team heading in the right direction?
- The drafting team has chosen to use informal means of receiving industry feedback (webinars, presentations before industry stakeholder groups, etc.) prior to expending valuable industry resources to develop specific proposals for reliability standard requirements, measures, VSLs, etc. Do you have any further suggestions for seeking industry input before the project moves into a more formal development phase?
- The Ad Hoc group originally proposed the new terms "Generator Interconnection Facility" and "Generator Interconnection Operational Interface" as part of this project. The Project 2010-07 drafting team believes that changes to the definition of Bulk Electric System under Project 2010-17 and modifications to a select group of standards can accomplish the same goal without the need for new definitions. Do you support this approach? If not, please explain.

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**Connie Lowe, Dominion Resource Services**

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## COMMENTS:

Dominion agrees this is a good overall approach to identify specific TO/TOP requirements associated with a qualifying generator and address an important registration and potential reliability gap.

Minor suggestions include the following:

(1) The timeframe in R4 of 45 days could be increased to at least 90 days before a GO is required to become compliant after it receives an interconnection request.

This additional time will allow proper coordination within other groups that should stay in coordination.

(2) Need clarity in the white paper on page 3, 3rd paragraph that states *“When the transmission Elements and Facilities owned and operated by Generator Owners and Generator Operators are non-network/non-integrated transmission, applying all standards applicable to Transmission Owners and Transmission Operators would have little effect on the overall reliability of the Bulk Electric System when compared to the operation of the equipment that actually produces electricity – the generation equipment itself.”*

This statement seems to make sense when looked at from the GO/GOP perspective. However what happens if the TO owns these transmission elements and facilities? Would the TO be required to adhere to a smaller set of standards or *all* TO/TOP standards for this subset of elements? This matter should be clarified.

### **Dominion has also answered the below questions posed by NERC below.**

• How can the proposal outlined in the White Paper be improved?

Is the drafting team heading in the right direction? **Yes**

• The drafting team has chosen to use informal means of receiving industry feedback (webinars, presentations before industry stakeholder groups, etc.) prior to expending valuable industry resources to develop specific proposals for reliability standard requirements, measures, VSLs, etc. Do you have any further suggestions for seeking industry input before the project moves into a more formal development phase?

• The Ad Hoc group originally proposed the new terms “Generator Interconnection Facility” and “Generator Interconnection Operational Interface” as part of this project. The Project 2010-07 drafting team believes that changes to the definition of Bulk Electric System Under Project 2010-17 and modifications to a select group of standards can accomplish the same goal without the need for new definitions. Do you support this approach? **YES**

If not, please explain.

**Bob Folt, ReliabilityFirst Corporation**

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**COMMENTS:**



Adobe Acrobat  
Document

**Doug Hohlbaugh, FirstEnergy Corp.**  
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330-384-4698

## COMMENTS:

### **Re: Project 2010-07 Generator Requirements at the Transmission Interface Informal Comment Period Ending April 4, 2011**

Mallory Huggins

North American Electric Reliability Corporation

NERC Coordinator, Project 2010-07 Generator Requirements at the Transmission Interface (“GOTO Project”)

FirstEnergy (“FE”) appreciates the opportunity to provide comments on Project 2010 -07 Generator Requirements at the Transmission Interface. FirstEnergy generally supports the Standard Drafting Team’s (“SDT’s”) March 2011 [“White Paper Proposal for Informal Comment”](#) (“White Paper”) and its recommended approach to scale back or eliminate many of the reliability standard revisions previously proposed by the [Ad Hoc team’s Final Report](#). The SDT’s White Paper largely aligns with prior comments offered by FE on the GOTO Project. In comments filed in March 2010 in response to the Ad Hoc team’s work and supported by FE, the ISO RTO Council Standards Review Committee stated as follows:

*These SAR and associated draft standards changes go beyond what is needed to resolve the GO/TOP GOP/TOP registration issue. The only real changes that are needed are to include adding GO and GOP applicability in the FAC-003 standard so that vegetation management can be enforced for lines built to interconnect generators without registering the GO/GOP as a TO/TOP. All additional changes just add confusion and cause significant coordination issues with other draft standard changes. This proposed SAR and associated standards’ modifications does not appear to have been coordinated with any other drafting team. There are many standards and requirements that are in various states of change. For instance, the TOP standards have been significantly modified and are nearing the ballot phase. Coordination needs to occur before these changes are balloted.*

We applaud the drafting team for carefully considering comments submitted by our company and other industry stakeholders.

#### **FE Disagrees with the proposed FAC-001 Changes:**

As the White Paper acknowledges, Generator Owners (“GOs”) and Generator Operators (“GOPs”) “should not be subject to the same level of standards applicable to Transmission Owners and Transmission Operators who own and operate transmission Facilities and Elements that are part of the integrated bulk power system.” Further, the White Paper properly states that subjecting GOs and GOPs to all standards applicable to TOs and TOPs would do little to improve the reliability of the Bulk Electric System (“BES”).

The proposed FAC-001-0 Requirement 4 would impose TO requirements on a GO simply because it “receives an interconnection request for its (transmission) facility.” However, the White Paper is premised on the assumption that GOs that receive interconnection requests are required to allow such interconnection to go forward. The simple fact is that not every transmission facility that is owned by a GO is subject to FERC’s “open access” requirements. FERC’s “open access” requirements apply only if the line is used to provide FERC-jurisdictional transmission service. Many lines are not so used, and therefore a decision to allow a third party to interconnect may lie entirely within the GO’s discretion.

We offer the following suggested revisions to the proposed requirement R4 and the corresponding measure M4:

R4. Generator Owner that is required to or elects to permit an interconnection request for its facility shall make available to the requesting party its facility connection requirements addressing items detailed in Requirement R2 above.

M4. The Generator Owner that is required to or elects to permit an interconnection request for its facility shall make available (to its Compliance Monitor) for inspection evidence that it met the requirements stated in Reliability Standard FAC-001-0 R4.

We appreciate NERC's careful consideration of the comments provided. Should you have any questions or require clarification please do not hesitate to contact me at 330-384-4698.

**Laura Beane, Iberdrola Renewables**

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**COMMENTS:**

Iberdrola Renewables fully supports the recommendations in the “Project 2010-07: Generator Requirements at the Transmission Interface White Paper Proposal”.



**Louis Slade, Dominion**  
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## COMMENTS:

SERC OC Standards Review Group

Comments on Project 2010-07: Generator Requirements at the Transmission Interface

How can the proposal be improved?

1. Make the language clearer on the concept of a GO/GOP interconnection request to an established GO/GOP that has an existing interconnection to the BES. It would be beneficial to include a diagram(s) of interconnection examples.
2. We feel that the GO/GOP should not be forced into registration as a TO/TOP based on having a radial connection (single point of connection) to the BES, provided that the loss of that radial connection is included in the set of study contingencies by the TP and TOP.
3. The team should consider addressing exceptions to the typical (radial connection – single point of connection) generator connections to the BES on a case-by-case basis involving the appropriate parties, such as the GO/GOP/TO/TOP/TP and Regional Entity, rather than creating requirements that apply to all GO/GOPs.

Is the drafting team headed in the right direction?

1. We applaud the team for seeking informal direction from the industry and believe the direction that the team is taking is appropriate.

SERC OC standards Review Group Participation

Gerry Beckerle	Ameren
Jerry Hereen	MEAG
Jim Peterson	Santee Cooper
Shaun Anders	CWLP
Hamid Zakery	Dynegy
Scott McGough	OPC
David Plauck	Calpine
Pat McGovern	GTC
Melinda Montgomery	Entergy
Shardra Scott	Gulf Power
Doug White	NCEMC
JakeMiller	Dynegy
Larry Rodriquez	Entegra Power
Jim Case	Entergy
Ray Phillips	AMEA
John Troha	SERC

***“The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review group only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.”***

**Pat Hervochoon, PSEG**  
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## **COMMENTS:**

### **PSEG Registered Entities Comments on March 2011 White Paper on Generator Requirements at the Transmission Interface**

The PSEG Registered Entities (“REs”) support the work of the *Ad Hoc Group for Generator Requirements at the Transmission Interface* subsequently placed under the aegis of the Standard Development Team (“SDT”) for Project 2010-07. We appreciate this opportunity to provide informal comments on the March 2011 White Paper on Generator Requirements at the Transmission Interface (“White Paper”).

The PSEG REs support the concepts advocated in the White Paper, principally, that:

- Subjecting Generator Owners (“GOs”) or Generation Operators (“GOPs”) to all of the standards applicable to Transmission Owners (“TOs”) or Transmission Operators (“TOPs”) would do little if anything to improve the reliability of the Bulk Electric System;
- The goals of Project 2010-07 can be accomplished by making GOs and GOPs responsible for complying with a limited number of reliability standard requirements, namely certain requirements in FAC-001 and FAC-003; and
- Creating new definitions for generator interconnection facilities and/or interfaces which would be formalized in the NERC Glossary.

The PSEG REs also agree that ability to implement the concepts advocated in the White Paper are inexorably linked to the work of the SDT assigned to Project 2010-17 (Definition of the Bulk Electric System [“BES”]). We therefore recommend the two project teams coordinate their efforts.

We are concerned by the suggestion that the requirements of FAC-001 are applicable within forty-five days of receiving an interconnection request. There are a host of regulatory and commercial activities and assessments that must be completed before the interconnection occurs. In its role as the Regional Transmission Organization, PJM acts as the Transmission Planner and coordinates and evaluates transmission interconnection requests. Furthermore, experience shows that many of these interconnection requests are subsequently withdrawn from the interconnection queues at PJM. Requiring GOs to be fully compliant with FAC-001 within 45 days of the receipt of such request for projects that may never be constructed would not improve the reliability of the BES, but could result in an inefficient use of resources. Therefore, we ask the SDT to consider alternatives to receipt of an interconnection request for triggering FAC-001 applicability to GOs.

With regard to the requirement for GOs related to FAC-003, the PSEG REs support an exemption for transmission facilities on the property of the GO. The SDT has acknowledged this concept in paragraph 4.2.4 of FAC-003-02, but it is unclear exactly which facilities are excluded by this exemption. Since PSEG believes that it is the intent of the SDT to include all

transmission lines on the generating station property as well as the some portion of the transmission line that leaves the station property, we ask the SDT to adopt the approach advocated by the Ad-Hoc Group. Under that approach, the vegetation management standards in FAC-003-02 apply to GOs owning a Generator Interconnection Facility that operates at 200 kV and above, or are otherwise deemed critical to the BES, but provides for an exclusion from FAC-003-02 for Generation Interconnection Facilities that reside within the GOs property line. We also support an exemption for generator lead lines that leave the GO's property but do not exceed two spans (generally one-half mile from the generator property).

The PSEG Companies also acknowledge the efforts of the Electric Power Supply Association ("EPSA") to provide guidance and build consensus on this effort.

**Jay Seitz, U.S. Bureau of Reclamation**

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303-445-2844

**COMMENTS:**

As stated, the purpose of Project 2010-07 is to clearly identify the appropriate generation facilities and the standards requirements that should apply to such generation Facilities to ensure that the reliability of the Bulk electric system is maintained. In pursuit of this purpose judgment and discretion of the Registered Entities should be recognized.

The white paper proposes a role for Generator Owners well outside that of the existing NERC Reliability Functional Model. BES facilities at which an entity may logically request interconnection should be covered by a Transmission Owner and Transmission Operator. We believe many of the concerns raised should be addressed by the registration process rather than push Transmission Owner standards to the Generator Owner.

Specific comments to the white paper follow:

- How can the proposal outlined in the White Paper be improved? Is the drafting team heading in the right direction?

The drafting team can improve its approach by limiting the applicability of those standards in which the drafting team believes a reliability gap may exist for specific type of facilities. This will help to ensure that interconnection requests or vegetation management is applied only to those locations where network or integrated transmission exist.

The drafting team should spend more time on considering the comments provided to the ad hoc team when it developed its final report. Specifically, as stated in the SAR, the drafting team needs to “add particular focus on the operation of the interface point at which operating responsibility shifts from the Generator Operator to the Transmission Operator.” The drafting team appears to have sidestepped the action by what appears to be unilaterally dismissing the work of the ad hoc Team.

The drafting team proposal is not adequately addressing the interface issue in its proposal. The drafting team did recognize that while elements owned by entities who are registered as Generator Owner appear to fit the definition of elements owned by Transmission Owners, the elements need not be subject to the same level of standards applicable to Transmission Owners. The drafting team also recognized that those elements are generally non network or non integrated transmission elements. Simply put they are not used to transmit power other than from the specific Generator Owner. The proposal submitted for comment does not recognize the non network/non integrated transmission nature of the elements when it proposes to apply FAC-001 to Generator Owners. The purpose of FAC-001 is for facilities where network or integrated transmission exists. By applying FAC-001, the Generator Owner “transmission’ type elements,

would be de facto considered network transmission and would then require the Generator Owner to develop interconnection requirements at Generator facilities. Since the Generator Owner now would have a recognized network facility, it would also be subject to FERC Order 888 and be required to develop rates for the use of its facilities.

Finally, the drafting team recognized that the definition of BES would drag certain GO into a TO arena with little if any improvement in reliability of the Bulk Electric System. The drafting team should recognize that if the Generator Owners are in fact required to register as Transmission Owners, the proposed changes to the standards would open the Generator Owner to interconnection requests at other than transmission system voltage levels.

- The drafting team has chosen to use informal means of receiving industry feedback (webinars, presentations before industry stakeholder groups, etc.) prior to expending valuable industry resources to develop specific proposals for reliability standard requirements, measures, VSLs, etc. Do you have any further suggestions for seeking industry input before the project moves into a more formal development phase?

The drafting team should build upon the work of the ad hoc Team which encompasses much of the industry feedback on the subject. The suggestion to modify FAC -001 and FAC-003 do not get to the root of the concerns and do not address the interface issue addressed raised by industry.

- The Ad Hoc group originally proposed the new terms “Generator Interconnection Facility” and “Generator Interconnection Operational Interface” as part of this project. The Project 2010-07 drafting team believes that changes to the definition of Bulk Electric System under Project 2010-17 and modifications to a select group of standards can accomplish the same goal without the need for new definitions. Do you support this approach? If not, please explain.

This action is not supported. The industry spent a great deal of time responding to the white paper drafts which resulted in the recommendation for the new terms. Without defining the interface issues and where they exist, modification of the standards cannot hope to deal with the true reliability issue.

**Cynthia Janka, Arizona Public Service**

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602-250-2028

## **COMMENTS:**

**Chris Cambridge, Engineering Manager and GO GOP Subject Matter Expert submits the following comments on behalf of Arizona Public Service (AZPS).**

The Standards Drafting Team (SDT) for this project is trying to address the Reliability Standards required for a Generator Owner and Operator who has interconnection facilities (referred to as a GOTO). The SDT has provided various approaches for industry comment and AZPS is providing comments on the following two approaches:

Requiring any classification that subjects Generator Owners and Generator Operators to all the standards applicable to Transmission Owners and Transmission Operators would do little, if

anything, to improve the reliability of the Bulk Electric System (see page 3).

To maintain an adequate level of reliability in the Bulk Electric System, a clear delineation of responsibilities and authority at the interface between Generator Owners/Operators and Transmission Owners/Operators is needed. This can be accomplished by properly applying selected standards or specific standard requirements to Generator Owners and Generator Operators (see page 3).

Taking this approach the SDT has done an admirable job of trying to address requirements for this special group of Generator Owners and Operators with generator interconnection facilities without requiring them to comply with all the Transmission Owner and Operator Reliability Standards. However, it does not appear that they have looked at the impact of adding the Generator Owner and Operator to select reliability standards applicable to Transmission Owner and Operator and how this will add additional compliance requirements to the rest of Generator Owners and Operators in the industry. It may be more appropriate to consider the creation of another entity as a Generator Interconnect to clarify the distinction from having full TO/TOP responsibilities. Then the specific requirements could be distinguished between the TO/TOP and GO/GOP.

The SDT has also made the following statements which although understandable do not provide the confidence this is the correct approach in extending the requirements of a Generator Owner and Operator into certain Transmission Owner and Operator standards. The second statement below, as indicated, will considerably alter the SDT previous direction and may limit this approach.

The SDT recognizes that its work alone may not eliminate all reliability gaps with respect to generator-owned Facilities like generator interconnection facilities (see page 7). As noted above, Project 2010-17—Definition of Bulk Electric System may have an enormous impact on the work of this SDT. We are confident that these changes we have proposed to a small number of standards, in coordination with changes to the Bulk Electric System definition, can achieve the necessary reliability (see page 7).

AZPS's ultimate recommendation is to consider adding a new entity to address the specific standards and requirements needed by a Generator Interconnect Facility versus adding additional requirements for a Generator Owner and Operator which are applicable to the Transmission Owner and Operator.

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## **COMMENTS:**

TransAlta Centralia Generation LLC (TransAlta) appreciates the opportunity to provide comments on Project 2010-07 Generator Requirements at the Transmission Interface White Paper Proposal for Informal Comment.

TransAlta strongly encourages the continued progress on Project 2010-07. Completion of this project is important to bring resolution to the industry regarding not only the "go forward approach" but also for those generators that have already been registered as Transmission Owners and Transmission Operators.

TransAlta offers the following specific comments:

1. Overall TransAlta agrees with this more simplified approach. The white paper proposal describes the analysis undertaken by the Standard Drafting Team (STD) to arrive at the shorter list of standard which would require SARs - FAC-001 and FAC-003. We believe this approach is appropriate and logically puts some of the larger issues into forums that are already addressing those issues.

2. One of the recommendations in the white paper proposal is to follow Project 2010-17 Definition of Bulk Electric System and ensure that the responsibility for generator interconnection line leads is appropriately and clearly assigned to Generator Owners and Operators. TransAlta recognizes that Project 2010-017 is likely the more appropriate forum to deal with the definition of Bulk Electric System and the associated impact on the definition of generator interconnection line leads. TransAlta would recommend not only following Project 2010-07, but also active involvement in the project by the SDT to ensure that the responsibility for generator line leads is properly assigned.

3. Under the Section "Summary and Discussion of Other Options" the white paper proposal outlines a number of different options that are available to an entity to manage compliance responsibility. While TransAlta agrees that these options are available, what is important to note is that in many cases these options are difficult, costly and time consuming to implement, resulting in compliance risk for those generators that are registered by a regional entity and NERC for the Transmission Owner and Transmission Operator functions. The compliance risk placed on a generator after registration is one of the reasons we encourage the continued progress on Project 2010-07.

Thank you for considering our comments.



**Denise Koehn, Bonneville Power Administration**  
dekoehn@bpa.gov  
360-418-2533

**COMMENTS:**

Bonneville Power suggests that the following phrase be included:  
"the GO shall coordinate with the TO to ensure that all interconnection facilities are included in the vegetation management plan". This phrasing would leave it up to the GO and TO to determine how to coordinate most effectively.  
We appreciate your consideration of our comment.

**Andy Puzstai, American Transmission Company**  
apusztai@atcllc.com  
(262) 506-6913

### **COMMENTS:**

American Transmission Company LLC (ATC) wishes to thank NERC for providing an opportunity to comment on the NERC Project 2010-07 "Generator Requirements at the Transmission Interface" White Paper as requested in the NERC posting dated March 4, 2011.

ATC reviewed the subject White paper using the recommended focus questions in the NERC posting and has a couple comments. They are summarized in the attached document.

Thanks again for providing an opportunity to comment.

1. How can the proposal outlined in the White Paper be improved? Is the drafting team heading in the right direction?

### **Improvements:**

Next Step #1 - According to FERC Docket #ER10-1117, if a Generator Owner receives a request for service over their facilities; they have 60 days to file a tariff for processing the request for service. ATC believes that the proposed Requirement R4 of FAC-001 should give the Generator Owner 60 days, rather than 45 days, to provide its interconnection requirements.

Next Step #3 – NERC has not clearly defined wind farms to be generating plants. The words, "directly connected via a step-up transformer(s) to Transmission Facilities operated at voltages of 100 kV or above", in the latest Project 2010-17 concept paper may not be interpreted as applicable to wind farms. The generating units of wind farms are typically directly connected to sub-transmission facilities, which in turn are directly connected to Transmission Facilities operated at voltages of 100 kV or above.

**ATC agrees the drafting team is heading in the right direction.**

2. The drafting team has chosen to use informal means of receiving industry feedback (webinars, presentations before industry stakeholder groups, etc.) prior to expending valuable industry resources to develop specific proposals for reliability standard requirements, measures, VSLs, etc. Do you have any further suggestions for seeking industry input before the project moves into a more formal development phase?

**No**

3. The Ad Hoc group originally proposed the new terms "Generator Interconnection Facility" and "Generator Interconnection Operational Interface" as part of this project. The Project 2010-07 drafting team believes that changes to the definition of Bulk Electric System under Project 2010-17 and modifications to a select group of standards can accomplish the same goal without the need for new definitions. Do you support this approach? If not, please explain.

**Yes, ATC supports the approach.**

**John Troha, SERC OC Standards Review Group**  
[jtroha@serc1.org](mailto:jtroha@serc1.org)

## COMMENTS:

SERC OC Standards Review Group

Comments on Project 2010-07: Generator Requirements at the Transmission Interface

How can the proposal be improved?

4. Make the language clearer on the concept of a GO/GOP interconnection request to an established GO/GOP that has an existing interconnection to the BES. It would be beneficial to include a diagram(s) of interconnection examples.
5. We feel that the GO/GOP should not be forced into registration as a TO/TOP based on having a radial connection (single point of connection) to the BES, provided that the loss of that radial connection is included in the set of study contingencies by the TP and TOP.
6. The team should consider addressing exceptions to the typical (radial connection – single point of connection) generator connections to the BES on a case-by-case basis involving the appropriate parties, such as the GO/GOP/TO/TOP/TP and Regional Entity, rather than creating requirements that apply to all GO/GOPs.

Is the drafting team headed in the right direction?

2. We applaud the team for seeking informal direction from the industry and believe the direction that the team is taking is appropriate.

### SERC OC standards Review Group Participation

Gerry Beckerle	Ameren
Jerry Hereen	MEAG
Jim Peterson	Santee Cooper
Shaun Anders	CWLP
Hamid Zakery	Dynegy
Scott McGough	OPC
David Plauck	Calpine
Pat McGovern	GTC
Melinda Montgomery	Entergy
Shardra Scott	Gulf Power
Doug White	NCEMC
Jake Miller	Dynegy
Larry Rodriguez	Entegra Power
Jim Case	Entergy
Ray Phillips	AMEA
John Troha	SERC

***“The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review group only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.”***

**Jack Cashin, Electric Power Supply Association**

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**COMMENTS:**

**EPSA Comments on Generation Requirements at the Transmission Interface – Project 2010-07**

The Electric Power Supply Association (EPSA)<sup>1</sup> endorsed the initial recommendations of the *Ad Hoc Group for Generator Requirements at the Transmission Interface*, and appreciates the opportunity to offer these informal comments on the March 2011 White Paper Proposal for Project 2010-07. Since NERC's creation of the "GOTO Team" in February of 2009, EPSA has supported the efforts of Ad-Hoc Group and now the Project 2010-07 Standards Drafting Team (SDT). While EPSA members' compliance registration includes several functional entity types, the bulk of competitive suppliers' registrations are as Generator Owners (GOs) and Generator Operators (GOPs).

EPSA's comments herein will focus on the following points for the Project 2010-07 SDT to consider concerning the White Paper Proposal:

- The definitions included in the currently underway Bulk Electric System (BES) definition Standard drafting effort and Generator Requirements at the Transmission Interface need to be aware of each SDT's work. Thus, the Project 2010-07 SDT should regularly consult with the Project 2010-17 SDT so that the two projects work as coordinated efforts.
- So that the Interface between generation and transmission can be clearly demarcated, correctly defining generator interconnection facilities is crucial to the successful completion of Project 2010-07.
- EPSA largely supports the White Paper's correct assessment about how Project 2010-07 will either require slight or no modification of other Standards to maintain reliability.
- Competitive Suppliers agree that FAC-001-1 and FAC-003-2 should apply to GOs, but suggest that the SDT revisit and revise the criteria that would trigger compliance for these two Standards.

**BES Definition and Exemptions – Working with Project 2010-17**

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<sup>1</sup> EPSA is the national trade association representing competitive power suppliers, including generators and marketers. These suppliers, who account for 40 percent of the installed generating capacity in the United States, provide reliable and competitively priced electricity from environmentally responsible facilities serving power markets. Each EPSA member typically operates in four or more NERC regions, and members represent over 700 registered entities in the NERC registry. EPSA seeks to bring the benefits of competition to all power customers. The comments contained in this filing represent the position of EPSA as an organization, but not necessarily the views of any particular member with respect to any issue.

Importantly, Project 2010-07 seeks to work in a coordinated way with the Definition of Bulk Electric System (BES) and Related Rules of Procedure Development Team – Project 2010-17 to appropriately designate facilities that would be included as part of the BES. The BES definition standard and associated exemption criteria need to be clear and widely understood so that BES generation and transmission facilities know their reliability responsibilities. The Project 2010-17 SDT needs to develop a crisp BES definition that can meld with the exemption criteria that will be developed. Importantly, the White Paper in stating Project 2010-07 Purpose, notes the Project's intent to have all generator BES facilities identified and integrated with other NERC Standards to ensure reliability. From the Paper:

The purpose of Project 2010-07—Generator Requirements at the Transmission Interface is to ensure that all generator-owned Facilities that are considered part of the Bulk Electric System are identified and that the level of reliability needed to operate such Facilities is appropriately covered under NERC's Reliability Standards.<sup>2</sup>

While the two efforts need to move forward in a coordinated way, neither project should impede the other's efforts or be stalled by the other's timetable.

EPSA supports the SDT's Purpose because it will eliminate the current conundrum when GO & GOPs are registered as TO & TOPs. This creates an untenable situation where GO & GOPs must comply with TO & TOP applicable standards despite not participating in the drafting of those Standards, because there was no evidence at the time that they would ever be registered as TO & TOPs. Project 2010-07 begins the process to change this situation and ensure against potential BES reliability gaps. By identifying the Standards that are appropriate for specific GO & GOPs the White Paper sets the course for the ERO to properly give GO & GOPs the due process accorded them under Section 215 of the Federal Power Act (FPA). Hence, generators can be engaged in the Project 2010-07 process so that those GO & GOPs that need additional responsibilities typically applicable to TO & TOPs will understand their full compliance obligations and ensure BES reliability. Moreover, coordination among Project 2010-07 and Project 2010-17 will ensure that the Standards will eliminate potential BES reliability gaps.

### **The Need for a Generator Interconnection Facilities Definition**

EPSA supports the SDT assertion that generating elements and facilities should be classified as part of the BES. Moreover, a clear BES definition will only be successful if the point of interconnection and associated functional registration is properly defined. The White Paper notes the need for good definitions for appropriate classification:

While not all power plants are considered part of the Bulk Electric System, ultimately, all the plants are interconnected to the bulk power system via their generator interconnection facilities. Of concern is how to classify all such

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<sup>2</sup> Project 2010-07: Generator Requirements at the Transmission Interface, White Paper Proposal for Informal Comment, March 2011, Page 2.

generating facilities, including their generator interconnection facilities, to determine what level of reliability is needed for such facilities.<sup>3</sup>

Generally, EPSA agrees with the SDT's conclusion that, "new definitions, modifying other definitions, and making changes to dozens of standards was no longer necessary." Much as the White Paper discusses (and is addressed later in these comments) many of the changes occurring through the BES revision will obviate the need for some of the definitional and standard modifications anticipated by the Ad-Hoc Group in 2009. EPSA agrees with this White Paper conclusion with the exception of generator interconnection facilities. A definition for generation interconnection facilities is necessary in Project 2010-07 Standard so that the interface between generators and transmission system can be clearly established and any ambiguities about reliability responsibilities for GOs & GOPs and TO & TOPs are eliminated.

The Ad-Hoc Group Report recommended the following definitions for incorporation into the existing standard:

#### **Generator Interconnection Facility**

*Sole-use facility for the purpose of connecting the generating unit(s) to the transmission grid. In this regard, the sole-use facility only transmits power associated with the interconnecting generator, whether delivered to the grid or delivered to the generator for station service or auxiliary load, or delivered to meet cogeneration load requirements.*

#### **Generator Interconnection Operational Interface**

*Location at which operating responsibility for the Generator Interconnection Facility changes between the Transmission Operator and the Generator Operator.<sup>4</sup>*

These definitions were developed with due consideration for varying configurations, outages, and generators materiality to the BES. The Facility definition defines the purpose of the facility, while the Generator Interconnection Operational Interface definition provides the functional lines of demarcation between the GO and the TO. The definitions were developed based on the purpose of generator interconnection facilities, their usage and how their usage differs from transmission facilities that comprise the interconnected grid. EPSA believes this is a sound basis for distinguishing BES facilities.

EPSA encourages the Project 2010-07 SDT to consider fitting the above definitions into the current White Paper for inclusion in the NERC Glossary. In addition, the other definitional changes proposed in the Ad-Hoc Group Report<sup>5</sup> should be retained and be considered for Glossary modification.

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<sup>3</sup> *Id* at Page 1.

<sup>4</sup> Generator Requirements at the Transmission Interface Final Report – Ad Hoc Group, November 16, 2009, Pages 17-18.

<sup>5</sup> *Id* at Pages 16-17.

Provided that there have been several FERC appeals<sup>6</sup> associated with this issue, EPSA encourages the SDT to include the above definitions so that registration can be based on a sound definition for generator interconnection facilities on which complying entities can rely. By providing the above definitions and changes to the NERC Glossary will add needed clarity. Including a generator interconnection facility definition in the Standard and in turn the NERC Glossary will appropriately set the stage for compliance registry criteria changes. EPSA believes the Project 2010-07 SDT should provide the definition changes for compliance registry amendment at the earliest date available so that any perceived registration reliability gaps can be corrected. Subsequently, as Regional Entities are considering new registrations they will have stronger criterion on which to base their decisions, which will make it so that NERC can “measure twice and cut once,” avoiding unnecessary resources expenditure on appeals.

### **Project 2010-07 and Other Relevant Reliability Standards**

EPSA generally supports proposed next steps and recommendations provided in the White Paper. This section of the paper updates (since the Ad-Hoc Group Report) the review of Standards and their requirements that should apply to appropriate generation facilities. Competitive suppliers agree with the SDT's conclusions that the Standards list beginning on page 5 of the White Paper<sup>7</sup> already apply to GO & GOPs due to changes since the Ad-Hoc Group Report and therefore do not need to be addressed further in Project 2010-07. The further White Paper discussion about how the circumstances for the EOP and PER and TOP (including considerations of PRC-001-2) Standards on pages 6 and 7 provides sound reasons that make EPSA believe that any reliability gaps perceived in 2009 that have since been closed.

### **Actions that Trigger Applicability of the FAC Standards**

The first recommendation in the White Paper is to include GOs in the applicability section of FAC-001-0, an assertion with which EPSA agrees. Appropriate generation facilities that would be identified as needing to comply with FAC-001-0 would need to comply with the Standard to ensure the reliability of the BES. However, EPSA is concerned with the White Paper's proposal that Requirement 4 be added to the applicability section of FAC-001-1. The proposed Requirement reads:

R4. Generator Owner that receives an interconnection request for its facility shall, within 45 days of such request, be required to comply with requirements R1, R2, R3 for the facility for which it received the interconnection request.

EPSA cautions the SDT about inadvertently commingling commercial issues with reliability issues. The interconnection requests involve other tariff issues for both GOs and TOs that need to be resolved before compliance can be established. Reliability will not be degraded if the triggering event for Standard compliance is set after the completion of other commercially

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<sup>6</sup> New Harquahala Generating Company, LLC, 123 FERC 61,173 (“New Harquahala”), order on clarification, 123 FERC 61,311 (2008); Cedar Creek Wind Energy, LLC, RC11- 1-000, appeal, 2010; Milford Wind Corridor Phase I, LLC, RC11-2-000.

<sup>7</sup> Project 2010-07: Generator Requirements at the Transmission Interface, White Paper Proposal for Informal Comment, March 2011, Page 5.



related regulatory obligations. Examples of commercial obligations that would need to be resolved include the need for an Open Access Transmission Tariff (OATT) to be filed with respect to the interconnection. During the proposed 45 day and potentially beyond, issues regarding transmission upgrades and financial responsibility for those upgrades would need to be resolved. Until upgrade issues are resolved, facility ownership and operation and maintenance responsibilities will not be specifically known. Additionally, if transmission owner and the interconnecting generator are affiliates, waivers with FERC acceptance will be required. The OATT and associated upgrade and affiliate waiver issues would need time to be sorted out prior to a registered GO being required to meet the requirements of FAC-001-0. Consequently triggering reliability compliance 45 days after the interconnection request is not feasible and does not enhance BES reliability. EPSA believes the SDT should ensure that reliability compliance should not be required before OATT changes and potential waivers are completed. Hence the criteria for triggering GO compliance with FAC-001-0 should only come into play after all commercial OATT issues are resolved.

The White Paper also proposes that the Generator Owner be added to all the requirements and measures that mention Transmission Owner for FAC-003-2. FAC-003-2 should apply to appropriate GOs, however EPSA asserts that the current proposal, which suggests applying the Standard to all generator interconnection facilities needs to have a more specific criteria to distinguish the specific GOs that need to comply with FAC-003-2. This would be consistent with the approach that was used by the Ad-Hoc Group in its Report where the “two-span test was supported for determining which GOs that FAC-003 should apply to:

In reaching this conclusion, the team considered other options that included inclusion of Generator Owners as applicable entities to FAC-003 based on a test for criticality, or to include Generator Owners as applicable entities in the existing version of FAC-003 without modification to the applicability criteria. The team, supported by a majority of industry commentators [sic] indicated the two-span test presented a simple and objective method to determine responsibilities for Generator Owners. Additionally, the “200 kV and above, or otherwise deemed critical to the Bulk Electric System” threshold is consistent with the current applicability of FAC-003 to Transmission Owners.<sup>8</sup>

EPSA supports the approach endorsed during the development of the Ad-Hoc Group Report and believes that FAC-003-2 need only apply to GOs with significant voltages and distances. Only Generator Owners of a Generator Interconnection Facility whose facilities operate at 200 kV and above or are otherwise deemed critical to the BES and whose Generation Interconnection Facility exceeds two spans (generally one-half mile from the generator property line) should need to comply with the vegetation management Standard. Therefore, the SDT should reexamine if FAC-003-2 should apply to all GOs only based on the generator interconnection facility. This must be done in conjunction with revising the definition of generator interconnection facilities.

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<sup>8</sup> Generator Requirements at the Transmission Interface Final Report – Ad Hoc Group, November 16, 2009, Pages 15.

## **Conclusion**

In summary, EPSA endorses SDT's work and appreciates the posting of the White Paper for an informal comment period. The White Paper provides an important bridge for Stakeholders to weigh current recommendations with the 2009 Ad-Hoc Group Report. Generally, EPSA agrees with the SDT's recommendations but still feels that to ensure that there are no BES reliability gaps requires coordination with the current BES SDT Project 2010-17; a definition for generator interconnection facilities needs to be included in the Standard; the Standards that no longer require changes since the 2009 Ad-Hoc Report have been correctly assessed; and, the compliance triggers and criteria for the FAC Standards need to be revised. Therefore, EPSA respectfully requests that the SDT for Project 2010-07 consider the recommendations herein.

**Natalie Mazey, Texas Reliability Entity, Inc.**  
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 512-583-4928

**COMMENTS:**

**Comments of the ERCOT Region NERC Standards Review Subcommittee (NSRS) on NERC Project 2010-07 White Paper Proposal on Generation Requirements at the Transmission Interface (GRTI)**

Submitted by: Group – ERCOT Region NERC Standards Review Subcommittee

Participating Members:

Name	Organization	Region
Bruce Wertz (Chair)	Independent Consultant	ERCOT
Pamela Zdenek (Vice Chair)	BP Products North America, Inc.	ERCOT
Brenda Hampton	Luminant	ERCOT
Tim Soles	Independent Consultant	ERCOT
Tom Foreman	LCRA	ERCOT

Contact: Natalie Mazey, Standards Development Coordinator, Texas Reliability Entity, Inc.

1. Coordination between Standard Drafting Teams. Based on the current status of the Bulk Electric System Standard Drafting Team (BESSDT) proposed BES definition, the White Paper Proposal (“Proposal”) does not provide a clear demarcation between generator interconnection facilities and the interconnected transmission facilities of the Transmission Owner/Operator.

The current BES definition makes no mention of what are or are not considered generation interconnection facilities, but merely includes “generating units greater than 20 MVA (aggregated 75 MVA at one site) from the generator terminals through the GSU which has a high side voltage of 100 KV or above.” Many registered generators own an additional interconnection line that is above 100 KV that, in turn, connects the generator to the transmission owner’s facilities and is also part of the generator interconnection. The currently proposed BES “core definition” would classify this line as a Transmission Element and could conceivably subject the GO to the full array of TO/TOP standards for this interconnection line.

According to its scope, the BESSDT is looking to the GRTISDT to define this demarcation through a definition, as proposed by the Ad Hoc group. As we interpret its scope, the BESSDT is defining what is or is not part of the BES without specifying what standards apply to different parts of the BES, or, for that matter, what standards apply to non-BES facilities.

**The NSRS asks for clarity of the definition, “generation interconnection facility” and for that definition to be included in the NERC Glossary. This subcommittee has no preference as to which committee takes ownership of this definition; however, we are substantially interested in expediting the completion of the review of this definition.**

2. Generation Interconnection Lines. The NSRS disagrees that generation interconnection lines are transmission lines from a functional standpoint. The function of the interconnection line is to interconnect the generator with the transmission system in a similar manner to the connectivity of a local distribution system to the transmission system (i.e., generally radial in nature). These lines only carry the output power or auxiliary power for that generation unit and are not for public use. The transmission system function is to deliver the generation to the load. That is not to say that some standards related to higher voltage lines may apply. Merely that, from a functional standpoint, the two are not the same and the reliability requirements are not the same.

**The NSRS agrees with the approach the SDT is taking involving the addition of a GO function to FAC-003. In the ERCOT Protocols, the definition of “Power Generation Company” (“PGC”) states that the PGC does not own a transmission or distribution Facility in this state other than an essential interconnecting Facility...” Therefore, by definition, a PGC cannot be TO/TOP.**

3. Proposed FAC-001 Revisions. The proposed FAC-001 revisions should not apply in the ERCOT region. In the ERCOT region, generation interconnection lines are private facilities that are not subject to third party interconnection requests. This revision only applies to a generation interconnection line that is considered part of the transmission network and for which the GO receives compensation for making this transmission line available.

**The FAC-001 revisions should include a regional difference exempting Generation Owners in the ERCOT region.**

4. Proposed FAC-003 Revisions. The NSRS agrees with the Ad Hoc Group’s Proposal 2, which provides for exclusions for short distance interconnections (i.e. - interconnection lines that do not exceed a distance that can be reasonably monitored), from the generator property line. In addition, there should be a process for demonstrating to the Regional Entity that the interconnection line has no vegetation around it to manage, i.e. in arid locations. Each entity should be allowed to develop this process based on their circumstances at their facility.

**Dan King, Sempra Generation**  
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## COMMENTS:

### **Comments of Sempra Generation on the Project 2010-07 Generator Requirements at the Transmission Interface White Paper**

Sempra Generation is the parent company of several generation-owning subsidiaries in the Western Electricity Coordinating Council region, including Mesquite Power, LLC (Mesquite), which is currently registered as both a Generator Owner/Generator Operator (GO/GOP) as well as a Transmission Owner/Transmission Operator (TO/TOP) due to the ownership of generator interconnection facilities.

Sempra Generation commends the work of the Project 2010-07 Standards Drafting Team (SDT) and believes the team is heading in the right direction, as evidenced by the March 2011 White Paper currently open for comment. Sempra Generation supports the position of the SDT that generator interconnection facilities should not trigger registration as a TO or TOP simply because the GO owns and/or operates transmission elements or facilities. Having said that, Sempra Generation agrees that, in order to maintain an adequate level of reliability in the Bulk Electric System, selected standards and requirements should apply to GO/GOPs in order to establish and maintain a clear delineation of responsibilities with respect to their generator interconnection facilities.

In the brief comments below, Sempra Generation provides feedback to the SDT on specific proposals in the White Paper.

- **Applicability of FAC-001-0 to the Generator Owner**

The SDT's proposed approach to FAC-001-0, which would require a GO to fully implement the R1 – R3 requirements within 45 days in the event the GO receives an interconnection request, may pose some difficult practical hurdles for GOs. A third-party request to interconnect to the GO's facilities would most likely occur in the circumstance where an existing radial transmission facility is sufficiently sized to accommodate additional generation, as is sometimes the case for renewable generation in particular, given that these facilities are also often sited many miles from the grid.

Third-party interconnection requests notwithstanding, if a GO is not also registered as a TO/TOP, it is because, as recognized at p. 3 of the White Paper, that GO's interconnection facilities are radial in nature, rather than "integrated." Adding an interconnecting third-party generator user to the GO's radial gen-tie facility does not automatically make that facility an "integrated" transmission element. If the GO's transmission facilities are not "integrated," it is generally going to be infeasible for the GO to fully implement the R1 - R3 requirements, since those requirements are clearly designed for owner/operators of integrated transmission facilities. In all actuality, the most appropriate entity to coordinate the process from the technical standpoint of facility connection requirements would be the BAA/TSP to whom the

GO is interconnected, since the BAA/TSP would invariably be an “Affected System” under the FERC’s pro forma Large Generator Interconnection Procedures.

Some of the practical difficulties facing GOs were recently highlighted by participants and panelists at the FERC Technical Conference on participant-funded transmission (Docket No. AD11-11-000, et al., March 15, 2011), where FERC is considering how to better implement the OATT requirement for participant-funded transmission facilities (including gen-tie facilities). In light of the discussion at the Technical Conference, it is reasonable to assume that FERC may be making adjustments to its policies in the future regarding how to address third-party access to GO interconnection facilities.

In addition, the seeming impracticality of a generator complying with FAC-001-0 R1-R3 was acknowledged and documented in 2008 by NERC and WECC in the Harquahala “Compliance Protocol” document, which was recently filed at FERC in the Cedar Creek Wind/Milford Wind Corridor proceeding (FERC Docket No. RC11-1-000 et al., filed December 28, 2010). With respect to compliance with FAC-001-0 R1-R3, the Compliance Protocol provides as follows:

Because Harquahala does not know what equipment would be required for a specific interconnection to the Harquahala transmission facilities, to satisfy these Requirements, Harquahala will generally describe the factors it will consider if interconnection is requested, including any necessary coordination with SRP, and the necessity of installing certain equipment for measuring interconnection capability. Harquahala will not be required to publicly publish its facility connection requirements, but Harquahala will provide them upon request, as required in R3. If Harquahala were to receive a request for interconnection, Harquahala will work with the requesting entity to develop full interconnection requirements in a timely manner.

Instead of requiring the GO to comply with the full panoply of FAC-001-0 R1– R3 requirements (all within 45 days of the third-party interconnection request), Sempra Generation encourages the SDT to consider R4 language that recognizes the practical hurdles associated with implementing the requirements for radial facilities, and that takes an approach more akin to the Harquahala Compliance Protocol with respect to this Standard. Specifically, the SDT should consider R4 language that would require the GO receiving the interconnection request (i) to implement the requirements of R1 – R3 only to the extent those requirements are applicable to radial facilities; and (ii) to coordinate with its BAA/TSP on such implementation. In terms of timing, the SDT should consider whether the proposed 45 days is realistic, and whether a 90-day deadline would be more appropriate. The flexibility inherent in the above approach would likely avoid potential conflicts with any revised FERC policies resulting from the aforementioned Technical Conference.

- **Applicability of FAC-003-2 to the Generator Owner**

Sempra Generation supports the addition of “Generator Owner” to the Applicability section of FAC-003-2.

- **Project 2010-17—Definition of Bulk Electric System**

Sempra Generation supports the need for the coordination between the Project Teams for Project 2010-07 and Project 2010-17 (Definition of Bulk Electric System), and agrees that changes made to the BES definition will be instrumental in covering the reliability gap with respect to generator requirements at the transmission interface. However, because the Project 2010-17 BES work may take a significantly slower track than the SDT's progress, Sempra Generation encourages the SDT to weigh the risks and benefits of including of a definition of "Generator Interconnection Facility" in the NERC Glossary and associated clarifications to the standards, as proposed in the *Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface*.

- **Other Solutions**

As referenced in the White Paper, the standards outlined will likely not take effect for a year or more. In the meantime, GOs such as Mesquite will continue to be under increased risk of non-compliance due to their registration as TO/TOPs, and will need to incur substantial compliance costs for TO/TOP requirements that are clearly not an appropriate fit. Accordingly, Sempra Generation encourages consistent application of responsibilities under the Standards in all NERC regions, and urges NERC to adopt the necessary changes to the NERC Glossary, Registration Criteria, and/or Standards to ensure consistency exists throughout the regions.

- **Conclusion**

The Final Report and White Paper are obviously products of detailed analysis and thoughtful consideration of the myriad issues surrounding the reliability implications of ownership and operation of generator interconnection facilities. It is noteworthy – though hardly surprising – that, after many months of study, the GO/TO Task Force and the SDT, balanced groups comprised of members from a broad spectrum of functional categories, have concluded that only modest changes to the Reliability Standards would be required in order to ensure that no gaps exist and that generator interconnection facilities are operated reliably. When implemented, the recommendations included in the White Paper should go a long way toward providing the regulatory and compliance certainty needed by generators who own or operate generator Interconnection facilities. Accordingly, Sempra Generation encourages the continued work of the Project 2010-07 team.

Sempra Generation is not the same company as the utility, SDG&E or SoCalGas, and the California Public Utilities Commission does not regulate the terms of Sempra Generation's products and services.

**Amir Hammad, Constellation Power Generation**

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**COMMENTS:**

Dear Drafting Team Members:

Thank you for the opportunity to offer input at this stage of the standard development. Below, please find comments from Constellation Power Generation and Constellation Commodities Group (collectively CPG):

1. How can the proposal outlines in the White Paper be improved? Is the drafting team heading in the right direction?

CPG agrees with many of the aspects discussed in the White Paper such as on page 3 “...qualifying generator interconnection facilities should be classified as transmission. That does not, however, mean that a Generator Owner or Generator Operator should be required to automatically register as a Transmission Owner or Transmission Operator simply because it owns and/or operators transmission Elements or Facilities” and that “requiring any classification that subjects Generator Owners and Generator Operators to all the standards applicable to Transmission Owners and Transmission Operators would do little, if anything, to improve the reliability of the Bulk Electric System.” CPG also agrees with the limited number of proposed reliability standard changes that this drafting team has identified in the White Paper.

However, the White Paper also states that any potential reliability gaps can be closed by “properly applying standards or specific standard requirements to Generator Owners and Generator Operators.” CPG does not agree with that statement. Applying selected requirements or standards to all GOs and GOPs when any potential reliability gaps only apply to a minority of GOs and GOPs is not the correct approach.

The proposed White Paper departs from some of the valuable concepts within the Ad Hoc Group report from November 2009, which CPG would like to see reconsidered. The drafting team should revisit the Ad Hoc report recommendation to define “Generator Interconnection Facility”. Because generator interconnection facilities are distinctly different from the traditional transmission function understood within the Bulk Electric System, generator interconnection facilities should be independently defined. Once clearly defined, the drafting team should consider the subset of transmission geared standards useful to address reliability issues at the subset of applicable GOs and GOPs.

The draft definition language in the Ad Hoc Report offers a good starting point:

***Generator Interconnection Facility***



*Sole-use facility for the purpose of connecting the generating unit(s) to the transmission grid. In this regard, the sole-use facility only transmits power associated with the interconnecting generator, whether delivered to the grid or delivered to the generator for station service or auxiliary load, or delivered to meet cogeneration load requirements.*

***Generator Interconnection Operational Interface***

*Location at which operating responsibility for the Generator Interconnection Facility changes between the Transmission Operator and the Generator Operator.*

2. The drafting team has chosen to use informal means of receiving industry feedback (webinars, presentations before industry stakeholder groups, etc) prior to expending valuable industry resources to develop specific proposals for reliability standard requirements, measures, VSLs, etc. Do you have any further suggestions for seeking industry input before the project moves into a more formal development phase?

Constellation supports use of informal feedback opportunities as part of the development process. This allows for constructive input early in the process without the response obligations of the formal steps which will take place later in the process. In addition, informal settings offer industry members the chance to better understand the issues and decision making behind the standard development and encourage greater familiarity with the proposal before it reaches formal ballot.

3. The Ad Hoc group originally proposed the new terms “Generator Interconnection Facility” and “Generator Interconnection Operational Interface” as part of this project. The Project 2010-07 drafting team believes that changes to the definition of Bulk Electric System under Project 2010-07 and modifications to a select group of standards can accomplish the same goal without the need for new definitions. Do you support this approach? If not, please explain.

CPG disagrees with this approach. The BES team is currently standardizing the definition of BES using input from the regions and NERC. Its scope does not include creating new functional models and changing standards to close any perceived gaps in reliability. The Ad Hoc team’s proposal of creating new terms such as “Generator Interconnection Facility” is a much better approach. By clearly defining that term, the small subset of GOs and GOPs that may have these facilities can be made subject to the select TO requirements or standards to address the potential reliability question.

Thank you for your consideration. Please contact me with any questions.

**Kurtis B. Chong, Independent Electricity System Operator**

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905-855-6282

**COMMENTS:**

**IESO Comments on Project 2010-07**

**“Generator Requirements at the Transmission Interface”**

We thank the Project 2010-07 SDT for the opportunity to comment on the posted white paper and attachments. IESO supports the effort to properly determine which TO/TOP reliability standards requirements ought to apply to GO/GOPs to promote BES reliability, while at the same time not burdening GOs/GOPs with the obligation of complying with other requirements that are not relevant to their operation. We offer these comments:

The introduction to the white paper raised the question of classifying generating facilities, including their generator interconnection facilities, to determine what level of reliability is needed for such facilities. Further, on page 2, the SDT referred to “qualifying” generator interconnection facilities. However, it is not clear what are the qualifying criteria. Are the qualifying criteria for Elements and Facilities the BES definition criteria? If so, this should be stated explicitly.

We agree with the proposed changes to FAC-001-0. An alternative approach would have been to include the GO in each of requirements R1 to R3. That would however have meant that the GO would have to document, maintain and publish facility connection requirements even in cases where requests for same are unlikely. The proposed approach makes compliance with R1 to R3 mandatory only upon receipt of a request and avoids potentially unnecessary upfront work by the GO.

In FAC-001-0, we suggest that R4 be modified as follows: Start the sentence with “The” and delete “be required to”.

We agree with the proposed changes to FAC-003. The last sentence of footnote 2 of FAC-003 should also be modified to include the Generator Owner.

The proposed definition of Generator Interconnection Operational Interface was “Location at which operating responsibility for the Generator Interconnection Facility changes between the Transmission Operator and the Generator Operator.” We do not understand the SDT’s rationale for removing this definition since it does not refer to Elements and Facilities rated at 100 kV and above. It is also unclear how the original objective meant to be achieved by the proposed change to EOP-008-0 R1.3 would be met. Please clarify.

**Sandra Shaffer, PacifiCorp**  
[Sandra.Shaffer@PacifiCorp.com](mailto:Sandra.Shaffer@PacifiCorp.com)

## COMMENTS:

**PacifiCorp respectfully submits the following comments with respect to Project 2010-07: Generator**

**Requirements at the Transmission Interface: White Paper for Informal Comment:**

PacifiCorp generally agrees with the objective and purpose of Project 2010-07, namely, to ensure that all generator-owned facilities that are considered part of the bulk electric system (“BES”) are identified and that the level of reliability needed to operate such facilities is appropriately covered under NERC’s Reliability Standards.

However, PacifiCorp believes that certain of the standard drafting team’s proposals are not consistent with this objective.

Specifically, in “Proposed Next Steps and Review of Reliability Standards,” item #3, the standards drafting team proposes to ensure that the responsibility for generator interconnecting line leads is appropriately and clearly assigned to Generator Owners and Generator Operators. PacifiCorp believes that this step is not necessary at this time and is inconsistent with the purpose of Project 2010-07. The purpose of the project is to ensure that the facilities considered part of the BES are properly identified. The definition of “BES” should define the facilities that are part of the BES; it should not define responsibility or ownership of those facilities. Although typically generator lead lines are owned and operated by the Generator Owner or Generator Operator, they may also be owned or operated by the Transmission Owner or Transmission Operator. The BES definition should remain broad enough to take this difference into account.

PacifiCorp disagrees that a requirement should be added to FAC-001-0 to require a Generator Owner that receives an interconnection request for its facility to comply with requirements R1, R2, and R3. First, it is not clear to PacifiCorp that the lack of this requirement could result in gaps. The standards drafting team provides no support for the existence of such a gap and rather simply makes an assumption that it could result in reliability gaps. PacifiCorp is not aware of many generating facilities that, given FERC’s open access requirements, receive interconnection requests. That said, PacifiCorp would admit that it is theoretically possible that a Generator Owner would receive an interconnection request. If such a thing were to occur, PacifiCorp believes that is unreasonable to require the Generator Owner to have facility connection requirements in place within 45 days of such request. The Generator Owner should only be obligated to develop such facility connection requirements if the interconnection request will be granted and new third-party facilities will actually be interconnected to the Generator Owner’s facilities. In this manner, the burden of developing such facility connection requirements will only apply when necessary to enhance reliability.

**Annette M. Bannon, PPL Generation, LLC**  
ambannon@pplweb.com  
610-774-2064

**COMMENTS:**

The following NERC registered entities have reviewed and endorse the EPSA comments on this project.

NCR00882 Lower Mount Bethel Energy, LLC  
NCR00883 PPL Brunner Island, LLC  
NCR00886 PPL Holtwood, LLC  
NCR00887 PPL Martins Creek, LLC  
NCR00888 PPL Montour, LLC  
NCR05329 PPL Montana, LLC

Thank you for considering the industry's comments on the Generator Requirements at the Transmission Interface White Paper.

**Natalie McIntire, American Wind Energy Association**  
natalie.mcintire@gmail.com  
651-964-2599

## **COMMENTS:**

### **American Wind Energy Association Informal Comments on NERC Project 2010-07 Generator Requirements at the Transmission Interface**

The American Wind Energy Association (AWEA) appreciates the opportunity to submit comments on the NERC Project 2010-07 white paper (White Paper), "Generator Requirements at the Transmission Interface." AWEA supports the proposed plan from the Generator Requirements at the Transmission Interface Ad Hoc Group (GOTO Ad Hoc Group), which concludes that:

1. If Generator Interconnection Facilities operate at 100 kV or greater or are deemed critical to the Bulk Electric System, it would make the Generator Interconnection Facility part of the Bulk Electric System with respect to Generator Owner and Generator Operator requirements but not for Transmission Owner or Transmission Operator requirements.
2. A Generator Owner or Generator Operator that owns and/or operates a Generator Interconnection Facility (that is, a sole-use facility that interconnects the generator to the grid) need not be registered as a Transmission Owner or Transmission Operator by virtue of owning or operating its Generator Interconnection Facility.
3. A Generator Interconnection Facility is considered as if it is part of the generating facility specifically for purposes of applying Reliability Standards to a Generator Owner or Generator Operator.<sup>1</sup>

The NERC Standard Development Team's (SDT) White Paper appears to be generally consistent with the recommendations of the GOTO Ad Hoc Group. While the SDT explains that generator interconnection facilities should be classified as part of the Bulk Electric System (BES), it also states that "(this) does not mean, however, that a Generator Owner or Generator Operator should be required to automatically register as a Transmission Owner or Transmission Operator simply because it owns and/or operates transmission Elements or Facilities. ... [T]hese are most often not part of the integrated bulk power system, and as such should not be subject to the same level of standards applicable to Transmission Owners and Transmission Operators who own and operate transmission Facilities and Elements that are part of the integrated bulk power system."

AWEA supports the SDT's conclusion that "[w]hen the transmission Elements and Facilities owned and operated by Generator Owners and Generator Operators are nonnetwork/non-integrated transmission, applying *all* standards applicable to Transmission Owners and Transmission Operators would have little effect on the overall reliability of the Bulk Electric System."

AWEA also supports the SDT effort to rework the proposal from the GOTO Ad Hoc Group, not because of significant differences between ultimate goals, but to simplify this

modification process by limiting the number of standards that need to be changed.

<sup>1</sup> NERC, "Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface", November 16, 2009, Page 3.

We note, however, that the SDT does not clarify how, or under what circumstances, a Generator Owner or Operator will be exempted from registration as a Transmission Owner or Operator and the corresponding requirements. The new proposed definitions for the BES from Project 2010-17, Definition of Bulk Electric System, include the interconnection facilities along with the facilities of individual generators or generation plants. If these proposed changes are adopted, we think there needs to be clarification as to whether that would exempt GO/GOPs from the requirements that TO/TOPs. Therefore, AWEA requests greater clarification of how, by definition or through registration criteria, the SDT intends to implement the recommendation that a GO/GOP should not be registered as a TO/TOP solely due to its interconnection facilities. AWEA reads the White Paper to state there are few requirements that currently apply to TO/TOPs that the SDT believes are critical enough that they should also apply to GO/GOPs who have related interconnection facilities that qualify as part of the BES. These include requirements related to registration of facilities that receive interconnection requests, as well as vegetation management requirements that typically apply to transmission facilities. AWEA details our concerns about both of these requirements below.

#### FAC-001-0 – Facility Connection Requirements

Given the inconsistent understanding of which interconnection facilities are required to offer interconnection or transmission service, AWEA urges the SDT to watch how this issue unfolds at FERC,<sup>2</sup> and to ensure that the additional requirements proposed in FAC-001 apply only to generators who are required to accept interconnection requests. Our concern is that a generator owner of interconnection facilities would be required to incur costs and devote staff time to developing the facility connection requirements as stated in FAC-001, even though a submitted request might not result in another party interconnecting.

#### FAC-003-02- Transmission Vegetation Management

Given that this standard applies to lines 200kV and higher, it will apply only to the largest interconnection facilities. Still, AWEA believes the vegetation requirements the SDT has proposed in FAC-003 may be excessive for interconnection facilities that are of limited length. Wind generators by their very nature are intermittent and, therefore, are not relied upon in the same way as other generators with regard to the reliability of the grid. Vegetation issues that cause problems with wind generator interconnection facilities will not threaten reliability, but will only limit the ability for the generator to deliver its output to market, which is no different than the situation when the wind is not <sup>2</sup> A recent FERC Technical Conference on Priority Rights to New Participant-Funded Transmission Projects, on March 15, addressed the question of when and how a generator owner of an interconnection facility must receive an interconnection. It is possible that additional rules may come out of this process to clarify these issues.

blowing. AWEA urges the SDT to consider limiting application of this requirement to longer interconnection facilities, such as those that of . mile or more.

**John Criner, Kelson Energy, Inc.**  
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## **COMMENTS:**

### **Comments of Kelson Energy, Inc. (“Kelson”) on White Paper Proposal for Informal Comment in Project 2010–07: Generator Requirements of the Transmission Interface (“White Paper”)**

Kelson supports the proposition set forth in the White Paper that a Generator Owner (GO) or Generator Operator (GOP, collectively GO/GOP) should not be required to automatically register as a Transmission Owner (TO) or Transmission Operator (TOP) “simply because it owns and/or operates transmission Elements or Facilities.”<sup>1</sup> However, the White Paper does not address this important registration issue. Kelson understands that this is the result of the procedural limitations of the Project 2010–07 Standards Drafting Team (SDT), meaning that the SDT cannot propose changes to the *NERC Statement of Compliance Registry Criteria (Registry Criteria)*, but may only propose changes to Reliability Standards. However, the result is that this registration issue is still not being resolved by NERC in any public process. The SDT makes proposals to add GO requirements, yet it remains uncertain how GO/GOPs will be treated with respect to the TO/TOP requirements. Kelson believes this should be addressed as a whole. For this reason, Kelson provides comments on how the registration issue should be addressed, in addition to providing specific comments on the SDT’s proposals.

#### **I. Registration**

Kelson recommends that the SDT propose a new definition to the NERC Glossary for “Generator Interconnection Facility” (GIF), as was proposed in the *Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface* (GO/TO Final Report) as follows:

Sole-use facility for the purpose of connecting the generating unit(s) to the transmission grid. In this regard, the sole-use facility only transmits power associated with the interconnecting generator, whether delivered to the grid or delivered to the generator for station service or auxiliary load, or delivered to meet cogeneration load requirements.<sup>2</sup>

In addition, Section III of the *Registry Criteria* should be revised to exclude an entity that owns and/or operates GIF as their only transmission facilities from registration as a TO and/or TOP as follows:

<sup>1</sup>White Paper at 3.

<sup>2</sup>GO/TO Final Report at 17.2

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Section III of the *Registry Criteria* states that the entities that meet the definition of the different registration categories, including TO and TOP, should be excluded from registration if they do not meet any criteria listed in Section III. The criteria listed for TO and TOP in Section III is currently set forth as follows:

III.d.1 An entity that owns/operates an integrated transmission element associated with the bulk power system 100 kV and above, or lower voltage as defined by the Regional Entity necessary to provide for the reliable operation of the interconnected transmission grid; or

III.d.2 An entity that owns/operates a transmission element below 100 kV associated with a facility that is included on a critical facilities list that is defined by the Regional Entity.

Kelson recommends that this be changed as follows:

III.d.1 An entity that owns/operates an integrated transmission element associated with the bulk power system 100 kV and above, or lower voltage as defined by the Regional Entity necessary to provide for the reliable operation of the interconnected transmission grid, and not including a Generator Interconnection Facility; or

III.d.2 An entity that owns/operates a transmission element below 100 kV associated with a facility that is included on a critical facilities list that is defined by the Regional Entity.

These changes would prevent entities being registered as TO and/or TOP solely due to their Generator Interconnection Facilities. At the same time, the *Registry Criteria* always gives a Regional Entity the ability to register entities that do not otherwise fit within the *Registry Criteria* if it reasonably demonstrates that the entity is a bulk power system owner, or operates, or uses bulk power system assets and is material to the reliability of the bulk power system.<sup>3</sup> Thus, if there is a unique situation that indicates a GIF must comply with all of the TO and/or TOP requirements, a mechanism is available for registration.

<sup>3</sup>*Registry Criteria*, Note 1.

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## II. FAC-001

Kelson does not object to the addition of GO to the applicability section of FAC-001, but objects to the content of R4. FERC requires that when a generator receives an interconnection request from a nonaffiliate,<sup>4</sup> it must file an Open Access Transmission Tariff within 60 days of receiving that request. Kelson recommends that R4 be revised to be more consistent with FERC's policies, at least for those entities regulated by FERC. Generator Owner that receives an interconnection request for its facility from a nonaffiliated entity, as determined by FERC, shall, within 45 days of such a request after its Open Access Transmission Tariff is accepted by FERC, be required to comply with



requirements R1, R2 and R3 for the facility for which it received the interconnection request. If the Generator Owner is not subject to FERC Open Access Transmission Tariff requirements, then it shall be required to comply with the requirements R1, R2 and R3 within 45 days of such a request.

### **III. FAC-003**

While Kelson agrees that vegetation management might need to apply to certain generator interconnection facilities, particularly those of significant length, indiscriminate application of FAC-003 to all GOs is not the appropriate solution. There are significant differences between the facilities that make up part of the integrated transmission grid and interconnection facilities—many, and sometimes all, interconnection facilities are “inside the fence,” where all vegetation will have been cleared as a matter of course. In this case, vegetation would not be an issue and application of a standard like FAC-003 would be an inappropriate and unnecessary burden on the owner of the interconnection facilities. While R4.2.4 might exclude entities with facilities inside the fence, even for facilities that extend beyond the fence, any vegetation management standard must be flexible to accommodate variations since interconnection facilities may consist of generator leads of varying lengths from a few feet to many miles. A one-size-fits-all approach like FAC-003 is not appropriate. The vegetation management standard imposed on GOs should be less prescriptive than the one applicable to TOs. Kelson proposes that a GO vegetation management standard broadly require the GO to ensure that vegetation be maintained, and allowing the GO to develop and implement an appropriate program for vegetation, depending on the extent of vegetation within its right-of-way.

*4Sky River, LLC*, 134 FERC ¶ 61,064, at P 13 (2011).

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### **IV. Definition of Bulk Electric System (BES)**

Kelson has no objection to relying on a new BES definition to ensure that the responsibility for generator interconnection leads appropriately and is clearly assigned to GO/GOPs with respect to the standards listed in the White Paper, so long as the final, approved BES definition actually achieves this end. Otherwise, there will be a need to clarify that the GO/GOP would need to include their generator interconnection facility in their compliance activities for these activities. At the same time, waiting for the final, approved BES definition to address this issue could prolong this process unnecessarily, and therefore, Kelson suggests that the SDT propose to make the needed clarifications. This could be done by changing the definition of GO to be defined as an “[e]ntity that owns and maintains generating units, *including its Generator Interconnection Facility*”, as recommended in the GO/TO Final Report.<sup>5</sup> Alternatively, NERC could issue a Compliance Application Notice clarifying that when a GO and/or GOP is implementing the standards listed on pages 5-6 of the White Paper, its compliance activities should encompass the generator interconnection facilities.

**Dale Fredrickson, Wisconsin Electric**  
[Dale.Fredrickson@we-energies.com](mailto:Dale.Fredrickson@we-energies.com)

## **COMMENTS:**

The efforts of the SDT are appreciated in support of reliable operation at the Generator-Transmission interface. In particular, we believe that the SDT decision not to propose new definitions or to change other existing definitions, and not to make changes to dozens of standards is a good one. In this respect we fully agree with the direction of the SDT.

However, we take issue with other aspects of the white paper. First, we believe that the statement (p. 4, Para. 3) that “requiring any classification that subjects Generator Owners and Generator Operators to all the standards applicable to Transmission Owners and Transmission Operators would do little, if anything, to improve the reliability of the BES”, is not precisely true. Much greater, such a requirement would actually reduce reliability. The costs and efforts to comply with these standards would displace time and money that could have been invested in real reliability enhancements. This entire paragraph needs more clarity. The second sentence appears to say much the same as the first, but it qualifies the Generator Owner/Operators “transmission Elements and Facilities” as those which are nonnetwork/non-integrated. It is unclear just what statement is being made here, especially about whether any Generator Owner/Operators “transmission Elements and Facilities” would indeed be considered network/integrated. Our understanding is that by definition, these Elements and Facilities (generator tie lines) are not network lines in the sense that Transmission Lines are network lines.

As for the Proposal #1 to add the GO to the Applicability section of FAC-001-0, Facility Connection Requirements, we do not support this. The need for this is not apparent. We suggest that there are few, if any, situations where there would be an interconnection request directed to a Generator Owner. It is a unique characteristic of transmission systems that they are the gatekeepers which establish connections for generation and load. We suggest this is an unnecessary extension of a standard to Generator Owners, and is not required for reliability.

Proposal #2 adds the Generator Owner to the Applicability section of FAC-003-2, Transmission Vegetation Management. This is done across the board, with no criteria for circuit length or where the circuit is located. We maintain this is much too broad, and will result in inefficient allocation of resources. The FAC-003-2 standard appears to have very demanding requirements for transmission right-of-way vegetation management and substantial documentation requirements. The reliability risk of vegetation problems on tie lines at the Generator-Transmission interface is almost zero. In cases where the affected “transmission Elements and Facilities” is very short (in one case of ours, from the plant to the switchyard on the opposite side of a street), or in cases where such facilities are on the property of the Generator Owner, the requirement to comply with FAC-003 is not justified by reliability risks, and we strongly object to this proposal. For these cases, the resources required to comply with FAC-003 standard would be considerable. We propose that the SDT implement the Material Impact Test suggested in the Ad Hoc Group’s Final Report

(November 2009) Recommendation #3 (p. 10): “Modify the applicability of FAC-003-1 to apply to Generator Owners when their Generator Interconnection Facility operates at 200 kV or above and exceeds two spans (generally more than one-half mile, see p. 3, #6) from the generator property line...”

We appreciate the work of the SDT, and the opportunity to offer our comments.

**Ed Davis, Entergy Services**  
EDAVIS@entergy.com  
504-576-3029

## COMMENTS:

### ENTERGY COMMENTS

#### NERC PROJECT 2010-07

#### GENERATOR REQUIREMENTS TO THE TRANSMISSION INTERFACE

Informal Comment Period – Ending April 4, 2011

Ed Davis

504-576-3029

We suggest the following changes and additions to the proposed draft changes to FAC-001.

First, the proposed R4 states “ .. interconnection request for its facility..”. It would be clearer to us if the request was stated as “to” its facility and suggest changing “for” to “to”:

**R4.** Generator Owner that receives an interconnection request ~~for~~to its facility shall,

Second, the proposed change to FAC-001, addition of Requirement 4, will require the generator owner to comply with FAC-001 Requirements 1-3 under certain conditions. Therefore, we suggest the following changes to R1-3 to conform to the addition of R4:

**R1.** The Transmission Owner and/or Generator 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 and/or Generator Owner planning criteria and facility connection requirements. The Transmission Owner’s and/or Generator Owner’s facility connection requirements shall address connection requirements for:

**R2.** The Transmission Owner’s and/or Generator Owner’s facility connection requirements shall address, but are not limited to, the following items:

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

**David K Thorne, Pepco Holdings, Inc. - PHI**  
dkthorne@pepco.com  
302-283-5718

**COMMENTS:**

Pepco Holding Inc. Comments

PHI supports the general concepts and direction of the proposals as defined in the published white paper.

**Gretchen Schott, BP Wind Energy North America Inc.**  
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## **COMMENTS:**

### **BP Wind Energy North America Inc. Comments on Project 2010-07: Generator Requirements at the Transmission Interface**

On Friday, March 4, 2011, the Project 2010-07 Generator Requirements at the Transmission Interface drafting team posted for a 30-day informal comment period a white paper on proposed concepts to support the modifications of various standards to clarify the reliability standard responsibilities of Generator Owners and Generator Operators at the interface to the interconnected grid.

BP Wind Energy North America Inc. (“BP Wind Energy”) submits the comments set forth below on the white paper. Various BP Wind Energy subsidiaries own and operate wind-powered generating facilities throughout the United States and are registered with NERC as Generator Owners (“GOs”) and Generator Operators (“GOPs”) in RFC, SPP, TRE, and WECC.

BP Wind Energy agrees with, and supports, the approach recommended in the white paper regarding how to address the applicability of NERC reliability standard to GOs and GOPs that own and/or operate generator interconnection facilities. While BP Wind Energy does not agree with the conclusion set forth in the white paper that generator interconnection facilities should be classified as transmission, BP Wind Energy strongly agrees with the white paper’s recommendation that a GO or a GOP that owns and/or operates generator interconnection facilities should not automatically be registered as a Transmission Owner (“TO”) or Transmission Operator (“TOP”) simply because it owns and/or operates such facilities. Generator interconnection facilities are typically not part of the integrated transmission system and, therefore, their reliable operation and maintenance should not require adherence to the same level or scope of standards that are applicable to transmission facilities that are part of the integrated transmission system. Indeed, requiring GOs and GOPs that own and/or operate generator interconnection facilities to adhere to *all* NERC reliability standards that are applicable to TOs and TOPs that own and/or operate transmission facilities that are part of the integrated grid makes little sense as such an approach is likely to do little to increase or ensure reliability of the bulk power system, fails to focus on what is needed to ensure reliable operation and maintenance of generator interconnection facilities, and results in unnecessary increased costs and burdens on GOs and GOPs.

By contrast, BP Wind Energy believes that the targeted approach recommended in the white paper – i.e., to clarify the applicability of a select number of reliability standards to GOs and GOPs by modifying the Purpose, Functional Entity section, requirements, and measures – is a better way to address reliable operation and maintenance of generator interconnection facilities and one that should go a long way toward providing clarity to the industry (and, in particular, GOs and GOPs) regarding GO and GOP reliability obligations.

However, given the targeted nature of the approach, BP Wind Energy strongly urges the drafting team to consider drafting and recommending, or recommending that NERC draft, revisions to the Statement of Compliance Registry Criteria that clarify the criteria for registration applicable to generator entities that own and/or operate generator interconnection facilities to ensure that, going forward, GOs and GOPs that own and/or operate such facilities are not improperly registered as TOs and TOPs. GOs and GOPs need to have the solution documented and applied in a consistent manner across regions.

Moreover, BP Wind Energy disagrees with the changes that the SDT is proposing be made to FAC-001-0. As BP Wind Energy reads the proposed changes, any GO that receives a request for service over a generator interconnection facility in which the GO has an ownership interest would be required to comply, within 45 days of receiving such a request, with the requirements set forth in R.1., R.2., and R.3. of FAC-001-0. Those requirements would obligate a GO to publish facility connection requirements for its generator interconnection facility and to ensure that the requirements address, among other things, procedures for coordination of joint studies of new facilities and their impacts on the interconnected transmission systems.

The Federal Energy Regulatory Commission ("Commission") is in the midst of considering issues related to priority access rights relating to participant-funded transmission projects, including those related to generator interconnection facilities (in particular, generator lead lines), as evidenced by the technical conference held by Commission staff on March 15, 2011 and the Commission's request in Docket No. AD11-11-000 for the submittal of comments by April 21, 2011 on such issues. As a result, the requirements applicable under Commission policy to a generator that receives a request for service over a generator interconnection line are likely to be revised or, at the very least, clarified by the Commission within the next year.

While it is difficult to predict what changes or clarifications the Commission might make, it is very possible that such changes or clarifications will conflict with the requirements set forth in FAC-001-0. For example, the Commission might establish a safe harbor period during which a generator would be permitted to have priority access over the use of the generator interconnection line and would be able to decline to provide service over the generation interconnection line. If the Commission were to adopt this proposal and a generator were to receive a request for service during the safe harbor period, the generator would be permitted to decline service under Commission policy but, under FAC-001-0, would be required to publish facility connection requirements for service that it will not be providing. The Commission could also establish a pro forma tariff governing service over generator interconnection lines with terms and conditions of service that differ significantly from the Commission's current pro forma open access transmission tariff. If the Commission were to adopt this proposal and a generator were to receive a request for service, the requirements of FAC-001-0 could end up requiring a generator to adopt facility connection requirements that are not required under the pro forma generator interconnection tariff and viewed to be more stringent, such as procedures for coordination of joint studies.

In BP Wind Energy's view, neither of these results makes sense from a compliance or reliability perspective. BP Wind Energy therefore urges the SDT to either to not propose to add references to GOs in FAC-001-0 or, alternatively, to ensure that any requirements imposed on a GO under FAC-001-0 are consistent with, and not more stringent or in conflict with, Commission policy. At a bare minimum, the proposed timeframe for imposing the requirements in FAC-001-0 on GOs that receive an interconnection request should be changed to 60 or more days to be consistent with current

Commission policy that requires a generator to file with the Commission an open access transmission tariff within 60 days of receiving a request for service.



**Rebecca Baldwin, Transmission Access Policy Study Group**  
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202-879-4088

## COMMENTS:

### **Comments of the Transmission Access Policy Study Group on the White Paper Proposal in Project 2010-07: Generator Requirements at the Transmission Interface**

TAPS appreciates the opportunity to comment on the GO/TO drafting team's White Paper. We generally support the approach proposed in the White Paper but have some specific suggestions.

We suggest that at minimum, this drafting team's goal should be to give guidance as to what Facilities are covered under a GO/GOP registration and therefore do not require TO/TOP registration. For example, radial generator leads, including all Elements radial to the generator, should be included in the entity's GO/GOP responsibility and should not require TO/TOP registration.

#### **A. Framework**

As the White Paper acknowledges in footnotes 1 and 2, it refers to both the "Bulk Electric System" and the "bulk power system." Although, as noted in footnote 2 to the White Paper, "bulk power system" is defined in Section 215 of the Federal Power Act, it is not a NERC Glossary defined term; furthermore, "bulk power system" and "Bulk Electric System" may or may not be synonymous terms. *See* Order 743-A, Paragraphs 61-63. While we recognize that there are existing NERC documents that refer to the bulk power system, we suggest for the sake of clarity and precision that going forward, so long as the contours of the "bulk power system" are not clearly defined, NERC documents should use only the NERC-defined term "Bulk Electric System."

One area in which the bulk *power* system is relevant is that FERC's reliability jurisdiction, and thus NERC's authority, are limited to the bulk power system. Therefore, the following statement on page 3 of the White Paper needs to be revised:

While qualifying Generator Owners and Generator Operators can be classified as owning and operating electric transmission Elements and Facilities, these are most often not part of the integrated bulk power system, and as such should not be subject to the same level of standards applicable to Transmission Owners and Transmission Operators who own and operate transmission Facilities and Elements that are part of the integrated bulk power system.

Mandatory reliability standards—even a lower level of standards—cannot apply to non-BPS elements. It would be more accurate to state that generator leads do not exhibit many of the characteristics, such as integration, that require application of the full set of TO/TOP reliability standards to most transmission.

We believe that generator leads that are needed for reliability are already considered part of the BES because they are not "radials serving only load." Under Order 743, the BES must

include whatever is “necessary for reliable operation of an interconnected transmission grid,” which likely means that those generator leads that connect BES generators will continue to be part of the BES. Therefore, the issue facing the GO/TO team is primarily one of registration, not BES definition: BES generator interconnection facilities should be considered BES Facilities as they are now, but where the generator lead is owned/operated by the GO/GOP (which is not always the case), it should be included in the GO/GOP’s registration and should not subject the GO/GOP to registration as a TO/TOP. Note that BES Definition SDT is not assigning responsibility for BES Facilities to one functional entity or another.

We note in addition that the White Paper’s statement that “[w]hile not all power plants are considered part of the Bulk Electric System, ultimately, all the plants are interconnected to the bulk power system *via their generator interconnection facilities*” (emphasis added) is incorrect due to the italicized language. In fact, some plants are connected to distribution or non-BES sub-transmission and are not connected to the bulk power system or BES through their interconnection facilities.

TAPS’ overarching concern is that a system that only owns a minor component of a generator lead should only be registered and made responsible for those requirements and measures of standards that properly apply to that component.

#### ***B. Standards***

TAPS is comfortable with the White Paper’s elimination of many of the standards revisions that had been included in the GO/TO Ad Hoc Group Final Report. We believe that clarifying that (a) generator leads connecting BES generators are BES Facilities, and (b) such generator leads are included in the GO/GOP responsibilities of the owner and operator of the generator, will eliminate much if not all of any reliability gap that exists.

Furthermore, there is no need to revise FAC-003 so that it applies to generator interconnection facilities. A radial line cannot cascade, so the only effect of the radial generator lead sagging into vegetation is that the generator becomes unavailable. Because generators become unavailable for other reasons that dwarf the incidence of unavailability due to line outages, and the generator’s unscheduled unavailability is therefore planned for, no reliability purpose would be served by applying FAC-003 to generator interconnection facilities.

**Michelle D'Antuono, Occidental Energy Ventures Corp**  
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## **COMMENTS:**

### **Occidental Energy Ventures Corp. Comments on NERC Project 2010-07 White Paper Proposal on Generation Requirements at the Transmission Interface (GRTI)**

Occidental Energy Ventures Corp. ("Oxy:") commends the GRTI Standard Drafting Team (and the previous Ad Hoc GOTO group) for its efforts to define the NERC Standards requirements that should apply to generation interconnection facilities and offers the following answers to the questions posed in the informal comments announcement:

**The Ad Hoc group originally proposed the new terms "Generation Interconnection Facility" and "Generation Interconnection Operational Interface" as part of this project. The Project 2010-07 drafting team believes that the changes in the definition under Project 2010-17 and modifications to a select group of standards can accomplish the same goal without the need for new definitions. Do you support this approach? If not, please explain.**

1. Coordination Between Standard Drafting Teams. Based on the current status of the Bulk Electric System Standard Drafting Team (BESSDT) proposed BES definition, the White Paper Proposal ("Proposal") does not provide a clear demarcation between generator interconnection facilities and the interconnected transmission facilities of the Transmission Owner/Operator. The current BES definition makes no mention of what is or is not generation interconnection facilities, but merely includes "generating units greater than 20 MVA (aggregated 75 MVA at one site) from the generator terminals through the GSU which has a high side voltage of 100 KV or above." Many such registered generators have an additional interconnection line that is above 100 KV that, in turn, connects the generator to the transmission owner's facilities and is part of the generator interconnection. The currently proposed BES "core definition" would classify this line as a Transmission Element and might be construed as subjecting the GO to the full array of TO/TOP standards for this interconnection line. This outcome would violate the stated purpose of the Proposal. According its scope, the BESSDT is looking to the GRTISDT to define this demarcation either through a definition, as proposed by the Ad Hoc group, or by some other means. As Oxy interprets its scope, the BESSDT is defining what is or is not part of the BES without defining what standards apply to different parts of the BES, or, for that matter, what standards apply to non-BES facilities.

2. Generation Interconnection Lines. Oxy basically disagrees that generation interconnection lines are transmission lines from a functional standpoint. The interconnection line's function is to interconnect the generator (i.e., generally radial in nature) with the transmission system. The transmission system function is to deliver the generation to the load. That is not to say that some standards related to higher voltage lines may apply. Merely that, from a functional standpoint, the two are not the same and the reliability requirements are not the same.

**How can the proposal outline in the White Paper be improved. Is the drafting team headed in the right direction?**

In general, the approach outlined in the White Paper needs more clarity concerning exactly what requirements will apply to the essentially radial systems connecting generation to the transmission system. This needs to be very clear. Oxy suggests that the Ad Hoc approach of defining Generation Interconnection Facilities be adopted by the drafting team (although the Ad Hoc definition is probably not adequate). The drafting team will then have to decide whether their proposed definition provides enough clarity such that there will be no doubt that most of the TO/TOP standards do not apply to these facilities. The TO/TOP standards that would apply to interconnection facilities would then be treated individually with new/revised requirements.

1. Proposed FAC-001 Revisions. The proposed addition of R4 and M4 in FAC-001 seems to be stated in reverse. Wouldn't the normal procedure be for the GO to submit an interconnection request to the TO as part of entering into an interconnection agreement? The procedure required of the TO in R1 through R3 specify what the TO's requirements are for interconnection. As an aside, as these procedures are changed or updated, there needs to be some requirement for communication of the changes. Also, Oxy questions the 45 day requirement. How could all the requirements in the interconnection procedure be accomplished in 45 days? The drafting likely has some underlying assumptions that are not apparent and need clarification.
2. Proposed FAC-003 Revisions. Oxy agrees with the Ad Hoc Group's Proposal 2 which provides for exclusions for short distance interconnections, i.e., interconnection lines that do not exceed two spans (or some reasonable distance that can be monitored visually or with cameras) from the generator's property line. In addition, there should be a process for demonstrating to the Regional Entity that the interconnection line has no vegetation around it to manage, i.e., in arid or industrial locations.

**Do you have any further suggestions for seeking industry input before the project moves into a more formal development phase?**

Oxy feels the comments on the Ad Hoc group report and the comments on the Proposal provide sufficient information for the drafting team to commence formal development. Although this project is extremely important, the formal process should not be shortened by classification as urgent.

**Greg Rowland, Duke Energy Corporation**  
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## **COMMENTS:**

Below are Duke Energy comments on the currently posted White Paper:

### **Questions posed on the NERC Announcement, and Duke Energy Responses**

1. How can the proposal outlined in the White Paper be improved? Is the drafting team heading in the right direction?

Response: Duke Energy agrees with the approach outlined in the White Paper, which is to rely on the definition of Bulk Electric System (now being revised on Project 2010-17) to ensure that all BES facilities are appropriately identified for applicability of reliability standards. This is a much cleaner approach than the previous effort. We appreciate the work of the Standard Drafting Team to use this targeted approach to identifying the specific reliability standards which should be applied to Generator Owners and Generator Operators for their BES interconnection facilities.

2. The drafting team has chosen to use informal means of receiving industry feedback (webinars, presentations before industry stakeholder groups, etc.) prior to expending valuable industry resources to develop specific proposals for reliability standard requirements, measures, VSLs, etc. Do you have any further suggestions for seeking industry input before the project moves into a more formal development phase?

Response: No further suggestions for seeking industry input.

3. The Ad Hoc group originally proposed the new terms “Generator Interconnection Facility” and “Generator Interconnection Operational Interface” as part of this project. The Project 2010-07 drafting team believes that changes to the definition of Bulk Electric System under Project 2010-17 and modifications to a select group of standards can accomplish the same goal without the need for new definitions. Do you support this approach? If not, please explain.

Response: Duke Energy agrees that the previously proposed new defined terms are not needed. Project 2010-17 is developing a definition for Bulk Electric System (BES) that uses a bright-line criteria of 100 kV and above, and an inclusion/exclusion process to address specific facilities. This will ensure that BES interconnection facilities are appropriately identified. If Project 2010-07 then identifies any modifications to the reliability standards needed to address specific responsibilities of Generator Owners and Generator Operators to BES interconnection facilities, then no “reliability gap” will exist.

**Kenneth A. Goldsmith P.E., Alliant Energy**  
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## **COMMENTS:**

We have one comment concerning making a Generator Owner (GO) subject to the requirements of FAC-003 Transmission Vegetation Management. We can understand the need to have long highvoltage radial lines from a generating station to the interconnection point of the BES be included in the requirements for FAC-003. Our concern lies with the lines from a central generating station GSU, normally located just outside the generator building to the substation which may not be directly adjacent to the power block. These lines typically remain within the generating station boundaries, so we believe Article 4.2.4 of FAC-003-2 should be revised to read : “. . . located outside the fenced area of the switchyard, **generating station property** or substation and any portion of the span of the . . .”. This would clarify that only lines outside of the generating station property would be applicable.

**Lee Pedowicz, NPCC**  
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**COMMENTS:**

Below are NPCC's comments for Project 2010-07 - Generator Requirements at the Transmission Interface - Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR Standards. The table lists the NPCC member contributors to these comments.

	<b>Member</b>	<b>Organization</b>	<b>Region</b>	<b>Segment Selection</b>
1	Adamson, Alan	New York State Reliability Council, LLC	NPCC	10
2	Guy Zito	Northeast Power Coordinating Council	NPCC	10
3	Campoli, Gregory	New York Independent System Operator	NPCC	2
4	Chong, Kurtis	Independent Electricity System Operator	NPCC	2
5	Clermont, Sylvain	Hydro-Quebec TransEnergie	NPCC	1
6	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
7	De Graffenried, Chris	Consolidated Edison Co. of New York, Inc.	NPCC	1
8	Dunbar, Gerry	NPCC	NPCC	10
9	Evans-Mongeon, Brian D.	Utility Services	NPCC	8
10	Garton, Mike	Dominion Resources Services, Inc.	NPCC	5
11	Gooder, Brian L.	Ontario Power Generation Incorporated	NPCC	5
12	Goodman, Kathleen	ISO - New England	NPCC	2
13	Haswell, Chantel	FPL Group, Inc.	NPCC	5
14	Kiguel, David	Hydro One Networks Inc.	NPCC	1
15	Lombardi, Michael R.	Northeast Utilities	NPCC	1
16	MacDonald, Randy	New Brunswick Power Transmission	NPCC	1
17	Metruck, Bruce	New York Power Authority	NPCC	6
18	Pedowicz, Lee	NPCC	NPCC	10

19	Pellegrini, Robert	The United Illuminating Company	NPCC	1
20	Saksena, Saurabh	National Grid	NPCC	1
21	Schiavone, Michael	National Grid	NPCC	1
22	Sipperly, Wayne	New York Power Authority	NPCC	5
23	Weaver, Donald	New Brunswick System Operator	NPCC	2
24	Wu, Ben	Orange and Rockland Utilities	NPCC	1
25	Phan, Si Truc	Hydro-Quebec TransEnergie	NPCC	1

It is missing a logistical requirement between FAC-003 and FAC-014. There is nothing in either standard where the PC is informing the TOs and GOs of the applicability of their facilities as outlined in the Facilities section 4.2.2 of FAC-003.

- On page 3 of the White Paper, the SDT referred to “qualifying” generator interconnection facilities. It is not clear what are the qualifying criteria. Are the qualifying criteria for Elements and Facilities the BES definition criteria? If so, this should be stated explicitly.

- The proposed definition of Generator Interconnection Operational Interface was “Location at which operating responsibility for the Generator Interconnection Facility changes between the Transmission Operator and the Generator Operator.” Why was this definition removed? It does not refer to Elements and Facilities rated at 100 kV and above. It is also unclear how the original objective meant to be achieved by the proposed change to EOP-008-0 R1.3 would be met. This needs clarification.

- In FAC-001-0, suggest that R4 be modified as follows: start the sentence with “The” and delete “be required to”.

- The modification in FAC-001 for a Generator Owner is not necessary. It is understood that a generator’s output connection to the transmission system must comply with the “receiver’s” requirements.

- Interconnection request needs to be defined. In R4, why does the Generator Owner receive an interconnection request?

- The last sentence of footnote 2 of FAC-003 should also be modified to include the Generator Owner.

- For FAC-003, this appears to be a standard applicability and registration issue. It may be more appropriate to define transmission in such a way that any generation owner that happens to also own BES transmission must register as such. With the coming of the new BES definition perhaps that would be the opportune time to introduce a fix for this registration issue. It is suggested that with the upcoming changes to the BES definitions this project should be on hold, with the understanding that the registration issue be examined.



**John Bee, Exelon Transmission Strategy & Compliance**  
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## COMMENTS:

### Project 2010-07 Exelon Comments

#### FAC-003

1. The SDT should include a unique schedule and guidance specifically for GO implementation of this standard.
2. The standard should provide a clear provision to allow incorporating GO owned facilities within an existing TO's vegetation management program if mutually agreed on by the TO and GO.
3. Please provide more clarification regarding FAC-003 Requirement 4.2.4. The rationale explains that areas within the fenced area of a switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence are excluded; however, there is no guidance regarding transmission lines that run between a generator main power step up transformer and an onsite switchyard. Is the intent to include transmission lines on station property that run between a generator main power step-up transformer and an onsite switchyard?
4. Exelon suspects that this standard work is being done due to issues with GOs that have long generator leads running miles rather than feet. The standard should have verbiage stating that the standard is not applicable to GOs with short generator leads. The SDT should define "long leads" based on the length of the conductor and have provisions to exclude generators with "short leads"

#### FAC-001

1. Exelon does not agree that this standard should not be broadly applied to GO. GOs who do not own a switchyard and whose point of interconnection is a disconnect switch associated with the generator leads prior to the switchyard should be excluded from this standard. If a group of GOs share a generator tie line, then the associated Interconnect Agreement that each of the GO has with the applicable TO and/or TOP should address how these shared connections will effect the system. GOs may not have the resources or expertise to conduct the required interconnect studies to meet this standard
2. Exelon has generating stations that have the Main Power Transformer (MPT) disconnect as the point of demarcation. The station owns the short leads from the MPT disconnect back to the generator and the applicable TO owns from the MPT disconnect up to and including the switchyard. It is not practical for another entity to request to interconnect to the MPT disconnect nor should it be allowed. The SDT should consider verbiage to the standard that does not allow requests to interconnect to a MPT disconnect.
3. Exelon is having difficulty determining how this standard would apply to GOs and how GOs would implement the standard; suggest that examples be provided in an implementation document specifically showing where and how this standard would apply.

**Patti Metro, National Rural Electric Cooperative Association (NRECA)**

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**COMMENTS:**

Drafting Team Members,

The National Rural Electric Cooperative Association (NRECA) thanks the team for this opportunity to provide comments to its white paper. Although, NRECA supports clarifying the responsibilities of entities that own/operate transmission and/or generation intertie/interconnection facilities, until the definition of the Bulk Electric System under Project 2010-17 is developed it is difficult to rectify these issues. The team should carefully monitor the Project 2010-17 activities to ensure that it does not adversely affect the success of the project nor develops requirements or definitions that would contradict the criteria established in Project 2010-17. At this time, NRECA does not have a specific position on these issues, but looks forward to reviewing and commenting on future documents this team posts for stakeholder comment.

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## COMMENTS:

Re: Project 2010-07 Generator Requirements at the transmission interface. Informal comment period

EquiPower Resources Corp., its subsidiaries Dighton Power, LLC, Lake Road Generating Company, L.P., MASSPOWER, Milford Power Company, LLC and its affiliate, Empire Generating Co, LLC (collectively “EquiPower”) are pleased to submit these informal comments to the Project 2010-07 Standard Drafting Team (SDT). EquiPower own and operates five (5) power plants located in Massachusetts, Connecticut and New York that are individually registered as Generator Owners (GO) and/or Generator Operators (GOP).

EquiPower generally supports the SDT’s approach presented in its White Paper and believes the SDT is heading in the right direction. The recommendations appear to be reasonable. In particular, we support the following concepts and recommendations:

- Neither a GO or GOP should be required to automatically register as a Transmission Owner (TO) or Transmission Operator (TOP) simply because it owns and/or operates generator interconnection facilities. Clarification of the fact that generator interconnection facilities are not part of the integrated transmission system or grid is crucial to resolving the treatment of GO/GOP interconnection facilities.
- Subjecting a GO/GOP to all requirements in the TO/TOP standards is impractical and an inefficient use of resources and will not have the desired effect of improving the reliability of the Bulk Electric System (BES).
- We support the recommended plan to modify a selected group of standards to make them applicable to GO/GOP’s as they relate to their generator interconnection facilities. Subject to the considerations described below, EquiPower supports the modification of both FAC-001-0 *Facility Connection Requirements* and FAC-003-2 *Transmission Vegetation Management Program*.
- EquiPower agrees that GO/GOP personnel training should be addressed in a future project.

EquiPower has two concerns that it asks the SDT to consider.

- First, as proposed in the GOTO Ad Hoc Group's Final Report, EquiPower feels strongly that including a defined span criteria at FAC-003-2 is important. Many generating plants have a nominal length of overhead tie line extending from the generator step-up (GSU) transformer substation to the interconnection point with the integrated transmission system. Requiring a GO to have a vegetation management plan for such a nominal length of conductor is not practical or efficient, nor does it provide any discernible benefit in terms of improving the reliability of the BES.
- Second, we are concerned about the regulatory implications associated with the identification of generator interconnection facilities as transmission facilities or elements. The proposed addition of Generator Owner to FAC-003-2 is similar to the applicability language found in PRC-023-1 *Transmission Relay Loadability*. Yet in Order 733 FERC concluded that, in the majority of cases, a GO would not be subject to the standard since the GO would also need to be registered as a TO, which FERC acknowledged is uncommon. The reasoning applied in Order 733 seems to focus on the term "transmission lines" and that a transmission line owner, irrespective of integrated versus non-integrated status, would need to register as a TO. EquiPower would encourage the SDT to fully consider the implications of Order 733 as it applies to GOs and clarify the application of the term "transmission lines." It is fundamentally important that the use of the term "transmission lines" clearly distinguish between integrated and non-integrated applications.

EquiPower appreciates the opportunity to submit these comments. The use of informal means of communicating such as stakeholder webinars, meetings and comment submission are effective and efficient tools for communication and standard development.

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## **COMMENTS:**

Following are the comments for Consumers Energy (NCR00740) regarding Project 2010-07. Problems are created with the interchangeable use of "BES" and "transmission." NERC should maintain consistency with the use of BES, Transmission, transmission, distribution, etc. When a capitalized term is used it should be consistent with the NERC Glossary. Maybe a note should also be provided to denote that the use of the term transmission and distribution specifically do not refer to any defined system and are only used as part of the English language. When a term is used in a standard maybe it should be used consistently throughout the standard to avoid confusion. If it changes, even slightly, say to Bulk Power System (BPS) it should be accompanied with an explanation why the term being used is different. Transmission is defined by the FERC Seven Factors and by what has been authorized by the regulating State body and the FERC as being Transmission. The term Transmission defined for rate making purposes and Transmission systems vary significantly across the country to voltage levels much less than 120kV. Therefore, the use of the term Transmission and the word transmission should not be used to define facilities covered under NERC Reliability Standards. Adding Registered Entities (GO/GOP/DP) to standards involving BES facilities should be allowed to ensure the full coverage of BES facilities for the NERC Reliability Standards.

**Joseph DePoorter, Madison Gas and Electric Company**

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**COMMENTS:**

Within the Project 2010-07's White Paper, it should be noted that many GO's has established and detailed Interface agreement concerning their Transmission Interfaces. This White Paper did not clearly address those in place agreements. Recommend that this fact be highlighted going forward in any such White Paper, Guideline, Rational box, etc.

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## COMMENTS:

The Midwest Reliability Organization's NERC Standards Review Subcommittee submits the following comments on the white paper titled "Project 2010-07: Generator Requirements at the Transmission interface":

**SDT Question #1a:** How can the proposal outlined in the White Paper be improved?

### NSRS Responses:

Next Step #1 - According to FERC Docket #ER10-1117, if a Generator Owner receives a request for service over their facilities; they have 60 days to file a tariff for processing the request for service. So, we think that the proposed Requirement R4 of FAC-001 should give the Generator Owner 60 days, rather than 45 days, to provide its interconnection requirements.

Next Step #3 – NERC has not clearly defined wind farms to be generating plants. So, the words, "directly connected via a step-up transformer(s) to Transmission Facilities operated at voltages of 100 kV or above", in the latest Project 2010-17 concept paper may not be interpreted as applicable to wind farms. The generating units of wind farms are typically directly connected to subtransmission facilities, which in turn are directly connected to Transmission Facilities operated at voltages of 100 kV or above.

Other proposed changes – in the paragraph about EOP-003-1 on page 6 we agree that Generator Operators should not be added to EOP-003-01, but for a different reason. When the proposed EOP-003-2 is approved and becomes effective, all of the requirements associated with the UFLS programs will be removed. We don't agree that PRC-001 already properly addresses the coordination of the generator UF protection with the UFLS program. However, we understand that the proposed PRC-024-1 will be the standard that contains the requirements for the Generator Owners to coordinate generator UF with UFLS program.

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**SDT Question #1b:** Is the drafting team heading in the right direction?

**NSRS Response:** Yes, the drafting team is heading in the right direction.

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**SDT Question #2:** The drafting team has chosen to use informal means of receiving industry feedback (webinars, presentations before industry stakeholder groups, etc.) prior to expending valuable industry resources to develop specific proposals for reliability standard requirements, measures, VSLs, etc. Do you have any further suggestions for seeking industry input before the project moves into a more formal development phase?

**NSRS Response:** No

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**SDT Question #3:** The Ad Hoc group originally proposed the new terms "Generator Interconnection Facility" and "Generator Interconnection Operational Interface" as part of this project. The Project 2010-07 drafting team believes that changes to the definition of Bulk Electric System under Project 2010-17 and modifications to a select group of standards can accomplish the

same goal without the need for new definitions. Do you support this approach? If not, please explain.

**NSRS Response:** Yes



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## **COMMENTS:**

FAC-003 should not be applicable to Generator Owners / Operators. The intent of all of the standards is to avoid an Adverse Reliability Impact, or as the FPA Section 215(a)(4) defines "reliable operations" as: "operating the elements of the bulk-power system within equipment and electric system thermal, voltage and stability limits so that instability, uncontrolled separation, or cascading failures of such systems will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements." Radial Facilities serving only generating plants when tripped will not threaten an Adverse Reliability Impact or we would be hard pressed to run that generation in the first place. FMPA believes the intent of the standard is to prevent a cascading event where, if a line trips, another line loads heavily increasing the sag of that line, which may sag into un-cleared vegetation, causing the second line to trip, which may in turn cause heavily loading on a third line, etc. If a line trips in the transmission network, radial Facilities from generating plants will not have their loading changed much at all (since they are radial) and will not participate in this sort of "thermal" cascading event. Hence, there is no cause to regulate vegetation management of radial Facilities to generating plants since the system is always planned and operated to that potential contingency anyway and there is no danger of an Adverse Reliability Impact. Regulating vegetation management on radial Facilities is beyond the scope of the Federal Power Act Section 215. Generator Owners / Operators are still incited to perform adequate vegetation management without the need for regulation because any outage of the plant results in lost opportunity costs to the plant.

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**COMMENTS:**

**Project 2010-07 Generator Requirements at the Transmission Interface  
 Attendance**

*Participants that Added Their Name to Comment Form*

Group Comments (Complete this page if comments are from a group.)			
<b>Group Name:</b>	<b>SPP Standards Development</b>		
<b>Lead Contact:</b>	<b>Robert Rhodes</b>		
<b>Contact Organization:</b>	<b>Southwest Power Pool (SPP)</b>		
<b>Contact Segment:</b>	<b>2</b>		
<b>Contact Telephone:</b>	<b>501-614-3241</b>		
<b>Contact E-mail:</b>	<b>rrhodes@spp.org</b>		
<b>Additional Member Name</b>	<b>Additional Member Organization</b>	<b>Region*</b>	<b>Segment*</b>
Craig Henry	Oklahoma Gas & Electric	<b>SPP</b>	1,3,5
Michelle Corley	Cleco	<b>SPP</b>	1,3,5
Louis Guidry	Cleco	<b>SPP</b>	1,3,5
Sean Simpson	Board of Public Utilities, City of McPherson, Kansas	<b>SPP</b>	1,3,5
Harold Wyble	Kansas City Power & Light	<b>SPP</b>	1,3,5
Alan Burbach	Lincoln Electric System	<b>MRO</b>	1,3,5
Gary Tarplee	Eddington Mission Marketing & Training	<b>SPP</b>	5,6
Mark Wurm	Board of Public Utilities, City of McPherson, Kansas	<b>SPP</b>	1,3,5
Stephen Layton	Mustang Station	<b>SPP</b>	
Rick Koch	Nebraska Public Power District	<b>MRO</b>	1,3,5
Anthony Cassmeyer	Western Farmers	<b>SPP</b>	1,3,5

Eddie Perez	Wind Capital Group	<b>SPP</b>	

FAC-001: What gaps have been identified? Since Generator Owners do not have a tariff how would a GO determine what a valid interconnection request would be? The generator Owner wouldn't have the jurisdiction to accept an interconnection request any more than a land owner would. What is the basis for making the Generator Owner the valid entity for accepting a request.

FAC-001 R4: This states that the Generator Owner must post within 45 days for an interconnection request but the request should be a valid request. Generation Owners would not be a valid entity to accept a generation interconnection request all requests should be submitted through the TSP. Shouldn't the TSP then provide notification to the GO when interconnection request are received to interconnect with GO's generation facilities? There are processes in place currently that handle valid interconnection requests and this requirement seems to violate those processes. Could the Generator Owner deny the request for interconnection on his behalf? Since interconnection service only provides interconnection to the Bulk Electric System and not transmission service how then will they acquire transmission service? This requirement seems to conflict with current processes already in place.

FAC-003: Would like an expansion in the rationale behind why FAC003-2 should apply to ties outside of the fence. It is in the best interest of the Generator Owner to take care of vegetation from his facility to the BES in order to sell power.

BES Team: Would ask that the SDT would coordinate with the 2010-17's SDT and keep these tied together.

**Cindy Martin, Southern Company**

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## **COMMENTS:**

Mallory, please accept the below comments from Southern Company regarding Project 2010-07 White Paper: **Generator Requirements at the Transmission Interface:**

SoCo Gen Comments to Project 2010-07 White Paper:

### **Generator Requirements at the Transmission Interface**

23 Mar 2011

#### **General**

We commend the effort directed towards the clarification of the application of NERC standards to generation interconnection circuits ("extension cords").

We agree completely with the following observations made on pages 2 and 3 of the White Paper Proposal:

Power plants come in many sizes and configurations.

The (GOTO Ad Hoc Group) plan of proposing new definitions, modifying other definitions, and making changes to dozens of standards is not necessary.

GOs and GOPs owning and operating electric transmission Elements and Facilities are most often not part of the integrated bulk power system, and as such should not be subjected to the same level of standards applicable to TOs and TOPs. [integrated implies networked, "extension cord" implies radial]

Requiring any classification that subjects GOs and GOPs to all the standards applicable to TOs and TOPs would do little to improve the reliability of the BES.

Applying all standards applicable to TOs and TOPs to non-networked/non-integrated transmission circuits would have little effect on the overall reliability of the BES.

Changes to the definition of the BES and modifications to a select group of standards can accomplish the goal without the need for new definitions.

#### **FAC-001 R4**

Please make it clear that the interconnection request is meant to be addressing a new connection to the high voltage (>100kV) "extension cord" circuit owned by the Generator Owner.

The connection of additional generation or load to the "extension cord" generation interconnection facility (circuit) changes the face of the non-radial nature of these circuits. It is not clear that only FAC-001 and FAC-003 should be applicable to the GO/GOP with this interconnect. Would the GO/GOP with networked transmission facilities be subjected to additional (traditional) TO/TOP standard requirements? If so, this project should include a review of those standards in the project scope.

Is the TO subject to completing R1, R2, and R3 within 45 days of receiving the interconnection request? If not, should the GO be subject to that time constraint?

### **Project 2010-07 Purpose**

One of the two purposes of the Project 2010-07 is stated as “identify all generator-owned facilities that are considered part of the BES” and “clearly identify the appropriate generation Facilities.”

Please focus on this identification process. This effort should ensure clarity in the scope of application to GOs to avoid confusion and additional work load on GOs that do not contribute to the reliability of the BES. We are concerned that the modified BES definition may make the GO/GOP entities responsible for additional existing standards. A very clear description is needed to identify which GO/GOP owned “extension cord” circuits are included. Also, there is a need for itemizing any additional GO/GOP requirements resulting from a redefinition of the BES or from changes to existing standards. These clear descriptions will help eliminate uncertainty regarding the scope of equipment that is in the scope of NERC reliability standards.

Was any consideration given to creating a comprehensive listing of all NERC reliability standard requirements for owners of these “extension cord” circuits? A document of this type would provide GO/GOP owners of these circuits the ability to determine precisely which standards apply to that equipment.

### **FAC-003-2**

FAC-003-1 R1 should not include GO as generation interconnection facility (“extension cord”) because they are never an IROL circuit.

**Thomas E. Foltz, American Electric Power**

Reliability Standards Compliance  
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**COMMENTS:**

American Electric Power (AEP) appreciates the opportunity to provide input to the draft of "Project 2010-07: Generator Requirements at the Transmission Interface", and offers the following response for consideration.

AEP endorses the collective prior work of this group, however this effort needs to be done in coordination with concurrent efforts already underway within NERC, in defining and re-defining definitions that fall within the scope of the Bulk Electric System. It is unclear if lines are being drawn to somehow delineate between what might be considered as the transmission portion of the bulk electric system and what might be termed the generation bulk electric system.

We believe the group is heading in the right direction, however, in its implied desire to streamline the required changes recommended by the GOTO Ad Hoc Group (by eliminating the definition of Generation Interconnection Facility), it is now less clear where the planning and operational responsibilities reside for the high voltage generator lead from the GSU to the transmission point of interconnection. For example, page 3 of the White Paper states that the SDT believes it is appropriate to classify various generating Facilities and Elements (including generator interconnection facilities) as part of the Bulk Electric System. We agree. The SDT also states that it believes that qualifying generator interconnection facilities should be classified as transmission. We do not agree with leaping to classify the qualifying generator interconnection facilities as transmission absent further clarification, particularly with respect to the definition of Generation plants that is the subject of Project 2010-07 as explained in section 3 of the White Paper. Item 3 of section 3 states the following:

“Generating plants (including GSU transformers and the associated generator interconnection line lead(s)) with aggregate capacity greater than 75 MVA (gross nameplate rating) directly connected via a step-up transformer(s) to Transmission Facilities operated at voltages of 100 kV or above:”

Item 3 helps to clarify what qualifying generation interconnection facilities fit within the Bulk Electric System definition, but it is not at all clear from item 3 that the generation interconnection facility should be classified at transmission. Indeed, the foregoing generating plant definition would appear to be at odds with the SDT view.

This lack of clarity then brings into question the SDT groups conclusion that the “changes listed above mark a significant decrease in changes originally proposed by the GOTO Ad Hoc Group in its Final Report”. In particular, clarifications to the definition of Bulk Electric System eliminate the need for the GOTO Ad Hoc Group’s suggestions to include a reference to the proposed new term “Generator Interconnection Facility” in the following standards referenced in the GOTO Ad Hoc Group Final Report: BAL-005-0.1b, CIP-002-1, EOP-001-0, EOP-004-1, FAC-008-1, FAC-009-1, IRO-005-2, MOD-010-0, MOD-012-0, PRC-004-11, PRC-005-1, TOP-002-2, TOP-003-0, VAR-001-1, and VAR-002-1.

While AEP agrees in principle that it is desirable to reduce the need for modifications to existing Standards, we do not yet agree that the SDT’s White Paper brings enough clarity to reach the conclusion that modifications to one or more of the foregoing Standards are not required. The following comments are directed to the revisions the SDT team recommends to the following Standards.

**FAC-001**

There are substantial reliability issues, as well as additional regulatory, tariff, coordination, and

generator and interconnection facility issues, which need to be dealt with before AEP could agree to such requirements. It is not clear that a generator can receive a request for interconnection. Typically Generation Owners and/or developers make request for generation interconnection but do not have OATT requirements or processes in place to receive requests for generation interconnection. A material matter relating to the R4 requirement as defined by the SDT is whether a generator has any obligation to interconnect a new generation facility to its high voltage generation interconnection facility. This again points back to the SDT's blanket statement that the BES qualified generation interconnection facility be classified as "transmission". We are not convinced this declaratory statement comports with OATT and/or RTO generation interconnection procedures. Furthermore, it would be onerous to expect a generator to agree to R4 since generators are not in a position to comply with R1, R2 and R3.

FAC-001 R4

Regarding "Generator Owner that receives an interconnection request for its facility shall, within 45 days of such a request, be required to comply with requirements R1, R2, and R3 for the facility for which it received the interconnection request." Requirements R1, R2 and R3 refer to Transmission Owner's connection requirements. The proposed R4 as written implies the Generation Owner that receives an interconnection request for its facility (what facility?) will comply with the Transmission Owner facility connection requirements. We don't see the linkage between the Generation Owner and the Transmission Owner and how this is enforceable given the barriers to collaboration between new and existing generators and transmission owners.

If an end user facility seeks to be served on the Generation side of an interconnect, shouldn't the request be coordinated through an entity such as the regional transmission entity, or the appropriate transmission owner or transmission operator?

FAC-003-2

The SDT recommendation to add the Generation Owner requirement is acceptable.

**Kasia Mihalchuk, P. Eng., Manitoba Hydro**  
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## COMMENTS:

**Manitoba Hydro's Comments on**  
**Project 2010-07 Generator Requirements at the Transmission Interface**  
**Informal Comment Period Open**  
**March 4 – April 4, 2011**

Comments:

**Question:** How can the proposal outlined in the White Paper be improved? Is the drafting team heading in the right direction?

**Response:**

Manitoba Hydro (MH) does not agree with the SDT position that qualifying generator interconnection facilities should be classified as part of the BES, but “That does not mean, however, that a Generator Owner or Generator Operator should be required to automatically register as a Transmission Owner or Transmission Operator simply because it owns and/or operates transmission Elements or Facilities”. The premise for adding Generator Owner to the applicability section of FAC-001-0 appears to be based on the presumed need to cover the situation where a generator owner receives a request to interconnect to a line owned by the generator. MH disagrees that this is even a feasible scenario. If the Generator is not a transmission owner or a transmission provider, what is the mechanism to implement such a request? The generator would have to be a transmission provider and offer a transmission tariff. All interconnection requests should be implemented by the Transmission Owner regardless if the interconnection point is within a GO facility or end-user facility. The TO is in the best position to set unbiased connection requirements to ensure the reliability of the BES is maintained. If a mechanism is created to allow interconnection to a BES line owned by Generator, then it is essential for this Generator providing this interconnection service to be a Transmission Owner to ensure all reliability standards, including the protection standards, are met so the reliability of the BES is maintained.

MH does not understand the SDTs rationale for the statement “Requiring any classification that subjects Generator Owners and Generator Operators to all the standards applicable to Transmission Owners and Transmission Operators would do little, if anything, to improve the reliability of the Bulk Electric System”. This statement is not consistent with the first sentence of the previous paragraph where the SDT states “The SDT believes it is appropriate to classify various generating Facilities and Elements (including generator interconnection facilities) as part of the Bulk Electric System”. If reliability is not impacted, why is it appropriate to classify various Generating Facilities and Elements (including generator interconnection facilities) as part of the BES? It is not logical to allow the Generator to be a



“partial transmission owner”. If the Generator has transmission which is part of the BES, and over which tariff service is provided, the Generator must be a Transmission owner. Consequently, there is no need to change the applicability of FAC-001-0.

**Question:** The drafting team has chosen to use informal means of receiving industry feedback (webinars, presentations before industry stakeholder groups, etc.) prior to expending valuable industry resources to develop specific proposals for reliability standard requirements, measures, VSLs, etc. Do you have any further suggestions for seeking industry input before the project moves into a more formal development phase?

**Response:**

We believe that the industry resources would be better served by reviewing and responding to a specific draft of a proposed standard rather than providing comments on a direction in which the SDT should proceed. If there is uncertainty as to what needs to be included in the standard, we question the need for the standard given the numerous other standard proposals in the NERC queue.

**Question:** The Ad Hoc group originally proposed the new terms “Generator Interconnection Facility” and “Generator Interconnection Operational Interface” as part of this project. The Project 2010-07 drafting team believes that changes to the definition of Bulk Electric System under Project 2010-17 and modifications to a select group of standards can accomplish the same goal without the need for new definitions. Do you support this approach? If not, please explain.

**RESPONSE:**

MANITOBA HYDRO SUPPORTS AN APPROACH WHICH RELIES ON THE DEFINITION OF THE BES, INCLUDING ANY EXCLUSION AND INCLUSION CRITERIA, TO DETERMINE THE FACILITIES THAT SHOULD BE PART OF THE BES. GIVEN THAT MANY GENERATORS ARE RADIAL CONNECTIONS TO THE BES, SPECIFIC CRITERIA NEED TO BE DEVELOPED TO INCLUDE THESE CONNECTIONS IN THE BES.

**Applicability of FAC-003-01**

**Comment:**

Does the SDT have data to quantify the number of miles of transmission lines 100 kV and above that can be attributed to “multiple generating units spread over several thousand acres”? Are these thousands of acres within station fences where vegetation can be completely managed by the Generator? How many vegetation contacts have been experienced on these generator interconnection lines? Vegetation management is more of an issue for a Transmission Owner who has 10’s of thousands of miles of lines and may not be able to inspect/maintain it all without a proper process. MH would recommend that Generator Owner not be added to FAC-003-2. If NERC decides to go in this direction then we question if radial lines connecting Load to the BES should be in the same category. Generator Owner’s may have more underground cables than overhead lines and outages due to cable faults could be more frequent than vegetation contact.

**Dan Roethemeyer, Dynegy**  
Dan.Roethemeyer@dynegy.com

## **COMMENTS:**

Per the March 4, 2011 email regarding informal comments for Project 2010-07 Generator Requirements at the Transmission Interface, I am submitting the following comments on behalf of Dynegy Inc.:

· **How can the proposal outlined in the White Paper be improved?** Overall, the team has done a good job isolating the possible additional Standards/Requirements to only those which could impact reliability of the BES. However, with respect to FAC-003-2, there should be exclusion criteria based on the length of the generator tie line since short tie lines are commonly inspected as part of regular/routine inspections of generating plant and/or substation facilities. As such, we suggest generator tie lines 1 mile in length or shorter be excluded from FAC-003-2.

· **How can the proposal outlined in the White Paper be improved?** With respect to inclusion in Standard FAC-001-0, Generators typically have no experience dealing with Interconnection requests. As such, we suggest the team consider allowing the generator 45 days to first meet with an appropriate member of the BES (or other applicable expert) to then subsequently develop the applicable documentation in R1, R2, R3 within an agreed to time between the parties.

Thanks for your consideration.

**Dan Duff, Liberty Electric Power**  
610-872-7585  
dduff@libgen.com

## **COMMENTS:**

First, let me state that the team has done an outstanding job on this White Paper. I believe the proposal will go a long way towards improving the reliability of the BES without imposing undue hardships on GO/GOP registrants.

That being said, I do object to the removal of the “two span” language from the proposal. In my particular circumstances (and I am sure I am not alone in this case) our interface is approximately 30 feet from our step-up transformer – measured horizontally, there is less than ten feet from transformer to interface. To burden us with the entire vegetation management program serves no reliability purpose, but does add a large paperwork burden. Restoring some kind of distance requirement would remove those unnecessary burdens, and increase the chances of this worthy effort being translated into an accepted standard.

**Gary Tarplee, Edison Mission Energy**  
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gtarplee@edisonmission.com

## **COMMENTS:**

**Thanks for the opportunity to provide comments on the White Paper. EME is very supportive of the direction of the proposed White Paper. It is more efficient to modify the existing Standards as compared to creating new Standards specifically for GO's and GOP's. We offer the following comments;**

- 1. It is imperative that the generation interconnection facilities and associated generation tie lines are not required to register as a TO and TOP regardless of voltage or line length.**
- 2. Generation interconnection tie lines should be identified as being outside the substation fence and should be exempt if less than 0.25 miles in length.**
- 3. The addition of the GO and GOP to IRO-005 may be redundant to TOP-001 R13. Please review. If the TOP has responsibility for the generation interface the GO and GOP should only have responsibility to inform the TOP when the GO's SPS or control equipment is non-automatic or the GOP is not able to implement a TOP operating procedure due to some event at the generating plant.**

**John Hagen, Pacific Gas and Electric Company**

415-973-7356

JHH4@pge.com

**COMMENTS:**

PG&E as both a Transmission Owner, Transmission Operator, Generator Owner and Generator Operator supports the proposed changes in the white paper.

**Jonathan Appelbaum, The United Illuminating Company**  
[jonathan.appelbaum@uinet.com](mailto:jonathan.appelbaum@uinet.com)

## COMMENTS:

March 24, 2011.

The following comments are submitted by the United Illuminating Company regarding Project 2010-07: Generator Requirements at the Transmission Interface White Paper Proposal .

- ◆ How can the proposal outlined in the White Paper be improved? Is the drafting team heading in the right direction?

UI does not agree with the direction and prefers the Ad hoc Group's approach to defining new terms. There are two base facts that this White Paper does not address. First, the NERC Statement of Registration Criteria establishes the criteria for identifying what entities are required to register for a particular function; and second once registered for a function all requirements for that function apply. The SDT is attempting to split the baby by stating a Generator Owner may own an integrated transmission element but is not required to register as a Transmission Owner.

On page 3 of the White Paper the SDT writes:

*'The SDT believes it is appropriate to classify various generating Facilities and Elements (including generator interconnection facilities) as part of the Bulk Electric System. The SDT also believes that qualifying generator interconnection facilities should be classified as transmission. That does not mean, however, that a Generator Owner or Generator Operator should be required to automatically register as a Transmission Owner or Transmission Operator simply because it owns and/or operates transmission Elements or Facilities. While qualifying Generator Owners and Generator Operators can be classified as owning and operating electric transmission Elements and Facilities, these are most often not part of the integrated bulk power system, and as such should not be subject to the same level of standards applicable to Transmission Owners and Transmission Operators who own and operate transmission Facilities and Elements that are part of the integrated bulk power system.'*

In this paragraph the SDT states that the Generator Owner owns transmission elements. This statement alone is sufficient to require registration per the NERC Statement of Registration Criteria. But the SDT states that contrary to the Registration Statement those owners of these facilities need not register as Transmission Owners. The SDT then argues that the facility is not part of the *integrated* bulk power system without providing any technical justification for the term "integrated transmission facility". These facilities are impacting the reliability of the bulk power system and therefore are integrated into its operation. The SDT has to explain why these elements are not integrated. The SDT then states that because these transmission elements are not integrated into the bulk power system that all reliability requirements should not apply. The SDT is creating rules without reference to prior precedent and NERC activities.

The difficulty lies in the lack of a functional entity identified for these tie-lines. The creation of the functional entity would then allow the Reliability Standards to be applicable to those entities.

To demonstrate the inferiority of the White Paper and its approach let's review PRC-004. The White Paper states that PRC-004 requires no modification because it already is applicable to Generator Owners. PRC-004 utilizes the terms "transmission Protection system" and "generator Protection System" thereby differentiating between the two types of Protection Systems. R1 applies to Transmission Owners and Distribution Providers and their transmission Protection system, while R2 applies to Generator Owners and their generator Protection Systems. A Generator Owner owning and operating a transmission element will not be required to report on misoperations and corrective action plans for misoperations of the transmission Protection System even though the transmission Protection System misoperations will as effectively interrupt the generator as misoperations on the generator Protection System.

- ◆ The drafting team has chosen to use informal means of receiving industry feedback (webinars, presentations before industry stakeholder groups, etc.) prior to expending valuable industry resources to develop specific proposals for reliability standard requirements, measures, VSLs, etc. Do you have any further suggestions for seeking industry input before the project moves into a more formal development phase?

Include Regional Entity Compliance Manager's to provide opinion on this approach.

I agree that the SDT needs to communicate and obtain support for its approach prior to developing Standards. I imagine there are strong advocates for each approach, GOTO and the SDT approach.

- ◆ The Ad Hoc group originally proposed the new terms "Generator Interconnection Facility" and "Generator Interconnection Operational Interface" as part of this project. The Project 2010-07 drafting team believes that changes to the definition of Bulk Electric System under Project 2010-17 and modifications to a select group of standards can accomplish the same goal without the need for new definitions. Do you support this approach? If not, please explain.

No. Project 2010-17 will not resolve the problem. The new definition of BES will identify those generator leads that are part of the BES. It will not resolve this issue because once those lines are identified a Transmission Owner and Transmission Operator are required to be assigned. The problem is in the Functional Model, the NERC Statement of Registration Criteria and the requirement that all Reliability Requirements apply to a Registered Entity.

**Steve Alexanders PE, Central Lincoln**  
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salexanderson@cencoast.com

## **COMMENTS:**

Please see <http://www.ferc.gov/whats-new/comm-meet/2011/031711/E-4.pdf>, page 30, paragraph 47.

The FERC statement “ The Commission clarifies that it was not our intent to disrupt the NERC Rules of Procedure or the Statement of Compliance Registry Criteria” does not support the SDT’s statement “Follow the Project 2010-17—Definition of Bulk Electric System and ensure that the responsibility for generator interconnecting line leads is appropriately and clearly assigned to Generator Owners and Operators.” While I fail to see how a redefinition of the BES could not affect the registry criteria that references it, I still suggest including a revision to the registry criteria to assure that GO/GOPs with interconnection facilities are not registered as TO/TOPs.

No affect on Central Lincoln, but we support the team’s intent and thought you should be aware of yesterday’s ruling.



**LARRY RODRIGUEZ, Entegra Power Services**

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## **COMMENTS:**

There is no question that the main focus of the Project 2010-07 SDT should be the assurance that all GIF are appropriately covered by the Reliability Standards. However, I would only ask that SDT members keep the following issues in mind to assure focusing on true reliability instead of possibly diminishing reliability in specific cases with unnecessary documentation and procedures:

1. Regarding FAC-001, many GIF are connected to the BES by very short lateral interconnections off the BES. In many cases we are talking about ¼ mile or less; sometimes only a few hundred feet. In these cases would there even be the physical possibility of an interconnection? Even an SPS or possible reactive device would surely be installed in the substation or switchyard on either side of the line. Therefore, should the SDT consider some qualifiers limiting the application of the FAC-001 requirements?
2. Regarding FAC-003, what if in the same ¼ mile or less mentioned above, the situation is one in which there are no trees, but only scrub brush under those very short interconnections. In addition, the corridor width is only 200ft. and the entire few acres are visible from the plant making for near daily inspection. And, let us not forget these entities have enormous incentives to absolutely assure no vegetation growth into their lines. Should there be the possibility of documenting with pictures such a situation while still providing a limited VMP appropriate to this situation?
3. Many of the GIF we are considering are IPPs whose purpose for existence is to provide reliable, clean, and efficient energy to the marketplace. In the cases of these generators with very short interconnections and very limited staff of operator/maintenance specialists, has the SDT considered that we might actually be “diverting” true reliability efforts like generating MW & MVAR and communication/coordination with the RC, BA, and TOP by burdening them with an unnecessary level of documentation/procedures commensurate with the actual situation?

**Greg Froehling, Green Country Energy**  
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## **COMMENTS:**

- The Ad Hoc group originally proposed the new terms “Generator Interconnection Facility” and “Generator Interconnection Operational Interface” as part of this project. The Project 2010-07 drafting team believes that changes to the definition of Bulk Electric System under Project 2010-17 and modifications to a select group of standards can accomplish the same goal without the need for new definitions. Do you support this approach?

**No let me explain.**

### **Proposed BES definition:**

**Generation plants (including GSU transformers and the associated generator interconnecting line lead(s)) with aggregate capacity greater than 75 MVA (gross nameplate rating) directly connected via a step-up transformer(s) to Transmission Facilities operated at voltages of 100 kV or above.**

**(Looking for “Bright Lines” Leaves an unclear delineation at the GSU end and Transmission facilities end. GSU needs to be addressed as Low and High sides, Transmission Facilities does not identify a responsibility change.)**

### **My Definition:**

**“Generator Interconnection Facility:**

**The Facilities from the high side of the Generation plant GSU operated at 100kV or above, to the point of connection to Transmission Facilities that delineates a responsibility / ownership change from Generator Owner to the Transmission Owner.”**

**( I see this as very bright lines for who is responsible for what)**

**Ken Parker, Entegra Power Group, LLC**  
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**COMMENTS:**

**FAC-001**

Consideration should be given for FAC-001 applicability for Generator Owners (registered entity) with  $\frac{1}{4}$  to  $\frac{1}{2}$  mile of transmission interconnection to the BES, serving no load, and without plans to solicit interconnection requests. It serves no reliability purpose to burden those entities with FAC-001 R1, R2 and R3 requirements. Is it correct to assume R4 would only apply when an interconnection request is received?

**FAC-003-2**

Consideration should be given for FAC-003-2 applicability for Generator Owners (registered entity) with  $\frac{1}{4}$  to  $\frac{1}{2}$  mile of transmission interconnection to the BES and serving no load. For example, we have a  $\frac{1}{4}$  mile interconnection that can be seen in its entirety from the facility administration building, from which visual inspections regularly take place. Does the SDT envision a simple one page TVMP when circumstances are as described here?

**Mace Hunter, PE, Lakeland Electric**  
863-834-6516  
Mace.Hunter@lakelandelectric.com

## **COMMENTS:**

### **1. Add “Generator Owner” to the Applicability section of FAC-001-0 and add a requirement and a measure to address the responsibilities specific to the Generator Owner.**

FAC-001-0—Facility Connection Requirements currently applies to Transmission Owners and addresses the need for Transmission Owners to establish facility connection and performance requirements. While the standard requires Transmission Owners to address connection requirements for “generation facilities, transmission facilities, and end-user facilities,” it does not address the requirements for a Generator Owner that has received a request for interconnection. The lack of such requirements for a Generator Owner’s Facility could result in gaps.

Therefore, the SDT proposes that “Generator Owner” be added to the Applicability section of FAC-001-0. It further proposes the addition of Requirement 4 and a corresponding measure:

**R4.** Generator Owner that receives an interconnection request for its facility shall, within 45 days of such a request, be required to comply with requirements R1, R2, and R3 for the facility for which it received the interconnection request.

**M4.** The Generator Owner that receives an interconnection request for its facility shall make available (to its Compliance Monitor) for inspection evidence that it met the requirements stated in Reliability Standard FAC-001-0 R4.

The way I read this proposal is that a GO has no obligation under FAC-001 until it receives an interconnection request then it has 45 days to provide the requestor the elements listed in R1 and R2. The GO should also have an obligation under R3 to maintain the facility connection requirements that it provided to the requestor.

In most cases the GO will be requesting an interconnection with a TO. I think FAC-001 works fine in this case. I also agree that a GO should comply with FAC-003 for longer generator leads between its step up T/F and the interconnection with its TO. The question is how long do the leads have to be before the FAC-003 standard becomes effective. Requiring a GO to have an VMP for a short line with no vegetation issues seems extreme.

I don’t think a GO would want to lose a generator (lose \$\$) due to a vegetation problem so he will have some type of program in place for a longer line. Food for thought.

**END OF SUMMARY**

## **Informal Comments on White Paper for Project 2010-07—Generator Requirements at the Transmission Interface**

The Project 2010-07—Generator Requirements at the Transmission Interface standard drafting team (drafting team) thanks all who provided comments during this stage of development. The [White Paper Proposal for Informal Comment](#) was posted for a 30-day informal public comment period from March 4, 2011 through April 4, 2011. The stakeholders were asked to provide feedback via email to the NERC Project Coordinator. 51 sets of comments were submitted.

[http://www.nerc.com/filez/standards/Project2010-07\\_GOTO\\_Project.html](http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html)

The SDT has completed the review of the informal comments from industry for Project 2010-07—Generator Requirements at the Transmission Interface. Each comment was reviewed and considered by the drafting team as it proposed modifications to FAC-001 and FAC-003 and developed the project’s background document, and it will continue to consider this stakeholder feedback as the project progresses. If a comment is not specifically addressed, it is likely because the drafting team has addressed it elsewhere or the comment did not add clarity or otherwise improve the quality of the proposed standards.

A majority of commenters supported the concepts in the white paper, which represent a focused but comprehensive approach to including responsibility for generator interconnection Facilities in NERC’s Reliability Standards. Most commenters agreed that the approach of developing specific changes to a limited number of standards was preferable to developing new definitions or revising existing definitions.

The drafting team received many comments on the general direction of the project:

- **Some suggested that an interim solution be implemented until the modified standards are approved.** The drafting team is providing input to NERC compliance staff upon request as it works toward an interim solution.
- **Some said that Generator Owners and Generator Operators that are radial in nature should not have to comply with any additional standards.** In this phase of the project, the drafting team’s goal was to identify and modify standards necessary to eliminate any reliability gaps related to extended generation interconnection Facilities. Ultimately, this shall prevent the registration of Generator Owners and Generator Operators as Transmission Owners and Transmission Operators. After review of all of the standards, the drafting team believes that it is appropriate to apply FAC-001 and FAC-003 to Generator Owners (in certain cases). This was confirmed by stakeholder comments during the informal comment period.
- **Some were concerned with the drafting team’s use the term “transmission” to label generator interconnection Facilities.** Several commenters were concerned with the use of “transmission lines” as a label for generator interconnection Facilities. While such a label has been applied in other contexts by certain entities, the drafting team has avoided that labeling in its modifications to FAC-001 and FAC-003 and its background documents.

- **Some were concerned that the white paper did not acknowledge interface agreements.** The drafting team recognizes that interface/interconnection agreements usually have explicit language about coordination between Generator Owners and Operators and Transmission Owners and Operators, but unfortunately these agreements are not viewed by regulatory authorities as a tool that can be used for meeting reliability standards.
- **Some encouraged the SDT to revisit certain standards that already apply to Generator Owners and Generator Operators because some standards split requirements by applicable entity.** The drafting team has reviewed the standards that already include Generator Owners and Generator Operators and determined that no changes to specific requirements are necessary. The drafting team attempted to better explain its rationale in these cases in the latest version of the background document.
- **Several addressed commercial issues in their comments on the white paper.** Such comments are outside the scope of this drafting team (and NERC Reliability Standards in general) and thus have not been addressed here.
- **Some pointed out reference errors in the white paper.** The drafting team is grateful for these comments and has attempted to remedy all errors in the resource document that has evolved from the white paper.

The drafting team received no comments indicating that it should have included standards other than the two identified (FAC-001 and FAC-003), but several commenters suggested modifications to the proposed approaches to FAC-001 and FAC-003.

A number of comments stated that the “trigger” for the application of FAC-001 should not be the receipt of a request, but rather should be based upon “the intent or obligation” to interconnect a new Facility to an existing interconnecting Facility that is owned by a generator. Accordingly, the drafting team has proposed language to address this concern. The intent of this modified language is to start the compliance clock when the generator Facility owner executes an Agreement to perform the reliability assessment required in FAC-002. This step should occur whether the generator voluntarily agrees to the interconnection request or is compelled by a regulatory body to do so. In either case, we expect the Generator Owner and the requestor to execute some form of an Agreement. The drafting team intentionally excluded a specific reference to the kind of Agreement (such as a feasibility study) in deference to comments that we should avoid comingling of commercial and reliability aspects in reliability standards.

Similarly, a majority of comments supported FAC-003 applicability to the Generator Owner but suggested some exclusion for a “short length” Facility. Accordingly, we modified the language to apply only to a Facility that extends at least ½ mile beyond the fenced boundary(ies) of the switchyard, generating station, or generating substation.

In addition to the majority of comments addressing the line length issue, the drafting team received some minority comments on FAC-003:

- **Some indicated that Generator Owners should not be added to FAC-003 because they are never an IROL circuit.** FAC-003 addresses circuits other than those associated with an IROL.
- **Some stated that changing FAC-003 would do nothing to prevent adverse reliability impacts, because a radial line can't cascade.** The drafting team believes there is a reliability-related need to apply FAC-003 to GOs with extended interconnection Facilities.
- **One commenter suggested a better connection between FAC-003 and FAC-014, stating that there is nothing in either standard where the Planning Coordinator is informing the Transmission Owners and Generator Owners of the applicability of their Facilities as outlined in the Facilities section 4.2.2 of FAC-003.** FAC-014-2 R5 addresses this issue.
- **One commenter suggested that the requirement simply be that the Generator Owner coordinates with the Transmission Owner to ensure that the generator interconnection Facilities are included.** The drafting team believes there is a reliability-related need to apply FAC-003 to Generator Owners with extended interconnection Facilities. An entity always has the opportunity to enter into a JRO where appropriate.

A majority of commenters also supported the drafting team's proposal to not adopt new defined terms. But many commenters said that if the new terms were not adopted, the drafting team needed to work to address registration issues related to Generator Owners and Generator Operators, especially those with ownership/operational responsibility for the Facility that interconnects the generator(s) to the Transmission Owner's Facility. A few stated that there needed to be a clearer delineation of responsibilities between the Generator Owner and Transmission Owner and the Generator Operator and Transmission Operator where ownership and operational responsibility of an interconnection Facility wasn't clearly understood. While the drafting team agrees with some of the comments, it is not empowered to make all changes which may be necessary to alleviate the concerns expressed in the comments.

However, during this process, the drafting team has been meeting with NERC and FERC staffs, regional compliance managers, and industry organizations to discuss possible solutions to the issue of concern to most Generator Owner/Generator Operators (e.g., registration as a Transmission Owner/Transmission Operator). The drafting team believes this issue, and the related concerns, have the attention of appropriate NERC and regional staffs and has volunteered to provide assistance in their efforts to address them.

The goal of the Project 2010-07 drafting team is to work with NERC and regional compliance enforcement and compliance registration staffs to develop a comprehensive package that will address all reliability gaps, whether real or perceived, so that entities are appropriately registered and the appropriate reliability standards are applied to those entities.

**\*\*Note about comments from February and March 2010 SAR Posting\*\***

During its review of these comments, the drafting team also returned to comments from its SAR posting in February and March of 2010, as many of the comments on the SAR posting dealt with the proposals in the original Ad Hoc Group for Generator Requirements at the Transmission Interface's Final Report. In

returning to these comments, the drafting team confirmed that it had addressed all relevant comments. Because of the narrower focus of the current Project 2010-07, many comments (such as those on the Ad Hoc Group's proposed definitions) were no longer relevant, but all others have been addressed:

- **Need to align project with compliance responsibility:** The drafting team is working with NERC and regional compliance staffs on exactly this.
- **The scope of the project is too broad:** The scope has been narrowed.
- **The project needs further clarification:** The original white paper posted for informal comment was developed to provide further clarification on the project. That white paper has been modified to be used as a background resource document.
- **The standards changes should be implemented all at once:** With only two standard changes being implemented and an interim solution being developed by NERC's compliance staff (in coordination with Regional compliance staff), the drafting team is not as concerned with implementing the changes simultaneously. If, for instance, FAC-001 changes are implemented before FAC-003 changes, the interim compliance solution will remain in effect until FAC-003 changes are also implemented to ensure that there are no gaps during the implementation periods.

The drafting team thanks all those who participated in the original SAR posting; the comments from that posting were invaluable during the transition from ad hoc group to standard drafting team.



The drafting team limited its modifications to those associated with expanding the scope to include the Generator Owner and bringing the format up to date.

**A. Introduction**

- 1. Title:** Facility Connection Requirements
- 2. Number:** FAC-001-1
- 3. Purpose:** To avoid adverse impacts on reliability, Transmission Owners and Generator Owners must establish Facility connection and performance requirements.
- 4. Applicability:**
  - 4.1.** Transmission Owner
  - 4.2.** Applicable Generator Owner
    - 2.4.1.** Generator Owner with an executed Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility
- 5. Effective Date:**
  - 5.1.** In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner and Regional Entity become effective upon Board of Trustees' adoption.
  - 5.2.** In those jurisdictions where regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities. In those jurisdictions where no regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after Board of Trustees' adoption.

**B. Requirements**

- R1.** The Transmission Owner shall document, maintain, and publish Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, 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:
  - 1.1.** Generation Facilities,
  - 1.2.** Transmission Facilities, and
  - 1.3.** End-user Facilities

*[VRF – Medium]*
- R2.** Each applicable Generator Owner, within 45 days of executing an Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility (under FAC-002-1), shall document and publish and thereafter maintain Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, subregional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements.

*[VRF – Medium]*

**R3.** Each applicable Generator Owner with Facility connection requirements and each Transmission Owner shall have Facility connection requirements that address the following items:

**3.1.** Provide a written summary of its plans to achieve the required system performance as described in Requirements R1 and R2 throughout the planning horizon:

**3.1.1.** Procedures for coordinated joint studies of new Facilities and their impacts on the interconnected Transmission Systems.

**3.1.2.** Procedures for notification of new or modified Facilities to others (those responsible for the reliability of the interconnected Transmission Systems) as soon as feasible.

**3.1.3.** Voltage level and MW and MVAR capacity or demand at point of connection.

**3.1.4.** Breaker duty and surge protection.

**3.1.5.** System Protection and coordination.

**3.1.6.** Metering and telecommunications.

**3.1.7.** Grounding and safety issues.

**3.1.8.** Insulation and insulation coordination.

**3.1.9.** Voltage, Reactive Power, and power factor control.

**3.1.10.** Power quality impacts.

**3.1.11.** Equipment Ratings.

**3.1.12.** Synchronizing of Facilities.

**3.1.13.** Maintenance coordination.

**3.1.14.** Operational issues (abnormal frequency and voltages).

**3.1.15.** Inspection requirements for existing or new Facilities.

**3.1.16.** Communications and procedures during normal and emergency operating conditions.

*[VRF – Medium]*

**R4.** Each applicable Generator Owner with Facility connection requirements (in accordance with Requirement R2) and each Transmission Owner shall maintain Facility connection requirements and make documentation of these requirements available to the users of the Transmission System, the Regional Entity, and ERO on request (five business days).

*[VRF – Medium]*

## C. Measures

**M1.** The Transmission Owner shall make available (to its Compliance Enforcement Authority) evidence that it met all the requirements stated in Requirement R1.

- M2.** Each Generator Owner that executes an Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility shall make available (to its Compliance Enforcement Authority) evidence that it met all requirements stated in Requirement R2.
- M3.** Each applicable Generator Owner with Facility connection requirements and each Transmission Owner shall make available (to its Compliance Enforcement Authority) evidence that it met all requirements stated in Requirement R3.
- M4.** Each applicable Generator Owner with Facility connection requirements and each Transmission Owner shall make available (to its Compliance Enforcement Authority) evidence that it met all the requirements stated in Requirement R4.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

Compliance Monitor: Regional Entity

**1.2. Compliance Monitoring and Enforcement Processes:**

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

**1.3. Data Retention**

The Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Owner shall retain evidence of Requirement R1, Measure M1, Requirement R3, Measure M3, and Requirement R4, Measure M4 from its last audit.

The Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain evidence of Requirement R2, Measure M2, Requirement R3, Measure M3, and Requirement R4, Measure M4 from its last audit.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Additional Compliance Information**

None.

**2. Violation Severity Levels**

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Not Applicable.	<p>The Transmission Owner failed to do one of the following:</p> <p>Document or maintain or publish Facility connection requirements as specified in the Requirement</p> <p>OR</p> <p>Failed to include one (1) of the components and specified in R1.1, R1.2 or R1.3.</p>	<p>The Transmission Owner failed to do one of the following:</p> <p>Document or maintain or publish its Facility connection requirements as specified in the Requirement</p> <p>OR</p> <p>Failed to include (2) of the components as specified in R1.1, R1.2 or R1.3</p> <p>OR</p> <p>Failed to document or maintain or publish its Facility connection requirements as specified in the Requirement <b>and</b> failed to include one (1) of the components as specified in R1.1, R1.2 or R1.3.</p>	<p>The Transmission Owner did not develop Facility connection requirements.</p>
R2	The responsible entity failed to document and publish and thereafter maintain Facility connection requirements until more than 45 calendar days but less than or equal to 60 calendar days	The responsible entity failed to document and publish and thereafter maintain Facility connection requirements until more than 60 calendar days but less than or equal to 70 calendar days	The responsible entity failed to document and publish and thereafter maintain Facility connection requirements until more than 70 calendar days but less than or equal to 80 calendar days	The responsible entity failed to document and publish and thereafter maintain Facility connection requirements until more than 80 days after executing an Agreement to evaluate the

	after executing an Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility.	after executing an Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility.	after executing an Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility.	reliability impact of interconnecting another Facility to its existing generation Facility.
R3	The responsible entity's Facility connection requirements failed to address one of the subrequirements.	The responsible entity's Facility connection requirements failed to address two of the subrequirements.	The responsible entity's Facility connection requirements failed to address three of the sub-requirements.	The responsible entity's Facility connection requirements failed to address four or more of the subrequirements.  OR  The responsible entity does not have Facility connection requirements.
R4	The responsible entity made the requirements available more than five business days but less than or equal to 10 business days after a request.	The responsible entity made the requirements available more than 10 business days but less than or equal to 20 business days after a request.	The responsible entity made the requirements available more than 20 business days less than or equal to 30 business days after a request.	The responsible entity made the requirements available more than 30 business days after a request.

**E. Regional Differences**

1. None identified.

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	TBD	Added requirements for Generator Owner and brought overall standard format up to date	Revision under Project 2010-07



The drafting team limited its modifications to those associated with expanding the scope to include the Generator Owner and bringing the format up to date.

A. **Introduction**

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

2. **Number:** FAC-001-~~0-1~~

3. **Purpose:** To avoid adverse impacts on reliability, Transmission Owners and Generator Owners must establish Ffacility connection and performance requirements.

4. **Applicability:**

4.1. Transmission Owner

4.2. Applicable Generator Owner

4.1.2.4.1. Generator Owner with an executed Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility

5. **Effective Date:**

5.1. In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner and Regional Entity become effective upon Board of Trustees' adoption.

5.2. In those jurisdictions where regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities. In those jurisdictions where no regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after Board of Trustees' adoption.

~~5.~~ April 1, 2005

B. **Requirements**

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

1.1. Generation Ffacilities,

1.2. Transmission Ffacilities, and

~~R2.~~ End-user Ffacilities

1.3.

*[VRF – Medium]*

**R2.** Each applicable Generator Owner, within 45 days of executing an Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility (under FAC-002-1), shall document and publish and thereafter maintain Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, subregional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements.

~~R3.~~ [VRF – Medium]

**R3.** Each applicable Generator Owner with Facility connection requirements and each The Transmission Owner shall have Facility connection requirements that address the following items:

- 3.1.** Provide a written summary of its plans to achieve the required system performance as described ~~above in Requirements R1 and R2~~ throughout the planning horizon:
  - 3.1.1.** Procedures for coordinated joint studies of new ~~F~~facilities and their impacts on the interconnected ~~T~~transmission ~~S~~systems.
  - 3.1.2.** Procedures for notification of new or modified ~~F~~facilities to others (those responsible for the reliability of the interconnected ~~T~~transmission ~~S~~systems) as soon as feasible.
  - 3.1.3.** Voltage level and MW and MVAR capacity or demand at point of connection.
  - 3.1.4.** Breaker duty and surge protection.
  - 3.1.5.** System ~~p~~rotection and coordination.
  - 3.1.6.** Metering and telecommunications.
  - 3.1.7.** Grounding and safety issues.
  - 3.1.8.** Insulation and insulation coordination.
  - 3.1.9.** Voltage, Reactive Power, and power factor control.
  - 3.1.10.** Power quality impacts.
  - 3.1.11.** Equipment Ratings.
  - 3.1.12.** Synchronizing of ~~F~~facilities.
  - 3.1.13.** Maintenance coordination.
  - 3.1.14.** Operational issues (abnormal frequency and voltages).
  - 3.1.15.** Inspection requirements for existing or new ~~F~~facilities.
  - 3.1.16.** Communications and procedures during normal and emergency operating conditions.

[VRF – Medium]

**R4.** Each applicable Generator Owner with Facility connection requirements (in accordance with Requirement R2) and eachThe Transmission Owner shall maintain ~~and update its F~~facility connection requirements ~~as required and. The Transmission Owner shall~~ make documentation of these requirements available to the users of the ~~T~~transmission ~~S~~system, the Regional ~~Reliability Organization~~Entity, and ~~NERC-ERO~~ on request (five business days).

~~R4.~~ [VRF – Medium]



**C. Measures**

**M1.** The Transmission Owner shall make available (to its Compliance ~~Monitor~~Enforcement Authority) ~~for inspection~~ evidence that it met all the requirements stated in Reliability Standard FAC-001-0-Requirement R1.

**M2.** Each Generator Owner that executes an Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility shall make available (to its Compliance Enforcement Authority) evidence that it met all requirements stated in Requirement R2.

**M2.M3.** Each applicable Generator Owner with Facility connection requirements and eachThe Transmission Owner shall make available (to its Compliance ~~Monitor~~Enforcement Authority) ~~for inspection~~ evidence that it met all requirements stated in Reliability Standard FAC-001-0-Requirement R3.

**M3.M4.** Each applicable Generator Owner with Facility connection requirements and eachThe Transmission Owner shall make available (to its Compliance ~~Monitor~~Enforcement Authority) ~~for inspection~~ evidence that it met all the requirements stated in Reliability Standard FAC-001-0-Requirement R4.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority**

Compliance Monitor: Regional ~~Reliability Organization~~Entity

**1.2. ~~Compliance Monitoring Period and Reset Timeframe~~**  
~~On request (five business days).~~

**1.2. Data Retention Compliance Monitoring and Enforcement Processes:**

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

**1.3. Data Retention**

The Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Owner shall retain evidence of Requirement R1, Measure M1, Requirement R3, Measure M3, and Requirement R4, Measure M4 from its last audit.

The Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain evidence of Requirement R2, Measure M2, Requirement R3, Measure M3, and Requirement R4, Measure M4 from its last audit.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Additional Compliance Information**

None.

~~1.3. —~~

~~None specified.~~

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance Violation Severity Levels**

<u>R #</u>	<u>Lower VSL</u>	<u>Moderate VSL</u>	<u>High VSL</u>	<u>Severe VSL</u>
<u>R1</u>	<u>Not Applicable.</u>	<u>The Transmission Owner failed to do one of the following:</u>  <u>Document or maintain or publish Facility connection requirements as specified in the Requirement</u>  <u>OR</u>  <u>Failed to include one (1) of the components and specified in R1.1, R1.2 or R1.3.</u>	<u>The Transmission Owner failed to do one of the following:</u>  <u>Document or maintain or publish its Facility connection requirements as specified in the Requirement</u>  <u>OR</u>  <u>Failed to include (2) of the components as specified in R1.1, R1.2 or R1.3</u>  <u>OR</u>  <u>Failed to document or maintain or publish its Facility connection requirements as specified in the Requirement <b>and</b> failed to include</u>	<u>The Transmission Owner did not develop Facility connection requirements.</u>

			<u>one (1) of the components as specified in R1.1, R1.2 or R1.3.</u>	
<u>R2</u>	<u>The responsible entity failed to document and publish and thereafter maintain Facility connection requirements until more than 45 calendar days but less than or equal to 60 calendar days after executing an Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility.</u>	<u>The responsible entity failed to document and publish and thereafter maintain Facility connection requirements until more than 60 calendar days but less than or equal to 70 calendar days after executing an Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility.</u>	<u>The responsible entity failed to document and publish and thereafter maintain Facility connection requirements until more than 70 calendar days but less than or equal to 80 calendar days after executing an Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility.</u>	<u>The responsible entity failed to document and publish and thereafter maintain Facility connection requirements until more than 80 days after executing an Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility.</u>
<u>R3</u>	<u>The responsible entity's Facility connection requirements failed to address one of the subrequirements.</u>	<u>The responsible entity's Facility connection requirements failed to address two of the subrequirements.</u>	<u>The responsible entity's Facility connection requirements failed to address three of the sub-requirements.</u>	<u>The responsible entity's Facility connection requirements failed to address four or more of the subrequirements.</u>  <u>OR</u>  <u>The responsible entity does not have Facility connection requirements.</u>
<u>R4</u>	<u>The responsible entity made the requirements available more than five business days but less than or equal to 10 business days after a request.</u>	<u>The responsible entity made the requirements available more than 10 business days but less than or equal to 20 business days after a request.</u>	<u>The responsible entity made the requirements available more than 20 business days less than or equal to 30 business days after a request.</u>	<u>The responsible entity made the requirements available more than 30 business days after a request.</u>

- ~~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
0	April 1, 2005	Effective Date	New
<u>1</u>	<u>TBD</u>	<u>Added requirements for Generator Owner and brought overall standard format up to date</u>	<u>Revision under Project 2010-07</u>

## **Implementation Plan for FAC-001-1 – Facility Connection Requirements**

### **Prerequisite Approvals**

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

### **Revision to Sections of Approved Standards and Definitions**

There are no proposed revisions to requirements in other already approved standards. FAC-001-0 will be retired when FAC-001-1 becomes effective.

### **Compliance with Standard**

Since this version of the standard imposes no changes to Transmission Owners from those in the FERC-approved version of the standard, the expectation is that Transmission Owners will maintain their current state of compliance. Thus, the standard is effective for Transmission Owners upon approval, as detailed below.

The proposed changes to the FERC-approved version of this standard only address Generator Owner applicability and requirements (add Generator Owner to section 4.2, introduce a new requirement (R2), and modify two existing requirements (now R3 and R4)). Therefore, this implementation plan only identifies a compliance timeframe for Generator Owners to which this standard will apply.

### **Effective Date**

There are two effective dates associated with this standard:

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner and Regional Entity become effective upon Board of Trustees' adoption.

In those jurisdictions where regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities. In those jurisdictions where no regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after Board of Trustees' adoption.

**Standard Development Timeline**

*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**

1. SC approved SAR for initial posting (January 11, 2007).
2. SAR posted for comment (January 15–February 14, 2007).
3. SAR posted for comment (April 10–May 9, 2007).
4. SC authorized moving the SAR forward to standard development (June 27, 2007).
5. First draft of proposed standard posted (October 27, 2008-November 25, 2008)).
6. Second draft of revised standard posted (September 10, 20–October 24, 2009).
7. Third draft of revised standard posted (March 1, 2010-March 31, 2010).
8. Forth draft of revised standard posted (June 17, 2010-July 17, 2010).

**Proposed Action Plan and Description of Current Draft**

This is the third posting of the proposed revisions to the standard in accordance with Results-Based Criteria and the fifth draft overall.

**Future Development Plan**

<b>Anticipated Actions</b>	<b>Anticipated Date</b>
Recirculation ballot of standards.	January 2011
Receive BOT approval	February 2011

### Effective Dates

There are three effective dates associated with this implementation plan:

The first effective date applies to Transmission Owners.

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner become effective upon Board of Trustees' adoption.

The second effective date allows Generator Owners time to develop documented maintenance strategies or procedures or processes or specifications as outlined in Requirement R3.

In those jurisdictions where regulatory approval is required, Requirement R3 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The third effective date allows entities time to comply with Requirements R1, R2, R4, R5, R6, and R7.

In those jurisdictions where regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for is required. In those jurisdictions where no regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

### Exceptions:

A line operated below 200kV, designated by the Planning Coordinator as an element of an IROL or as a Major WECC transfer path, becomes subject to this standard 12 months after the date the Planning Coordinator or WECC initially designates the line as being subject to this standard.

An existing transmission line operated at 200kV or higher that is newly acquired by an asset owner and was not previously subject to this standard, becomes subject to this standard 12 months after the acquisition date of the line.

Version History

<b>Version</b>	<b>Date</b>	<b>Action</b>	<b>Change Tracking</b>
1	TBA	<ol style="list-style-type: none"> <li>1. Added “Standard Development Roadmap.”</li> <li>2. Changed “60” to “Sixty” in section A, 5.2.</li> <li>3. Added “Proposed Effective Date: April 7, 2006” to footer.</li> <li>4. Added “Draft 3: November 17, 2005” to footer.</li> </ol>	01/20/06
1	April 4, 2007	Regulatory Approval — Effective Date	New
3	May 16, 2011	Modified proposed definitions and Applicability to include Generator Owners of a certain length.	Revision under Project 2010-07



## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary. When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.*

### **Right-of-Way (ROW)**

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria.

The current glossary definition of this NERC term is modified to address the issues set forth in Paragraph 734 of FERC Order 693.

### **Vegetation Inspection**

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the applicable Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.

Current definition of Vegetation Inspection:  
The systematic examination of a transmission corridor to document vegetation conditions.

FAC-003-2 is currently under development under Project 2007-07. The project is nearing its final stages, but the Project 2010-07 drafting team does not want to assume that the project will be approved by NERC's Board or Trustees (BOT) or FERC. Thus, the Project 2010-07 drafting team has developed two sets of proposed changes: one to this version, the latest draft of Version 2 as proposed by the Project 2007-07 team, and one to FAC-003-1, the current FERC-approved version of the standard.

If FAC-003-2 is approved by NERC's BOT, the Project 2010-07 drafting team will likely proceed with the modifications seen in this standard. These changes would be submitted for stakeholder approval and balloted as FAC-003-3. FAC-003-2 would be retired once FAC-003-03 was approved.

If, however, FAC-003-2 remains under development, the Project 2010-07 drafting team will proceed with changes to FAC-003-1 to avoid further delay of its project goals. Changes to FAC-003-1 would address the addition of Generator Owners to the applicability, the proposal of modifications to the NERC defined term Right-of-Way to include applicable Generator Owners, and some formatting changes to bring the standard up to date. These changes would not be comprehensive; rather, they would aim to include the generator interconnection Facility in the standard with as few other changes as possible.

## Introduction

- 1. Title:** Transmission Vegetation Management
- 2. Number:** FAC-003-3
- 3. Objectives:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.
- 4. Applicability**
  - 4.1. Functional Entities:**
    - 4.1.1. Applicable Transmission Owners**
      - 4.1.1.1.** Transmission Owners that own Transmission Facilities defined in 4.2
    - 4.1.2. Applicable Generator Owners**
      - 4.1.2.1.** Generator Owners that own Generation Facilities defined in 4.3

**4.2. Transmission Facilities:** Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal<sup>1</sup>, state, provincial, public, private, or tribal entities:

**4.2.1.** Overhead transmission lines operated at 200kV or higher.

**4.2.2.** Overhead transmission lines operated below 200kV having been identified as included in the definition of an Interconnection Reliability Operating Limit (IROL) under NERC Standard FAC-014 by the Planning Coordinator.

**4.2.3.** Overhead transmission lines operated below 200 kV having been identified as included in the definition of one of the *Major WECC Transfer Paths in the Bulk Electric System*.

**4.2.4.** This standard applies to overhead transmission lines identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

**Rationale**

The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) Specifically addressing the areas where the standard applies or doesn't makes the standard stronger as it relates to clarity.

**4.3. Generation Facilities:** Defined below (referred to as “applicable lines”):

**4.3.1.** Overhead transmission lines that extend greater than one half mile beyond the fenced area of the switchyard, generating station or generating substation up to the point of interconnection with the Transmission system and are:

**4.3.1.1.** Operated at 200kV or higher; or

**4.3.1.2.** Operated below 200kV having been identified as included in the definition of an Interconnection Reliability Operating Limit (IROL) under NERC Standard FAC-014 by the Planning Coordinator; or

Within the text of NERC Reliability Standard FAC-003-3, “transmission line(s)” and “applicable line(s)” can also refer to the generation Facilities as referenced in 4.3 and its subsections.

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<sup>1</sup> EPAAct 2005 section 1211c: “Access approvals by Federal agencies”.

**4.3.1.3.** Operated below 200kV having been identified as included in the definition of one of the *Major WECC Transfer Paths in the Bulk Electric System*.

**4.4. Enforcement:** *The reliability obligations of the applicable entities and facilities are contained within the technical requirements of this standard. [Straw proposal]*

## **5. Background:**

This NERC Vegetation Management Standard (“Standard”) uses a defense-in-depth approach to improve the reliability of the electric Transmission System by preventing those vegetation related outages that could lead to Cascading. This Standard is not intended to address non-preventable outages such as those due to vegetation fall-ins or blow-ins from outside the Right-of-Way, vandalism, human activities and acts of nature. Operating experience indicates that trees that have grown out of specification have contributed to Cascading, especially under heavy electrical loading conditions.

With a defense-in-depth strategy, this Standard utilizes three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

- a) Performance-based — defines a particular reliability objective or outcome to be achieved.
- b) Risk-based — preventive requirements to reduce the risks of failure to acceptable tolerance levels.
- c) Competency-based — defines a minimum capability an entity needs to have to demonstrate it is able to perform its designated reliability functions.

The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard. For this Standard, the requirements have been developed as follows:

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

Thus the various requirements associated with a successful vegetation program could be viewed as using R1, R2 and R3 as first levels of defense; while R4 could be a subsequent or final level of defense. R6 depending on the particular vegetation approach may be either an initial defense barrier or a final defense barrier.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the Standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the Standard the term “public lands” includes municipal lands, village lands, city lands, and a host of other governmental entities.

This Standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This Standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this Standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of multiple line failures and Cascading. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are statistically intermittent. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this Standard’s emphasis is on vegetation grow-ins.

Requirements and Measures

**R1.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments of the types shown below, into the Minimum Vegetation Clearance Distance (MVCD) of any of its applicable line(s) identified as an element of an Interconnection Reliability Operating Limit (IROL) in the planning horizon by the Planning Coordinator; or Major Western Electricity Coordinating Council (WECC) transfer path(s); operating within its Rating and all Rated Electrical Operating Conditions.<sup>2</sup>

1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,
2. An encroachment due to a fall-in from inside the Right-of-Way (ROW) that caused a vegetation-related Sustained Outage,
3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,
4. An encroachment due to a grow-in that caused a vegetation-related Sustained Outage. *[VRF – High] [Time Horizon – Real-time]*

**M1.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments.

If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

**Rationale**

The MVCD is a calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages. The distances in Table 2 were derived using a proven transmission design method. The types of failure to manage vegetation are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable Transmission Owner’s or applicable Generator Owner’s vegetation maintenance program since the encroachments listed require different and increasing levels of skills and knowledge and thus constitute a logical progression of how well, or poorly, an applicable Transmission Owner or applicable Generator Owner manages vegetation relative to this Requirement.

<sup>2</sup> This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation. Nothing in this footnote should be construed to limit the applicable Transmission Owner’s or applicable Generator Owner’s right to exercise its full legal rights on the ROW.

Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period. (R1)

- R2.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments of the types shown below, into the MVCD of any of its applicable line(s) that is not an element of an IROL; or Major WECC transfer path; operating within its Rating and all Rated Electrical Operating Conditions.<sup>2</sup>
1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,
  2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,
  3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,
  4. An encroachment due to a grow-in that caused a vegetation-related Sustained Outage.  
*[VRF – Medium] [Time Horizon – Real-time]*

**Rationale**

The MVCD is a calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages. The distances in Table 2 were derived using a proven transmission design method. The types of failure to manage vegetation are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable Transmission Owner’s or applicable Generator Owner’s vegetation maintenance program since the encroachments listed require different and increasing levels of skills and knowledge and thus constitute a logical progression of how well, or poorly, an applicable Transmission Owner or applicable Generator Owner manages vegetation relative to this Requirement.

- M2.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments.

If a later confirmation of a Fault by the applicable Transmission Owner and applicable Generator Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period. (R2)

**R3.** Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable transmission lines that include(s) the following:

- 3.1** Accounts for the movement of applicable transmission line conductors under their Facility Rating and all Rated Electrical Operating Conditions;
- 3.2** Accounts for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

**Rationale**

The documentation provides a basis for evaluating the competency of the applicable Transmission Owner’s or applicable Generator Owner’s ’s vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Rated Electrical Operating Conditions. See Figure 1 for an illustration of possible conductor locations.

*[VRF – Lower] [Time Horizon – Long Term Planning]*

**M3.** The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

**R4.** Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable transmission line when the applicable Transmission Owner or applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment.

**Rationale**

To ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

*[VRF – Medium] [Time Horizon – Real-time]*

**M4.** Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)



**R5.** When a applicable Transmission Owner or applicable Generator Owner is constrained from performing vegetation work, and the constraint may lead to a vegetation encroachment into the MVCD of its applicable transmission lines prior to the implementation of the next annual work plan then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments.

*[VRF – Medium] [Time Horizon – Operations Planning]*

**Rationale**

Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work. In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner or applicable Generator Owner to put interim measures in place, rather than do nothing. The corrective action process is intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

**M5.** Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, and evidence that a line was de-energized. (R5)

**R6.** Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 months between inspections on the same ROW.<sup>3</sup>

*[VRF – Medium] [Time Horizon – Operations Planning]*

**M6.** Each applicable Transmission Owner and applicable Generator

**Rationale**

Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Applicable Transmission Owners and applicable Generator Owners should consider local and environmental factors that could warrant more frequent inspections.

<sup>3</sup> When the applicable Transmission Owner or applicable Generator Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the applicable Transmission Owner or applicable Generator Owner is granted a time extension that is equivalent to the duration of the time the applicable Transmission Owner or applicable Generator Owner was prevented from performing the Vegetation Inspection.

Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable transmission lines at least once per calendar year but with no more than 18 months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

**R7.** Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not put the transmission system at risk of a vegetation encroachment) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include:

**Rationale**

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. An annual vegetation work plan allows for work to be modified for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that the changes do not violate the encroachment within the MVCD.

- Change in expected growth rate/ environmental factors
- Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner <sup>4</sup>
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Emerging technologies

*[VRF – Medium] [Time Horizon – Operations Planning]*

**M7.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (including modifications if any), dated work orders, dated invoices, or dated inspection records. (R7)

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<sup>4</sup> Circumstances that are beyond the control of a applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; arboricultural, horticultural or agricultural activities.

## Compliance

### **Compliance Enforcement Authority**

- Regional Entity

### **Compliance Monitoring and Enforcement Processes:**

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints
- Periodic Data Submittals

### **Evidence Retention**

The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, Measures M1, M2, M3, M5, M6 and M7 for three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

### **Additional Compliance Information**

***Periodic Data Submittal:*** The applicable Transmission Owner and applicable Generator Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable transmission lines determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation, except as excluded in footnote 2, which includes as a minimum, the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner .

A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable transmission lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable transmission lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable transmission lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable transmission lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable transmission lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable transmission lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable transmission lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

Time Horizons, Violation Risk Factors, and Violation Severity Levels

Table 1						
R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Real-time	High	The responsible entity had an encroachment into the MVCD observed in Real-time, absent a Sustained Outage.	The responsible entity had an encroachment into the MVCD due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage.	The responsible entity had an encroachment into the MVCD due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage.	The responsible entity had an encroachment into the MVCD due to a grow-in that caused a vegetation-related Sustained Outage.
R2	Real-time	Medium	The responsible entity had an encroachment into the MVCD observed in Real-time, absent a Sustained Outage.	The responsible entity had an encroachment into the MVCD due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage.	The responsible entity had an encroachment into the MVCD due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage.	The responsible entity had an encroachment into the MVCD due to a grow-in that caused a vegetation-related Sustained Outage.
R3	Long-Term Planning	Lower		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates,	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of

				vegetation control methods, and inspection frequency, for the responsible entity's applicable lines.	movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines.	vegetation into the MVCD, for the responsible entity's applicable lines.
R4	Real-time	Medium			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that transmission line, but there was intentional delay in that notification.	The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that transmission line.
R5	Operations Planning	Medium				The responsible entity did not take corrective action when it was constrained from performing planned vegetation work where a transmission line was put at potential risk.
R6	Operations Planning	Medium	The responsible entity failed to inspect 5% or less of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 15% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).

			kilometers, etc.)			
R7	Operations Planning	Medium	The responsible entity failed to complete up to 5% of its annual vegetation work plan (including modifications if any).	The responsible entity failed to complete more than 5% and up to 10% of its annual vegetation work plan (including modifications if any).	The responsible entity failed to complete more than 10% and up to 15% of its annual vegetation work plan (including modifications if any).	The responsible entity failed to complete more than 15% of its annual vegetation work plan (including modifications if any).

**Variances**

None.

**Interpretations**

None.



## Guideline and Technical Basis

### **Requirements R1 and R2:**

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the prevention of vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each applicable Transmission Owner and applicable Generator Owner to manage vegetation to prevent encroachment within the Minimum Vegetation Clearance Distance (“MVCD”) of transmission lines. R1 is applicable to lines “identified as an element of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path (operating within Rating and Rated Electrical Operating Conditions) to avoid a Sustained Outage”. R2 applies to all other applicable lines that are not an element of an IROL or Major WECC Transfer Path.

The separation of applicability (between R1 and R2) recognizes that an encroachment into the MVCD of an IROL or Major WECC Transfer Path transmission line is a greater risk to the electric transmission system. Applicable lines that are not an element of an IROL or Major WECC Transfer Path are required to be clear of vegetation but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

These requirements (R1 and R2) state that if vegetation encroaches within the distances in Table 1 in Appendix 1 of this supplemental Transmission Vegetation Management Standard FAC-003-2 Technical Reference document, it is in violation of the standard. Table 2 tabulates the distances necessary to prevent spark-over based on the Gallet equations as described more fully in Appendix 1 below.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating (potentially in violation of other standards), the occurrence of a clearance encroachment may occur. For example, emergency actions taken by a Transmission Operator or Reliability Coordinator to protect an Interconnection may cause the transmission line to sag more and come closer to vegetation, potentially causing an outage. Such vegetation-related outages are not a violation of these requirements.

Evidence of violation of Requirement R1 and R2 include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to blowing together of applicable lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. If an investigation of a Fault by an applicable Transmission Owner or applicable Generator Owner confirms that a vegetation encroachment within the MVCD occurred, then it shall be considered the equivalent of a Real-time observation.

With this approach, the VSLs were defined such that they directly correlate to the severity of a failure of an applicable Transmission Owner and applicable Generator Owner to manage vegetation and to the corresponding performance level of the applicable Transmission Owner’s or applicable Generator Owner’s vegetation program’s ability to meet the goal of “preventing a Sustained Outage that could lead to Cascading.” Thus violation severity increases with an

applicable Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example, a limb may only partially break and intermittently contact a conductor. Such events are considered to be a single vegetation-related Sustained Outage under the Standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Facilities. Keeping vegetation from entering this space will prevent transmission outages.

### **Requirement R3:**

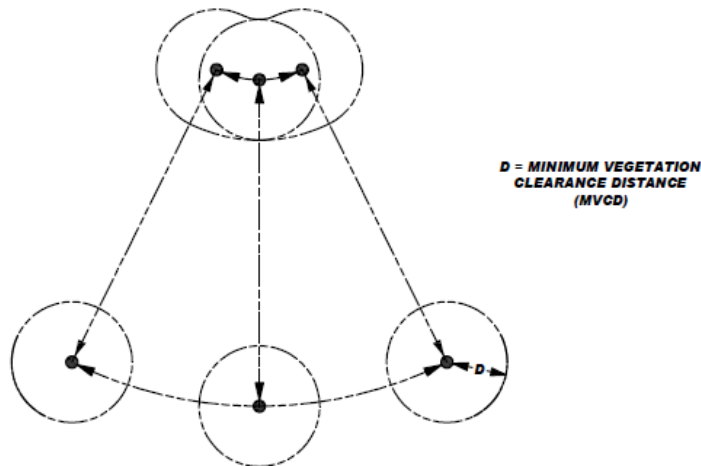
Requirement R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable Transmission Owner or applicable Generator Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the Transmission System. The approach provides the basis for evaluating the intent, allocation of appropriate resources and the competency of the applicable Transmission Owner or applicable Generator Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner must be able to state what its approach is and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an applicable Transmission Owner or applicable Generator Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing as a reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below.



**Figure 1**

Cross-section view of a single conductor at a given point along the span showing six possible conductor positions due to movement resulting from thermal and mechanical loading.

**Requirement R4:**

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner’s or applicable Generator Owner’s employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or positioning the system in recognition of the increasing risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

**Requirement R5:**

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the applicable Transmission Owner or applicable Generator Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for each location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner could consider location specific measures such as modifying the inspection and/or maintenance

intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.

- The applicable Transmission Owner or applicable Generator Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

**Requirement R6:**

R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections that fits general industry practice. In addition, the fact that Vegetation Inspections can be performed in conjunction with general line inspections further facilitates an applicable Transmission Owner's or applicable Generator Owner's ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner may determine that more frequent inspections are needed to maintain reliability levels, dependent upon such factors as anticipated growth rates of the local vegetation, length of the growing season for the geographical area, limited ROW width, and rainfall amounts. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSL for Requirement R6 has VSL categories ranked by the percentage of the required ROW inspections completed. To calculate the percentage of inspection completion, the applicable Transmission Owner or applicable Generator Owner may choose units such as: line miles or kilometers, circuit miles or kilometers, pole line miles, ROW miles, etc.

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of 230 kV transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all 2,000 miles of 230 kV transmission lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be  $100/2000 = 0.05$  or 5%. The "Low VSL" for R6 would apply in this example.

**Requirement R7:**

R7 is a risk-based requirement. The applicable Transmission Owner or applicable Generator Owner is required to implement an annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a "span-by-span", or even a "line-by-line" detailed description of all work to be performed. It is only intended to require that the applicable Transmission Owner or applicable Generator Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned

maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner's or applicable Generator Owner's system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan. Modifications to the annual work plan must always ensure the reliability of the electric Transmission system.

In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner's or applicable Generator Owner's easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management in the long term because it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)<sup>5</sup>  
For Alternating Current Voltages

( AC ) Nominal System Voltage (kV)	( AC ) Maximum System Voltage (kV)	MVCD feet (meters) sea level	MVCD feet (meters) 3,000ft (914.4m)	MVCD feet (meters) 4,000ft (1219.2m)	MVCD feet (meters) 5,000ft (1524m)	MVCD feet (meters) 6,000ft (1828.8m)	MVCD feet (meters) 7,000ft (2133.6m)	MVCD feet (meters) 8,000ft (2438.4m)	MVCD feet (meters) 9,000ft (2743.2m)	MVCD feet (meters) 10,000ft (3048m)	MVCD feet (meters) 11,000ft (3352.8m)
765	800	8.06ft (2.46m)	8.89ft (2.71m)	9.17ft (2.80m)	9.45ft (2.88m)	9.73ft (2.97m)	10.01ft (3.05m)	10.29ft (3.14m)	10.57ft (3.22m)	10.85ft (3.31m)	11.13ft (3.39m)
500	550	5.06ft (1.54m)	5.66ft (1.73m)	5.86ft (1.79m)	6.07ft (1.85m)	6.28ft (1.91m)	6.49ft (1.98m)	6.7ft (2.04m)	6.92ft (2.11m)	7.13ft (2.17m)	7.35ft (2.24m)
345	362	3.12ft (0.95m)	3.53ft (1.08m)	3.67ft (1.12m)	3.82ft (1.16m)	3.97ft (1.21m)	4.12ft (1.26m)	4.27ft (1.30m)	4.43ft (1.35m)	4.58ft (1.40m)	4.74ft (1.44m)
230	242	2.97ft (0.91m)	3.36ft (1.02m)	3.49ft (1.06m)	3.63ft (1.11m)	3.78ft (1.15m)	3.92ft (1.19m)	4.07ft (1.24m)	4.22ft (1.29m)	4.37ft (1.33m)	4.53ft (1.38m)
161*	169	2ft (0.61m)	2.28ft (0.69m)	2.38ft (0.73m)	2.48ft (0.76m)	2.58ft (0.79m)	2.69ft (0.82m)	2.8ft (0.85m)	2.91ft (0.89m)	3.03ft (0.92m)	3.14ft (0.96m)
138*	145	1.7ft (0.52m)	1.94ft (0.59m)	2.03ft (0.62m)	2.12ft (0.65m)	2.21ft (0.67m)	2.3ft (0.70m)	2.4ft (0.73m)	2.49ft (0.76m)	2.59ft (0.79m)	2.7ft (0.82m)
115*	121	1.41ft (0.43m)	1.61ft (0.49m)	1.68ft (0.51m)	1.75ft (0.53m)	1.83ft (0.56m)	1.91ft (0.58m)	1.99ft (0.61m)	2.07ft (0.63m)	2.16ft (0.66m)	2.25ft (0.69m)
88*	100	1.15ft (0.35m)	1.32ft (0.40m)	1.38ft (0.42m)	1.44ft (0.44m)	1.5ft (0.46m)	1.57ft (0.48m)	1.64ft (0.50m)	1.71ft (0.52m)	1.78ft (0.54m)	1.86ft (0.57m)
69*	72	0.82ft (0.25m)	0.94ft (0.29m)	0.99ft (0.30m)	1.03ft (0.31m)	1.08ft (0.33m)	1.13ft (0.34m)	1.18ft (0.36m)	1.23ft (0.37m)	1.28ft (0.39m)	1.34ft (0.41m)

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above).

<sup>5</sup> The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

**Table 2 (cont.) — Minimum Vegetation Clearance Distances (MVCD)  
For Direct Current Voltages**

( DC ) Nominal Pole to Ground Voltage (kV)	MVCD feet (meters) sea level	MVCD feet (meters) 3,000ft (914.4m) Alt.	MVCD feet (meters) 4,000ft (1219.2m) Alt.	MVCD feet (meters) 5,000ft (1524m) Alt.	MVCD feet (meters) 6,000ft (1828.8m) Alt.	MVCD feet (meters) 7,000ft (2133.6m) Alt.	MVCD feet (meters) 8,000ft (2438.4m) Alt.	MVCD feet (meters) 9,000ft (2743.2m) Alt.	MVCD feet (meters) 10,000ft (3048m) Alt.	MVCD feet (meters) 11,000ft (3352.8m) Alt.
±750	13.92ft (4.24m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.9ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.07ft (3.07m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	(13.54ft 4.13m)
±500	7.89ft (2.40m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	4.78ft (1.46m)	5.35ft (1.63m)	5.55ft (1.69m)	5.75ft (1.75m)	5.95ft (1.81m)	6.15ft (1.87m)	6.36ft (1.94m)	6.57ft (2.00m)	6.77ft (2.06m)	6.98ft (2.13m)
±250	3.43ft (1.05m)	4.02ft (1.23m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5ft (1.52m)	5.17ft (1.58m)

Notes:

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet Equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:



- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 uses the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-01 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 5 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 7 would have to be used. Table 7 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines, as such, are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line is approximately 2.0 per unit. This value is a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 242 kV and below is considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at 362 kV and above a transient over-voltage factor of 1.4 per unit is considered a realistic maximum.

The Gallet Equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet Equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America [1].

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

While EPRI is currently trying to establish empirical data for spark-over distances to live vegetation, there are no spark-over formulas currently derived expressly for vegetation to conductor minimum distances. Therefore the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations using various transient overvoltage values.

**Comparison of spark-over distances computed using Gallet wet equations  
vs.  
IEEE 516-2003 MAID distances  
using various transient over-voltage factors**

<b>( AC ) Nom System Voltage (kV)</b>	<b>( AC ) Max System Voltage (kV)</b>	<b>Transient Over-voltage Factor (T)</b>	<b>Clearance (ft.) Gallet (wet) @ Alt. 3000 feet</b>	<b>Table 5 IEEE 516 MAID (ft) @ Alt. 3000 feet</b>
765	800	1.4	8.89	8.65
500	550	1.4	5.65	4.92
345	362	1.4	3.52	3.13
230	242	2.0	3.35	2.8
115	121	2.0	1.6	1.4

<b>( AC ) Nom System Voltage (kV)</b>	<b>( AC ) Max System Voltage (kV)</b>	<b>Transient Over-voltage Factor (T)</b>	<b>Clearance (ft.) Gallet (wet) @ Alt. 3000 feet</b>	<b>Table 5 (historical maximums) IEEE 516 MAID (ft) @ Alt. 3000 feet</b>
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

<b>( AC ) Nom System Voltage (kV)</b>	<b>( AC ) Max System Voltage (kV)</b>	<b>Transient Over-voltage Factor (T)</b>	<b>Clearance (ft.) Gallet (wet) @ Alt. 3000 feet</b>	<b>Table 7 IEEE 516 MAID (ft) @ Alt. 3000 feet</b>
765	800	2.5	20.25	20.4
500	550	3.0	15.02	14.7
345	362	3.5	10.42	9.44
230	242	3.5	6.32	5.14
115	121	3.5	2.90	2.45

### Standard Development Timeline

*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

1. SC approved SAR for initial posting (January 11, 2007).
2. SAR posted for comment (January 15–February 14, 2007).
3. SAR posted for comment (April 10–May 9, 2007).
4. SC authorized moving the SAR forward to standard development (June 27, 2007).
5. First draft of proposed standard posted (October 27, 2008–November 25, 2008)).
6. Second draft of revised standard posted (September 10, 20–October 24, 2009).
7. Third draft of revised standard posted (March 1, 2010–March 31, 2010).
8. Forth draft of revised standard posted (June 17, 2010–July 17, 2010).

### Proposed Action Plan and Description of Current Draft

This is the third posting of the proposed revisions to the standard in accordance with Results-Based Criteria and the fifth draft overall.

### Future Development Plan

Anticipated Actions	Anticipated Date
Recirculation ballot of standards.	January 2011
Receive BOT approval	February 2011

## Effective Dates

There are three effective dates associated with this implementation plan:

The first effective date applies to Transmission Owners.

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner become effective upon Board of Trustees' adoption.

The second effective date allows Generator Owners time to develop documented maintenance strategies or procedures or processes or specifications as outlined in Requirement R3.

In those jurisdictions where regulatory approval is required, Requirement R3 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The third effective date allows entities time to comply with Requirements R1, R2, R4, R5, R6, and R7.

In those jurisdictions where regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for is required. In those jurisdictions where no regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

~~First calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval is required.~~

## Exceptions:

A line operated below 200kV, designated by the Planning Coordinator as an element of an IROL or as a Major WECC transfer path, becomes subject to this standard 12 months after the date the Planning Coordinator or WECC initially designates the line as being subject to this standard.

An existing transmission line operated at 200kV or higher that is newly acquired by an asset owner and was not previously subject to this standard, becomes subject to this standard 12 months after the acquisition date of the line.

Version History

Version	Date	Action	Change Tracking
1	TBA	<ol style="list-style-type: none"> <li>1. Added “Standard Development Roadmap.”</li> <li>2. Changed “60” to “Sixty” in section A, 5.2.</li> <li>3. Added “Proposed Effective Date: April 7, 2006” to footer.</li> <li>4. Added “Draft 3: November 17, 2005” to footer.</li> </ol>	01/20/06
1	April 4, 2007	Regulatory Approval — Effective Date	New
<del>23</del>	<u>May 16, 2011</u>	<u>Modified proposed definitions and Applicability to include Generator Owners of a certain length.</u>	<u>Revision under Project 2010-07</u>

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary. When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.*

### **Right-of-Way (ROW)**

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria.

The current glossary definition of this NERC term is modified to address the issues set forth in Paragraph 734 of FERC Order 693.

### **Vegetation Inspection**

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the applicable Transmission Owner's or applicable Generator Owner's ~~Transmission Owner's~~ control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.

Current definition of Vegetation Inspection:  
The systematic examination of a transmission corridor to document vegetation conditions.



FAC-003-2 is currently under development under Project 2007-07. The project is nearing its final stages, but the Project 2010-07 drafting team does not want to assume that the project will be approved by NERC's Board or Trustees (BOT) or FERC. Thus, the Project 2010-07 drafting team has develop two sets of proposed changes: one to this version, the latest draft of Version 2 as proposed by the Project 2007-07 team, and one to FAC-003-1, the current FERC-approved version of the standard.

If FAC-003-2 is approved by NERC's BOT, the Project 2010-07 drafting team will likely proceed with the modifications seen in this standard. These changes would be submitted for stakeholder approval and balloted as FAC-003-3. FAC-003-2 would be retired once FAC-003-03 was approved.

If, however, FAC-003-2 remains under development, the Project 2010-07 drafting team will proceed with changes to FAC-003-1 to avoid further delay of its project goals. Changes to FAC-003-1 would address the addition of Generator Owners to the applicability, the proposal of modifications to the NERC defined term Right-of-Way to include applicable Generator Owners, and some formatting changes to bring the standard up to date. These changes would not be comprehensive; rather, they would aim to include the generator interconnection Facility in the standard with as few other changes as possible.

## Introduction

1. **Title:** Transmission Vegetation Management
2. **Number:** FAC-003-~~32~~
3. **Objectives:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

## 4. Applicability

### 4.1. Functional Entities:

#### 4.1.1. Applicable Transmission Owners

##### 4.1.1.1. Transmission Owners that own Transmission Facilities defined in 4.2

#### 4.1.2. Applicable Generator Owners

##### 4.1.2.1. Generator Owners that own Generation Facilities defined in 4.3

### ~~4.1. Functional Entities:~~

#### ~~Transmission Owners~~

**4.2. Transmission Facilities:** Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal<sup>1</sup>, state, provincial, public, private, or tribal entities:

**4.2.1.** Overhead transmission lines operated at 200kV or higher.

**4.2.2.** Overhead transmission lines operated below 200kV having been identified as included in the definition of an Interconnection Reliability Operating Limit (IROL) under NERC Standard FAC-014 by the Planning Coordinator.

**4.2.3.** Overhead transmission lines operated below 200 kV having been identified as included in the definition of one of the *Major WECC Transfer Paths in the Bulk Electric System*.

**4.2.4.** This standard applies to overhead transmission lines identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

### Rationale

—The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) ~~The standard was written for Transmission Owners. Rolling the excluded areas into this standard will bring GO and DP into the standard, even though NERC has an initiative in place to address this bigger registry issue.~~ 4) Specifically addressing the areas where the standard applies or doesn't makes the standard stronger as it relates to clarity.

**4.3. Generation Facilities:** Defined below (referred to as “applicable lines”):

**4.3.1. Overhead transmission lines that extend greater than one half mile beyond the fenced area of the switchyard, generating station or generating substation up to the point of interconnection with the Transmission system and are:**

**4.3.1.1. Operated at 200kV or higher; or**

**4.3.1.2. Operated below 200kV having been identified as included in the definition of an Interconnection Reliability Operating Limit (IROL) under NERC Standard FAC-014 by the Planning Coordinator; or**

Within the text of NERC Reliability Standard FAC-003-3, “transmission line(s)” and “applicable line(s)” can also refer to the generation Facilities as referenced in 4.3 and its subsections.

<sup>1</sup> EPAAct 2005 section 1211c: “Access approvals by Federal agencies”.

4.3.1.3. Operated below 200kV having been identified as included in the definition of one of the Major WECC Transfer Paths in the Bulk Electric System.

**4.3.—Enforcement:** *The reliability obligations of the applicable entities and facilities are contained within the technical requirements of this standard. [Straw proposal]*

4.4.

**5. Background:**

This NERC Vegetation Management Standard (“Standard”) uses a defense-in-depth approach to improve the reliability of the electric Transmission System by preventing those vegetation related outages that could lead to Cascading. This Standard is not intended to address non-preventable outages such as those due to vegetation fall-ins or blow-ins from outside the Right-of-Way, vandalism, human activities and acts of nature. Operating experience indicates that trees that have grown out of specification have contributed to Cascading, especially under heavy electrical loading conditions.

With a defense-in-depth strategy, this Standard utilizes three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

- a) Performance-based — defines a particular reliability objective or outcome to be achieved.
- b) Risk-based — preventive requirements to reduce the risks of failure to acceptable tolerance levels.
- c) Competency-based — defines a minimum capability an entity needs to have to demonstrate it is able to perform its designated reliability functions.

The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard. For this Standard, the requirements have been developed as follows:

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

Thus the various requirements associated with a successful vegetation program could be viewed as using R1, R2 and R3 as first levels of defense; while R4 could be a subsequent or

final level of defense. R6 depending on the particular vegetation approach may be either an initial defense barrier or a final defense barrier.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the Standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the Standard the term “public lands” includes municipal lands, village lands, city lands, and a host of other governmental entities.

This Standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This Standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this Standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of multiple line failures and Cascading. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are statistically intermittent. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this Standard’s emphasis is on vegetation grow-ins.

Requirements and Measures

**R1.** Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ shall manage vegetation to prevent encroachments of the types shown below, into the Minimum Vegetation Clearance Distance (MVCD) of any of its applicable line(s) identified as an element of an Interconnection Reliability Operating Limit (IROL) in the planning horizon by the Planning Coordinator; or Major Western Electricity Coordinating Council (WECC) transfer path(s); operating within its Rating and all Rated Electrical Operating Conditions.<sup>2</sup>

1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,
2. An encroachment due to a fall-in from inside the Right-of-Way (ROW) that caused a vegetation-related Sustained Outage,
3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,
4. An encroachment due to a grow-in that caused a vegetation-related Sustained Outage. *[VRF – High] [Time Horizon – Real-time]*

**M1.** Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments.

If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

**Rationale**

The MVCD is a calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages. The distances in Table 2 were derived using a proven transmission design method. The types of failure to manage vegetation are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable Transmission Owner’s or applicable Generator Owner’s a TO’s vegetation maintenance program since the encroachments listed require different and increasing levels of skills and knowledge and thus constitute a logical progression of how well, or poorly, an applicable Transmission Owner or applicable Generator Owner a-TO manages vegetation relative to this Requirement.

<sup>2</sup> This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation. Nothing in this footnote should be construed to limit the applicable Transmission Owner’s or applicable Generator Owner ~~Transmission Owner~~’s right to exercise its full legal rights on the ROW.

Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period. (R1)

- R2.** Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ shall manage vegetation to prevent encroachments of the types shown below, into the MVCD of any of its applicable line(s) that is not an element of an IROL; or Major WECC transfer path; operating within its Rating and all Rated Electrical Operating Conditions.<sup>2</sup>
1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,
  2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,
  3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,
  4. An encroachment due to a grow-in that caused a vegetation-related Sustained Outage.
- [VRF – Medium] [Time Horizon – Real-time]*

**Rationale**

The MVCD is a calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages. The distances in Table 2 were derived using a proven transmission design method. The types of failure to manage vegetation are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable Transmission Owner’s or applicable Generator Owner’s ~~TO’s~~ vegetation maintenance program since the encroachments listed require different and increasing levels of skills and knowledge and thus constitute a logical progression of how well, or poorly, an applicable Transmission Owner or applicable Generator Owner ~~TO~~ manages vegetation relative to this Requirement.

- M2.** Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments.

If a later confirmation of a Fault by the applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period. (R2)



**R3.** Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable transmission lines that include(s) the following:

- 3.1** Accounts for the movement of applicable transmission line conductors under their Facility Rating and all Rated Electrical Operating Conditions;
- 3.2** Accounts for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

**Rationale**

The documentation provides a basis for evaluating the competency of the applicable Transmission Owner's or applicable Generator Owner's ~~Transmission Owner's~~ vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ avoids vegetation-to-wire conflicts under all Rated Electrical Operating Conditions. See Figure 1 for an illustration of possible conductor locations.

*[VRF – Lower] [Time Horizon – Long Term Planning]*

**M3.** The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

**R4.** Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable transmission line when the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment.

**Rationale**

To ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ and the control center when a critical situation is confirmed.

*[VRF – Medium] [Time Horizon – Real-time]*

**M4.** Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

**R5.** When a applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ is constrained from performing vegetation work, and the constraint may lead to a vegetation encroachment into the MVCD of its applicable transmission lines prior to the implementation of the next annual work plan then the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ shall take corrective action to ensure continued vegetation management to prevent encroachments.

*[VRF – Medium] [Time Horizon – Operations Planning]*

**Rationale**

Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ to put interim measures in place, rather than do nothing.

The corrective action process is intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

**M5.** Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, and evidence that a line was de-energized. (R5)

**R6.** Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 months between inspections on the same ROW.<sup>3</sup>

*[VRF – Medium] [Time Horizon – Operations Planning]*

**Rationale**

Inspections are used by applicable Transmission Owners and applicable Generator Owners ~~Transmission Owners~~ to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Applicable Transmission Owners and applicable Generator Owners ~~Transmission Owners~~ should consider local and environmental factors that could warrant more frequent inspections.

<sup>3</sup> When the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the applicable Transmission Owner or applicable Generator Owner ~~TO~~ is granted a time extension that is equivalent to the duration of the time the applicable Transmission Owner or applicable Generator Owner ~~TO~~ was prevented from performing the Vegetation Inspection.



**M6.** Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable transmission lines at least once per calendar year but with no more than 18 months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

**R7.** Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ shall complete 100% of its annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not put the transmission system at risk of a vegetation encroachment) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include:

**Rationale**

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. An annual vegetation work plan allows for work to be modified for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that the changes do not violate the encroachment within the MVCD.

- Change in expected growth rate/ environmental factors
  - Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~<sup>4</sup>
  - Rescheduling work between growing seasons
  - Crew or contractor availability/ Mutual assistance agreements
  - Identified unanticipated high priority work
  - Weather conditions/Accessibility
  - Permitting delays
  - Land ownership changes/Change in land use by the landowner
  - Emerging technologies
- [VRF – Medium] [Time Horizon – Operations Planning]*

**M7.** Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ has evidence that it completed its annual vegetation work plan. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (including modifications if any), dated work orders, dated invoices, or dated inspection records. (R7)

<sup>4</sup> Circumstances that are beyond the control of a applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner ~~TO~~ or an applicable regulatory body, ice storms, and floods; arboricultural, horticultural or agricultural activities.

## Compliance

### Compliance Enforcement Authority

- Regional Entity

### Compliance Monitoring and Enforcement Processes:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints
- Periodic Data Submittals

### Evidence Retention

The ~~applicable Transmission Owner and applicable Generator Owner~~ Transmission Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, Measures M1, M2, M3, M5, M6 and M7 for three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The ~~applicable Transmission Owner and applicable Generator Owner~~ Transmission Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an ~~applicable Transmission Owner or applicable Generator Owner~~ Transmission Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

### Additional Compliance Information

**Periodic Data Submittal:** The ~~applicable Transmission Owner and applicable Generator Owner~~ Transmission Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable transmission lines determined by the ~~applicable Transmission Owner or applicable Generator Owner~~ Transmission Owner to have been caused by vegetation, except as excluded in footnote 2, which includes as a minimum, the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the ~~applicable Transmission Owner or applicable Generator Owner~~ Transmission Owner.

A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable transmission lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable transmission lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable transmission lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable transmission lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable transmission lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable transmission lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable transmission lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners~~Transmission Owners~~, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

Time Horizons, Violation Risk Factors, and Violation Severity Levels

Table 1						
R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Real-time	High	The <del>Transmission Owner</del> responsible entity had an encroachment into the MVCD observed in Real-time, absent a Sustained Outage.	The <del>Transmission Owner</del> responsible entity had an encroachment into the MVCD due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage.	The <del>Transmission Owner</del> responsible entity had an encroachment into the MVCD due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage.	The <del>Transmission Owner</del> responsible entity had an encroachment into the MVCD due to a grow-in that caused a vegetation-related Sustained Outage.
R2	Real-time	Medium	The <del>Transmission Owner</del> responsible entity had an encroachment into the MVCD observed in Real-time, absent a Sustained Outage.	The <del>Transmission Owner</del> responsible entity had an encroachment into the MVCD due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage.	The <del>Transmission Owner</del> responsible entity had an encroachment into the MVCD due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage.	The <del>Transmission Owner</del> responsible entity had an encroachment into the MVCD due to a grow-in that caused a vegetation-related Sustained Outage.
R3	Long-Term	Lower		The <del>Transmission Owner</del> responsible	The <del>Transmission</del>	The <del>Transmission</del>

	Planning			<u>entity</u> has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the <del>Transmission</del> <u>Ownerresponsible entity</u> 's applicable lines.	<del>Ownerresponsible entity</del> has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the <del>Transmission</del> <u>Ownerresponsible entity</u> 's applicable lines.	<del>Ownerresponsible entity</del> does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the <del>Transmission</del> <u>Ownerresponsible entity</u> 's applicable lines.
R4	Real-time	Medium			The <del>Transmission</del> <u>Ownerresponsible entity</u> experienced a confirmed vegetation threat and notified the control center holding switching authority for that transmission line, but there was intentional delay in that notification.	The <del>Transmission</del> <u>Ownerresponsible entity</u> experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that transmission line.
R5	Operations Planning	Medium				The <del>Transmission</del> <u>Ownerresponsible entity</u> did not take corrective action when it was constrained from performing planned vegetation work where a transmission line was put at potential risk.
R6	Operations Planning	Medium	The <del>Transmission</del> <u>Ownerresponsible entity</u> failed to inspect 5% or	The <del>Transmission</del> <u>Ownerresponsible entity</u> failed to inspect more than 5% up to and including 10% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers,	The <del>Transmission</del> <u>Ownerresponsible entity</u> failed to inspect more than 10% up to and including 15% of its applicable transmission lines (measured in units of	The <del>Transmission</del> <u>Ownerresponsible entity</u> failed to inspect more than 15% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or

			less of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	etc.).	choice - circuit, pole line, line miles or kilometers, etc.).	kilometers, etc.).
R7	Operations Planning	Medium	The <del>Transmission Owner</del> <u>responsible entity</u> failed to complete up to 5% of its annual vegetation work plan (including modifications if any).	The <del>Transmission Owner</del> <u>responsible entity</u> failed to complete more than 5% and up to 10% of its annual vegetation work plan (including modifications if any).	The <del>Transmission Owner</del> <u>responsible entity</u> failed to complete more than 10% and up to 15% of its annual vegetation work plan (including modifications if any).	The <del>Transmission Owner</del> <u>responsible entity</u> failed to complete more than 15% of its annual vegetation work plan (including modifications if any).

**Variances**

None.

**Interpretations**

None.

## Guideline and Technical Basis

### Requirements R1 and R2:

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the prevention of vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each ~~Transmission-applicable Transmission Owner and applicable Generator Owner~~ ~~Owner~~ to manage vegetation to prevent encroachment within the Minimum Vegetation Clearance Distance (“MVCD”) of transmission lines. R1 is applicable to lines “identified as an element of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path (operating within Rating and Rated Electrical Operating Conditions) to avoid a Sustained Outage”. R2 applies to all other applicable lines that are not an element of an IROL or Major WECC Transfer Path.

The separation of applicability (between R1 and R2) recognizes that an encroachment into the MVCD of an IROL or Major WECC Transfer Path transmission line is a greater risk to the electric transmission system. Applicable lines that are not an element of an IROL or Major WECC Transfer Path are required to be clear of vegetation but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

These requirements (R1 and R2) state that if vegetation encroaches within the distances in Table 1 in Appendix 1 of this supplemental Transmission Vegetation Management Standard FAC-003-2 Technical Reference document, it is in violation of the standard. Table 2 tabulates the distances necessary to prevent spark-over based on the Gallet equations as described more fully in Appendix 1 below.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating (potentially in violation of other standards), the occurrence of a clearance encroachment may occur. For example, emergency actions taken by a Transmission Operator or Reliability Coordinator to protect an Interconnection may cause the transmission line to sag more and come closer to vegetation, potentially causing an outage. Such vegetation-related outages are not a violation of these requirements.

Evidence of violation of Requirement R1 and R2 include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to blowing together of applicable lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. If an investigation of a Fault by an ~~Transmission-applicable Transmission Owner or applicable Generator Owner~~ ~~Owner~~ confirms that a vegetation encroachment within the MVCD occurred, then it shall be considered the equivalent of a Real-time observation.

With this approach, the VSLs were defined such that they directly correlate to the severity of a failure of an ~~an Transmission-applicable Transmission Owner and applicable Generator Owner~~ ~~Owner~~ to manage vegetation and to the corresponding performance level of the ~~Transmission applicable Transmission Owner’s or applicable Generator Owner’s~~ ~~Owner’s~~ vegetation



program's ability to meet the goal of "preventing a Sustained Outage that could lead to Cascading." Thus violation severity increases with an ~~Transmission Own applicable Transmission Owner's or applicable Generator Owner's er's~~ inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example, a limb may only partially break and intermittently contact a conductor. Such events are considered to be a single vegetation-related Sustained Outage under the Standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of ~~Transmission~~ Facilities. Keeping vegetation from entering this space will prevent transmission outages.

### Requirement R3:

Requirement R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an ~~Transmission-applicable Transmission Owner or applicable Generator Owner Owner~~ uses for vegetation management.

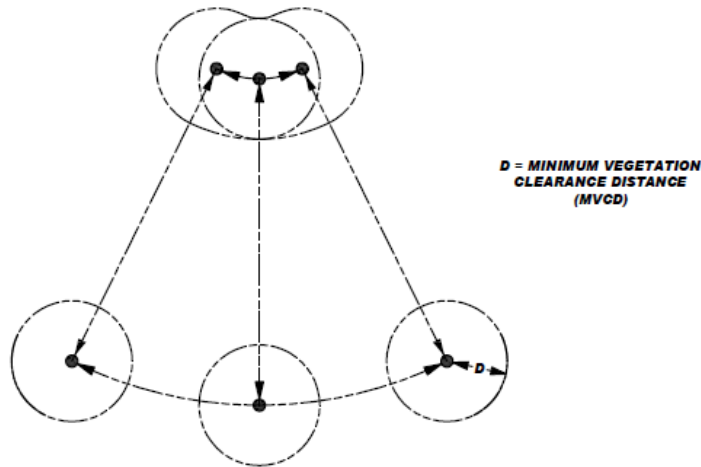
An adequate transmission vegetation management program formally establishes the approach the ~~Transmission-applicable Transmission Owner or applicable Generator Owner Owner~~ uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the Transmission System. The approach provides the basis for evaluating the intent, allocation of appropriate resources and the competency of the ~~Transmission-applicable Transmission Owner or applicable Generator Owner Owner~~ in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the ~~Transmission applicable Transmission Owner or applicable Generator Owner Owner~~ must be able to state what its approach is and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an ~~Transmission-applicable Transmission Owner or applicable Generator Owner Owner~~ chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the ~~Transmission-applicable Transmission Owner or applicable Generator Owner Owner~~ uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing as a reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and

wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below.



**Figure 1**

Cross-section view of a single conductor at a given point along the span showing six possible conductor positions due to movement resulting from thermal and mechanical loading.

#### **Requirement R4:**

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the ~~Transmission-applicable Transmission Owner or applicable Generator Owner~~ Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an ~~an Transmission-applicable Transmission Owner's or applicable Generator Owner's~~ Owner's-employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The ~~Transmission-applicable Transmission Owner or applicable Generator Owner~~ ~~Owner~~ has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or positioning the system in recognition of the increasing risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some ~~Transmission-applicable Transmission Owners or applicable Generator Owners~~ ~~Owners~~ may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

#### **Requirement R5:**

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the ~~Transmission-applicable Transmission Owner or applicable Generator Owner~~ ~~Owner~~ for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the ~~Transmission-applicable Transmission Owner or applicable Generator Owner~~ ~~Owner~~ from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the ~~Transmission-applicable Transmission Owner's or applicable Generator Owner's~~ ~~Owner's~~ rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the ~~Transmission-applicable Transmission Owner or applicable Generator Owner~~ ~~Owner~~ is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the ~~Transmission-applicable Transmission Owner or applicable Generator Owner~~ ~~Owner~~ is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the ~~Transmission-applicable Transmission Owner or applicable Generator Owner~~ ~~Owner~~ is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for each location.

- In developing the specific action to mitigate the potential risk to the transmission line the ~~Transmission-applicable Transmission Owner or applicable Generator Owner~~ Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The ~~Transmission-applicable Transmission Owner or applicable Generator Owner~~ Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

**Requirement R6:**

R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections that fits general industry practice. In addition, the fact that Vegetation Inspections can be performed in conjunction with general line inspections further facilitates an ~~Transmission-applicable Transmission Owner’s or applicable Generator Owner’s~~ Owner’s ability to meet this requirement. However, the ~~Transmission-applicable Transmission Owner or applicable Generator Owner~~ Owner may determine that more frequent inspections are needed to maintain reliability levels, dependent upon such factors as anticipated growth rates of the local vegetation, length of the growing season for the geographical area, limited ROW width, and rainfall amounts. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSL for Requirement R6 has VSL categories ranked by the percentage of the required ROW inspections completed. To calculate the percentage of inspection completion, the ~~Transmission applicable Transmission Owner or applicable Generator Owner~~ Owner may choose units such as: line miles or kilometers, circuit miles or kilometers, pole line miles, ROW miles, etc.

For example, when an ~~Transmission-applicable Transmission Owner or applicable Generator Owner~~ Owner operates 2,000 miles of 230 kV transmission lines this ~~Transmission-applicable Transmission Owner or applicable Generator Owner~~ Owner will be responsible for inspecting all 2,000 miles of 230 kV transmission lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be  $100/2000 = 0.05$  or 5%. The “Low VSL” for R6 would apply in this example.

**Requirement R7:**

R7 is a risk-based requirement. The ~~Transmission-applicable Transmission Owner or applicable Generator Owner~~ Owner is required to implement an annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and

documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a “span-by-span”, or even a “line-by-line” detailed description of all work to be performed. It is only intended to require that the ~~Transmission-applicable Transmission Owner or applicable Generator Owner Owner~~ provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

The ability to modify the work plan allows the ~~Transmission-applicable Transmission Owner or applicable Generator Owner Owner~~ to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the ~~Transmission-applicable Transmission Owner’s or applicable Generator Owner’s Owner’s~~ system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan. Modifications to the annual work plan must always ensure the reliability of the electric Transmission system.

In general, the vegetation management maintenance approach should use the full extent of the ~~Transmission-applicable Transmission Owner’s or applicable Generator Owner’s Owner’s~~ easement, fee simple and other legal rights allowed. -A comprehensive approach that exercises the full extent of legal rights on the -ROW is superior to incremental management in the long term because it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the ~~Transmission-applicable Transmission Owner or applicable Generator Owner Owner~~ should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. ~~Transmission-Applicable Transmission Owners or applicable Generator Owners Owners~~ may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the ~~applicable Transmission Owner or applicable Generator Owner Transmission Owner~~, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)<sup>5</sup>  
For Alternating Current Voltages

( AC ) Nominal System Voltage (kV)	( AC ) Maximum System Voltage (kV)	MVCD feet (meters) sea level	MVCD feet (meters) 3,000ft (914.4m)	MVCD feet (meters) 4,000ft (1219.2m)	MVCD feet (meters) 5,000ft (1524m)	MVCD feet (meters) 6,000ft (1828.8m)	MVCD feet (meters) 7,000ft (2133.6m)	MVCD feet (meters) 8,000ft (2438.4m)	MVCD feet (meters) 9,000ft (2743.2m)	MVCD feet (meters) 10,000ft (3048m)	MVCD feet (meters) 11,000ft (3352.8m)
765	800	8.06ft (2.46m)	8.89ft (2.71m)	9.17ft (2.80m)	9.45ft (2.88m)	9.73ft (2.97m)	10.01ft (3.05m)	10.29ft (3.14m)	10.57ft (3.22m)	10.85ft (3.31m)	11.13ft (3.39m)
500	550	5.06ft (1.54m)	5.66ft (1.73m)	5.86ft (1.79m)	6.07ft (1.85m)	6.28ft (1.91m)	6.49ft (1.98m)	6.7ft (2.04m)	6.92ft (2.11m)	7.13ft (2.17m)	7.35ft (2.24m)
345	362	3.12ft (0.95m)	3.53ft (1.08m)	3.67ft (1.12m)	3.82ft (1.16m)	3.97ft (1.21m)	4.12ft (1.26m)	4.27ft (1.30m)	4.43ft (1.35m)	4.58ft (1.40m)	4.74ft (1.44m)
230	242	2.97ft (0.91m)	3.36ft (1.02m)	3.49ft (1.06m)	3.63ft (1.11m)	3.78ft (1.15m)	3.92ft (1.19m)	4.07ft (1.24m)	4.22ft (1.29m)	4.37ft (1.33m)	4.53ft (1.38m)
161*	169	2ft (0.61m)	2.28ft (0.69m)	2.38ft (0.73m)	2.48ft (0.76m)	2.58ft (0.79m)	2.69ft (0.82m)	2.8ft (0.85m)	2.91ft (0.89m)	3.03ft (0.92m)	3.14ft (0.96m)
138*	145	1.7ft (0.52m)	1.94ft (0.59m)	2.03ft (0.62m)	2.12ft (0.65m)	2.21ft (0.67m)	2.3ft (0.70m)	2.4ft (0.73m)	2.49ft (0.76m)	2.59ft (0.79m)	2.7ft (0.82m)
115*	121	1.41ft (0.43m)	1.61ft (0.49m)	1.68ft (0.51m)	1.75ft (0.53m)	1.83ft (0.56m)	1.91ft (0.58m)	1.99ft (0.61m)	2.07ft (0.63m)	2.16ft (0.66m)	2.25ft (0.69m)
88*	100	1.15ft (0.35m)	1.32ft (0.40m)	1.38ft (0.42m)	1.44ft (0.44m)	1.5ft (0.46m)	1.57ft (0.48m)	1.64ft (0.50m)	1.71ft (0.52m)	1.78ft (0.54m)	1.86ft (0.57m)
69*	72	0.82ft (0.25m)	0.94ft (0.29m)	0.99ft (0.30m)	1.03ft (0.31m)	1.08ft (0.33m)	1.13ft (0.34m)	1.18ft (0.36m)	1.23ft (0.37m)	1.28ft (0.39m)	1.34ft (0.41m)

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above).

<sup>5</sup> The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

**Table 2 (cont.) — Minimum Vegetation Clearance Distances (MVCD)  
For Direct Current Voltages**

( DC ) Nominal Pole to Ground Voltage (kV)	MVCD feet (meters) sea level	MVCD feet (meters) 3,000ft (914.4m) Alt.	MVCD feet (meters) 4,000ft (1219.2m) Alt.	MVCD feet (meters) 5,000ft (1524m) Alt.	MVCD feet (meters) 6,000ft (1828.8m) Alt.	MVCD feet (meters) 7,000ft (2133.6m) Alt.	MVCD feet (meters) 8,000ft (2438.4m) Alt.	MVCD feet (meters) 9,000ft (2743.2m) Alt.	MVCD feet (meters) 10,000ft (3048m) Alt.	MVCD feet (meters) 11,000ft (3352.8m) Alt.
±750	13.92ft (4.24m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.9ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.07ft (3.07m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	(13.54ft 4.13m)
±500	7.89ft (2.40m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	4.78ft (1.46m)	5.35ft (1.63m)	5.55ft (1.69m)	5.75ft (1.75m)	5.95ft (1.81m)	6.15ft (1.87m)	6.36ft (1.94m)	6.57ft (2.00m)	6.77ft (2.06m)	6.98ft (2.13m)
±250	3.43ft (1.05m)	4.02ft (1.23m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5ft (1.52m)	5.17ft (1.58m)

Notes:

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet Equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:



- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 uses the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-01 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 5 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 7 would have to be used. Table 7 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines, as such, are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line is approximately 2.0 per unit. This value is a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.



Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 242 kV and below is considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at 362 kV and above a transient over-voltage factor of 1.4 per unit is considered a realistic maximum.

The Gallet Equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet Equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America [1].

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

While EPRI is currently trying to establish empirical data for spark-over distances to live vegetation, there are no spark-over formulas currently derived expressly for vegetation to conductor minimum distances. Therefore the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations using various transient overvoltage values.

**Comparison of spark-over distances computed using Gallet wet equations  
vs.  
IEEE 516-2003 MAID distances  
using various transient over-voltage factors**

( AC ) Nom System Voltage (kV)	( AC ) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 feet	Table 5 IEEE 516 MAID (ft) @ Alt. 3000 feet
765	800	1.4	8.89	8.65
500	550	1.4	5.65	4.92
345	362	1.4	3.52	3.13
230	242	2.0	3.35	2.8
115	121	2.0	1.6	1.4

( AC ) Nom System Voltage (kV)	( AC ) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 feet	Table 5 (historical maximums) IEEE 516 MAID (ft) @ Alt. 3000 feet
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

<b>( AC ) Nom System Voltage (kV)</b>	<b>( AC ) Max System Voltage (kV)</b>	<b>Transient Over-voltage Factor (T)</b>	<b>Clearance (ft.) Gallet (wet) @ Alt. 3000 feet</b>	<b>Table 7 IEEE 516 MAID (ft) @ Alt. 3000 feet</b>
765	800	2.5	20.25	20.4
500	550	3.0	15.02	14.7
345	362	3.5	10.42	9.44
230	242	3.5	6.32	5.14
115	121	3.5	2.90	2.45

## Implementation Plan for FAC-003-3 – Vegetation Management

### Prerequisite Approvals

FAC-003-2 – Vegetation Management must be implemented before this standard can be implemented.

### Revision to Sections of Approved Standards and Definitions

There are no proposed revisions to requirements in other already approved standards. All requirements and the two revised definitions in the proposed standard FAC-003-2 will be retired when FAC-003-3 becomes effective.

### Compliance with Standard

There are no changes to the requirements applicable to Transmission Owners already proposed in FAC-003-2, and the expectation is that Transmission Owners will maintain their current state of compliance. Thus, the standard is effective for Transmission Owners upon approval, as detailed below.

The proposed changes to Version 2 of the standard only address Generator Owner applicability and requirements (add Generator Owner to sections 4.1.2 and 4.3 and add applicable Generator Owner to all requirements). Therefore, this implementation plan only identifies a compliance timeframe for Generator Owners to which this standard will apply.

To reach compliance with the standard, a Generator Owner will have to perform a full review of as-built drawings and determine which generation interconnection Facilities require a Transmission Vegetation Management Plan (TVMP) and inspection as specified by NERC Reliability Standard FAC-003-3. In general, Generator Owners do not have staff that are qualified and experienced to create a TVMP, perform Right-of-Way inspections, and perform any required tree trimming (as is required by FAC-003-3 Requirement 1.3). Once a complete inventory is created, the Generator Owner will begin the process of gathering information for the TVMP. In instances where the generation interconnection Facilities are owned by a partnership, a majority or operating partner will need to obtain partnership approval to proceed with procurement of a TVMP expert, and later a tree trimming crew. Typically, a request for proposal to hire TVMP consultant is initiated which could take several weeks in order to obtain sufficient bids (and also satisfy Sarbanes Oxley requirements). Once all bids have been received, a contract with a TVMP consultant is signed. At this point, the TVMP consultant and Generator Owner staff will develop the TVMP, which needs to take into account local growth conditions, types of vegetation and other aspects required by FAC-003. Once the TVMP is developed, Generator Owner staff and the TVMP consultant will need to perform a Right-of-Way inspection (as required in FAC-003-3 Requirement 1), usually done using GPS, LIDAR and other tools by experienced and qualified staff.

Once a Right-of-Way inspection is completed and clearances are required, the Generator Owner will need to issue a request for proposal to hire a tree trimming crew that is qualified and experienced to perform required clearance trimming. Once all bids have been received, a contract with a tree trimming crew is signed. When the tree trimming crew is acquired, the crew will need to familiarize themselves with the entity's TVMP and required clearances. The Generator Owner will typically need to schedule any required outages in order for the tree

trimming crew to perform the needed clearance trimming. This action would also include the implementation of the work plan as required in FAC-003-3 Requirement 2. During scheduled outages, if required, the tree trimming crew will perform any required clearances and document the activities.

Another typical action is the Generator Owner establishing a system for maintaining TVMP-related activities, including maintenance of inspection and clearance documentation (as required in FAC-003-3 Requirement 1.2). On an ongoing basis, in addition to performing inspections and clearances as required by the entity's TVMP, the Generator Owner will need to ensure that the training and qualification requirements for the standard are met. The entity will also need to maintain documentation of all FAC-003-3 activities for compliance period of one year to meet compliance with the standard.

Again, due to a typical lack of experience and qualifications required by FAC-003-3, compliance with this standard by a Generator Owner may take as long as two years – in part because many entities will have generator interconnection Facilities in various parts of the country which may require several instances of TVMP and numerous Right-of-Way inspections.

### **Effective Date**

There are three effective dates associated with this implementation plan:

The first effective date applies to Transmission Owners.

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner become effective upon Board of Trustees' adoption.

The second effective date allows Generator Owners time to develop documented maintenance strategies or procedures or processes or specifications as outlined in Requirement R3.

In those jurisdictions where regulatory approval is required, Requirement R3 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The third effective date allows entities time to comply with Requirements R1, R2, R4, R5, R6, and R7.

In those jurisdictions where regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for is required. In those jurisdictions where no regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

Exceptions:

A line operated below 200kV, designated by the Planning Coordinator as an element of an IROL or as a Major WECC transfer path, becomes subject to this standard 12 months after the date the Planning Coordinator or WECC initially designates the line as being subject to this standard.

An existing transmission line operated at 200kV or higher that is newly acquired by an asset owner and was not previously subject to this standard, becomes subject to this standard 12 months after the acquisition date of the line.

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary. When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.*

### **Right-of-Way (ROW)**

A corridor of land on which electric lines may be located. The applicable Transmission Owner or applicable Generator Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

The current glossary definition of this NERC term was modified to include applicable Generator Owners.

FAC-003-2 is currently under development under Project 2007-07. The project is nearing its final stages, but the Project 2010-07 drafting team does not want to assume that the project will be approved by NERC's Board or Trustees (BOT) or FERC. Thus, the Project 2010-07 drafting team has developed two sets of proposed changes: one to this version, FAC-003-1, the current FERC-approved version of the standard, and one to FAC-003-2, the latest draft of Version 2 as proposed by the Project 2007-07 team

If FAC-003-2 is approved by NERC's BOT, the Project 2010-07 drafting team will likely proceed with the modifications it has proposed in the redline to that version of the standard. These changes would be submitted for stakeholder approval and balloted as FAC-003-3. FAC-003-2 would be retired once FAC-003-3 was approved.

If, however, FAC-003-2 remains under development, the Project 2010-07 drafting team will proceed with the changes to FAC-003-1 seen below to avoid further delay of its project goals. Changes to FAC-003-1 would address the addition of Generator Owners to the applicability section, modifications to the NERC defined terms Right-of-Way to include Generator Owners, and some formatting changes to bring the standard up to date. These changes would not be comprehensive; rather, they would aim to include the generator interconnection Facility in the standard with as few other changes as possible.

## **A. Introduction**

**1. Title: Transmission Vegetation Management Program**

**2. Number: FAC-003-X**

**3. Purpose:** To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation-related outages of the transmission systems to the respective Regional Entity (RE) and the North American Electric Reliability Council (NERC).

Within the text of NERC Reliability Standard FAC-003-X, "transmission line(s)" and "applicable line(s)" can also refer to the generation Facilities as referenced in 4.4 and its subsections.

### **4. Applicability:**

**4.1. Regional Entity.**

**4.2. Applicable Transmission Owner**

**4.2.1.** Transmission Owner that owns overhead transmission lines operated at 200 kV and above and to any lower voltage lines designated by the RE as critical to the reliability of the electric system in the region.

**4.3. Applicable Generator Owner**

**4.3.1.** Generator Owner that owns an overhead Facility that extends greater than one half mile beyond the fenced area of the switchyard, generating station or generating substation up to the point of interconnection with the Transmission system and is operated at 200 kV and above and any lower voltage lines designated by the RE as critical to the reliability of the electric system in the region.

### **5. Effective Dates:**

There are three effective dates associated with this implementation plan:

The first effective date applies to Transmission Owners.



In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner become effective upon Board of Trustees' adoption.

The second effective date allows Generator Owners time to prepare a formal transmission vegetation management program as outlined in Requirement R1.

In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The third effective date allows entities time to comply with Requirements R2, R3, and R4.

In those jurisdictions where regulatory approval is required, Requirements R2, R3, and R4 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for is required. In those jurisdictions where no regulatory approval is required, Requirements R2, R3, and R4 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

## **B. Requirements**

**R1.** Each applicable Transmission Owner or applicable Generator Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the applicable Transmission Owner's or applicable Generator Owner's objectives, practices, approved procedures, and work specifications<sup>1</sup>.

**R1.1.** The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the applicable Transmission Owner's or applicable Generator Owner's transmission lines.

**R1.2.** Each applicable Transmission Owner or applicable Generator Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the applicable Transmission Owner or applicable Generator Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.

**R1.2.1.** Clearance 1 — The applicable Transmission Owner or applicable Generator Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the applicable

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<sup>1</sup> ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.

Transmission Owner or applicable Generator Owner plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.

**R1.2.2.** Clearance 2 — The applicable Transmission Owner or applicable Generator Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These applicable Transmission Owner-specific or applicable Generator Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.

**R1.2.2.1** Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.

**R1.2.2.2** Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.

**R1.3.** All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner or Generator Owner, to perform their duties.

**R1.4.** Each applicable Transmission Owner or applicable Generator Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner or applicable Generator Owner is restricted from attaining the clearances specified in Requirement 1.2.1.

**R1.5.** Each Transmission Owner or applicable Generator Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.

[VRF – High]

**R2.** Each applicable Transmission Owner or applicable Generator Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or

regulatory authorities. Each applicable Transmission Owner or applicable Generator Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.

*[VRF – High]*

- R3.** Each applicable Transmission Owner or applicable Generator Owner shall report quarterly to its RE, or the RE's designee, sustained transmission line outages determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation.
- R3.1.** Multiple sustained 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.
- R3.2.** The applicable Transmission Owner or applicable Generator Owner is not required to report to the RE, or the RE's designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).
- R3.3.** The outage information provided by the applicable Transmission Owner or applicable Generator Owner to the RE, or the RE's designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.
- R3.4.** An outage shall be categorized as one of the following:
- R3.4.1.** Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;
  - R3.4.2.** Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;
  - R3.4.3.** Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.

*[VRF – Lower]*

- R4.** The RE shall report the outage information provided to it by applicable Transmission Owners or applicable Generator Owners, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the RE as a result of any of the reported outages.

*[VRF – Lower]*

**C. Measures**

- M1.** Each applicable Transmission Owner or applicable Generator Owner has a documented TVMP, as identified in Requirement 1.

- M1.1.** Each applicable Transmission Owner or applicable Generator Owner has documentation that the applicable Transmission Owner or applicable Generator Owner performed the vegetation inspections as identified in Requirement 1.1.
- M1.2.** Each applicable Transmission Owner or applicable Generator Owner has documentation that describes the clearances identified in Requirement 1.2.
- M1.3.** Each applicable Transmission Owner or applicable Generator Owner has documentation that the personnel directly involved in the design and implementation of the applicable Transmission Owner's or applicable Generator Owner TVMP hold the qualifications identified by the Transmission Owner or applicable Generator Owner as required in Requirement 1.3.
- M1.4.** Each applicable Transmission Owner or applicable Generator Owner has documentation that it has identified any areas not meeting the applicable Transmission Owner's or applicable Generator Owner's standard for vegetation management and any mitigating measures the Transmission Owner or applicable Generator Owner has taken to address these deficiencies as identified in Requirement 1.4.
- M1.5.** Each applicable Transmission Owner or applicable Generator Owner has a documented process for the immediate communication of imminent threats by vegetation as identified in Requirement 1.5.
- M2.** Each applicable Transmission Owner or applicable Generator Owner has documentation that the Transmission Owner implemented the work plan identified in Requirement 2.
- M3.** Each applicable Transmission Owner or applicable Generator Owner has documentation that it has supplied quarterly outage reports to the RE, or the RE's designee, as identified in Requirement 3.
- M4.** The RE has documentation that it provided quarterly outage reports to NERC as identified in Requirement 4.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

Compliance Monitor:

- Regional Entity for the Transmission Owner and Generator Owner
- Electric Reliability Organization or another Regional Entity for the Regional Entity

**1.2. Compliance Monitoring and Enforcement Processes:**

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

**1.3. Data Retention**

The applicable Transmission Owner and applicable Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance

Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The applicable Transmission Owner and applicable Generator Owner shall retain evidence of Requirement 1, Measure 1, Requirement 2, Measure 2, and Requirement 3, Measure 3 from its last audit.

**1.4. Additional Compliance Information**

None.

**2. Violation Severity Levels**

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity did not include and keep current one of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current two of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current three of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current all required elements of the TVMP, as directed by the requirement.
R1.1	N/A	N/A	The applicable entity TVMP did not define a schedule, as directed by the requirement, or the type of ROW vegetation inspections, as directed by the requirement.	The applicable entity TVMP did not define a schedule, as directed by the requirement, nor the type of ROW vegetation inspections, as directed by the requirement.
R1.2	N/A	N/A	N/A	The responsible entity, in its TVMP, failed to identify and document clearances between vegetation and any overhead, ungrounded supply conductors.  OR  The responsible entity, in its TVMP, failed to take into

				<p>consideration transmission line voltage, or the effects of ambient temperature on conductor sag under maximum design loading, or the effects of wind velocities on conductor sway.</p> <p>OR</p> <p>The responsible entity, in its TVMP, failed to establish Clearance 1 or Clearance 2 values.</p>
R1.2.1	N/A	N/A	N/A	<p>The responsible entity failed to determine and document an appropriate clearance distance to be achieved at the time of transmission vegetation management work taking into account local conditions and the expected time frame in which the responsible entity expects to return for future vegetation management work.</p> <p>OR</p> <p>The responsible entity documented a Clearance 1 value that was smaller than its Clearance 2 value.</p>

R1.2.2	N/A	N/A	N/A	The responsible entity failed to determine and document Clearance 2 values taking into account local conditions and the expected time frame in which the responsible entity expects to return for future vegetation management work.
R1.2.2.1	N/A	N/A	N/A	Where transmission system transient overvoltage factors were known, clearances were not derived from Table 5, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.
R1.2.2.2	N/A	N/A	N/A	Where transmission system transient overvoltage factors are known, clearances were not derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.
R1.3	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, one of those persons did not hold appropriate qualifications and	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, two of those persons did not hold appropriate qualifications and	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, three of those persons did not hold appropriate qualifications and	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, more than three of those persons did not hold appropriate qualifications and

	training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, 5% or less of those persons did not hold appropriate qualifications and training to perform their duties.	training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 5% up to (and including) 10% of those persons did not hold appropriate qualifications and training to perform their duties.	training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 10% up to (and including) 15% of those persons did not hold appropriate qualifications and training to perform their duties.	training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 15% of those persons did not hold appropriate qualifications and training to perform their duties.
R1.4	N/A	N/A	N/A	The responsible entity's TVMP does not include mitigation measures to achieve sufficient clearances where restrictions to the ROW are in effect.
R1.5	N/A	N/A	N/A	The responsible entity did not establish or did not document a process for the immediate communication of vegetation conditions that present an imminent threat of line outage, as directed by the requirement.
R2	The responsible entity did not meet one of the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the	The responsible entity did not meet two of the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the	The responsible entity did not meet the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the	The responsible entity does not have an annual plan for vegetation management.  OR  The responsible entity has not implemented the annual plan for vegetation



	annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	management.
R3	<p>The responsible entity failed to provide a quarterly outage report, but did not experience any reportable outages.</p> <p>OR</p> <p>The responsible entity provided a quarterly report, but failed to report in the manner specified by one or more of the following subcomponents of Requirement R3: R3.1 or R3.2.</p>	<p>The responsible entity provided a quarterly report, but failed to include information required by R3.3.</p>	<p>The responsible entity provided a quarterly outage report, but failed to include a reportable Category 3 outage as described in R3.4.3.</p>	<p>The responsible entity experienced reportable outages but failed to provide a quarterly report.</p> <p>OR</p> <p>The responsible entity provided a quarterly outage report, but failed to include a reportable Category 1 (as described in R3.4.1) or Category 2 outage (as described in R3.4.2).</p>
R4	N/A	N/A	N/A	N/A

**E. Regional Differences**

None Identified.

**Version History**

Version	Date	Action	Change Tracking
1	TBA	<ol style="list-style-type: none"> <li>1. Added “Standard Development Roadmap.”</li> <li>2. Changed “60” to “Sixty” in section A, 5.2.</li> <li>3. Added “Proposed Effective Date: April 7, 2006” to footer.</li> <li>4. Added “Draft 3: November 17, 2005” to footer.</li> </ol>	01/20/06

**Standard FAC-003-X — Transmission Vegetation Management Program**

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X	May 16, 2011	Added requirements for Generator Owner and brought overall standard format up to date	Revision under Project 2010-07

Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary. When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.*

**Right-of-Way (ROW)**

A corridor of land on which electric lines may be located. The applicable Transmission Owner or applicable Generator Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

The current glossary definition of this NERC term ~~was~~ modified to **allow both maintenance inspections and vegetation inspections to be performed concurrently** include applicable Generator Owners.

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FAC-003-2 is currently under development under Project 2007-07. The project is nearing its final stages, but the Project 2010-07 drafting team does not want to assume that the project will be approved by NERC’s Board or Trustees (BOT) or FERC. Thus, the Project 2010-07 drafting team has develop two sets of proposed changes: one to this version, FAC-003-1, the current FERC-approved version of the standard, and one to FAC-003-2, the latest draft of Version 2 as proposed by the Project 2007-07 team

If FAC-003-2 is approved by NERC’s BOT, the Project 2010-07 drafting team will likely proceed with the modifications it has proposed in the redline to that version of the standard. These changes would be submitted for stakeholder approval and balloted as FAC-003-3. FAC-003-2 would be retired once FAC-003-03 was approved.

If, however, FAC-003-2 remains under development, the Project 2010-07 drafting team will proceed with the changes to FAC-003-1 seen below to avoid further delay of its project goals. Changes to FAC-003-1 would address the addition of Generator Owners to the applicability section, modifications to the NERC defined terms Right-of-Way to include Generator Owners, and some formatting changes to bring the standard up to date. These changes would not be comprehensive; rather, they would aim to include the generator interconnection Facility in the standard with as few other changes as possible.

**A. Introduction**

**1. Title: Transmission Vegetation Management Program**

**2. Number: FAC-003-X4**

**3. Purpose:** To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation-related outages of the transmission systems to the respective Regional ~~Reliability Organizations Entity~~ (RRØRE) and the North American Electric Reliability Council (NERC).

Within the text of NERC Reliability Standard FAC-003-X, “transmission line(s)” and “applicable line(s)” can also refer to the generation Facilities as referenced in 4.4 and its subsections.

**4. Applicability:**

**4.1. Regional Entity.**

**4.2. Applicable Transmission Owner**

**4.2.1. Transmission Owner that owns overhead transmission lines operated at 200 kV and above and to any lower voltage lines designated by the RE as critical to the reliability of the electric system in the region.**

**4.3. Applicable Generator Owner**

**4.3.1. Generator Owner that owns an overhead Facility that extends greater than one half mile beyond the fenced area of the switchyard, generating station or generating substation up to the point of interconnection with the Transmission system and is operated at 200 kV and above and any lower voltage lines designated by the RE as critical to the reliability of the electric system in the region.**

~~**4.1. Transmission Owner.**~~

~~**4.2. Regional Reliability Organization.**~~

~~**4.3. This standard shall apply to all transmission lines operated at 200 kV and above and to any lower voltage lines**~~

~~designated by the RRO as critical to the reliability of the electric system in the region.~~

**5. Effective Dates:**

There are three effective dates associated with this implementation plan:

The first effective date applies to Transmission Owners.

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner become effective upon Board of Trustees' adoption.

The second effective date allows Generator Owners time to prepare a formal transmission vegetation management program as outlined in Requirement R1.

In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The third effective date allows entities time to comply with Requirements R2, R3, and R4.

In those jurisdictions where regulatory approval is required, Requirements R2, R3, and R4 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for is required. In those jurisdictions where no regulatory approval is required, Requirements R2, R3, and R4 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

~~5.1. One calendar year from the date of adoption by the NERC Board of Trustees for Requirements 1 and 2.~~

~~5.2. Sixty calendar days from the date of adoption by the NERC Board of Trustees for Requirements 3 and 4.~~

**B. Requirements**

**R1.** ~~The~~ Each applicable Transmission Owner or applicable Generator Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the applicable Transmission Owner's or applicable Generator Owner's objectives, practices, approved procedures, and work specifications<sup>1</sup>.

**R1.1.** The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the applicable Transmission Owner's or applicable Generator Owner's transmission lines.

**R1.2.** ~~Each applicable~~ The Transmission Owner or applicable Generator Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the

<sup>1</sup> ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.

effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the applicable Transmission Owner or applicable Generator Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.

**R1.2.1.** Clearance 1 — The applicable Transmission Owner or applicable Generator Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the applicable Transmission Owner or applicable Generator Owner plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.

**R1.2.2.** Clearance 2 — The applicable Transmission Owner or applicable Generator Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These applicable Transmission Owner-specific or applicable Generator Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.

**R1.2.2.1** Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.

**R1.2.2.2** Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.

**R1.3.** All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner or Generator Owner, to perform their duties.

**R1.4.** ~~Each applicable~~ Each Transmission Owner or applicable Generator Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner or applicable Generator Owner is restricted from attaining the clearances specified in Requirement 1.2.1.

**R1.5.** Each Transmission Owner or applicable Generator Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action

(temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.

*[VRF – High]*

- R2.** Each applicable ~~The~~ Transmission Owner or applicable Generator Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each applicable Transmission Owner or applicable Generator Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.

*[VRF – High]*

- R3.** Each applicable ~~The~~ Transmission Owner or applicable Generator Owner shall report quarterly to its ~~NERRO~~, or the ~~NERRO~~'s designee, sustained transmission line outages determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation.
- R3.1.** Multiple sustained 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.
- R3.2.** The applicable Transmission Owner or applicable Generator Owner is not required to report to the ~~NERRO~~, or the ~~NERRO~~'s designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).
- R3.3.** The outage information provided by the applicable Transmission Owner or applicable Generator Owner to the ~~NERRO~~, or the ~~NERRO~~'s designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.
- R3.4.** An outage shall be categorized as one of the following:
- R3.4.1.** Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;
- R3.4.2.** Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;

R3.4.3. Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.

~~[VRF – Lower]~~

R4. The ~~RERRO~~ shall report the outage information provided to it by applicable Transmission Owners or applicable Generator Owners<sup>2</sup>s, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the ~~RERRO~~ as a result of any of the reported outages.

~~R4.~~~~[VRF – Lower]~~

## C. Measures

M1. ~~Each applicable~~The Transmission Owner or applicable Generator Owner has a documented TVMP, as identified in Requirement 1.

M1.1. ~~Each applicable~~The Transmission Owner or applicable Generator Owner has documentation that the applicable Transmission Owner or applicable Generator Owner performed the vegetation inspections as identified in Requirement 1.1.

M1.2. ~~Each applicable~~The Transmission Owner or applicable Generator Owner has documentation that describes the clearances identified in Requirement 1.2.

M1.3. ~~Each applicable~~The Transmission Owner or applicable Generator Owner has documentation that the personnel directly involved in the design and implementation of the applicable Transmission Owner's or applicable Generator Owner TVMP hold the qualifications identified by the Transmission Owner or applicable Generator Owner as required in Requirement 1.3.

M1.4. ~~Each applicable~~The Transmission Owner or applicable Generator Owner has documentation that it has identified any areas not meeting the applicable Transmission Owner's or applicable Generator Owner's standard for vegetation management and any mitigating measures the Transmission Owner or applicable Generator Owner has taken to address these deficiencies as identified in Requirement 1.4.

M1.5. ~~Each applicable~~The Transmission Owner or applicable Generator Owner has a documented process for the immediate communication of imminent threats by vegetation as identified in Requirement 1.5.

M2. ~~Each applicable~~ The Transmission Owner or applicable Generator Owner has documentation that the Transmission Owner implemented the work plan identified in Requirement 2.

M3. ~~Each applicable~~The Transmission Owner or applicable Generator Owner has documentation that it has supplied quarterly outage reports to the ~~RERRO~~, or the ~~RERRO~~'s designee, as identified in Requirement 3.

M4. The ~~RERRO~~ has documentation that it provided quarterly outage reports to NERC as identified in Requirement 4.

## D. Compliance

### 1. Compliance Monitoring Process

#### ~~1.1.~~ Compliance Monitoring Responsibility Enforcement Authority

##### ~~1.2.1.1.~~

##### ~~1.1.~~ Compliance Monitor:

- ~~1.1.~~ Regional Entity for the Transmission Owner and Generator Owner



- Electric Reliability Organization or another Regional Entity for the Regional Entity

~~1.1.~~

~~RRO~~

~~NERC~~

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

~~1.2.~~ One-calendar Year ~~and Enforcement Processes:~~

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

~~E.~~ **Data Retention**

~~1.3.~~

The applicable Transmission Owner and applicable Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The applicable Transmission Owner and applicable Generator Owner shall retain evidence of Requirement 1, Measure 1, Requirement 2, Measure 2, and Requirement 3, Measure 3 from its last audit.

~~Five Years~~

~~1.1.1.4.~~ **Additional Compliance Information**

~~1.4.~~ None.

~~The Transmission Owner shall demonstrate compliance through self-certification submitted to the compliance monitor (RRO) annually that it meets the requirements of NERC Reliability Standard FAC-003-1. The compliance monitor shall conduct an on-site audit every five years or more frequently as deemed appropriate by the compliance monitor to review documentation related to Reliability Standard FAC-003-1. Field audits of ROW vegetation conditions may be conducted if determined to be necessary by the compliance monitor.~~

**2. Violation Severity Levels**

<u>R #</u>	<u>Lower VSL</u>	<u>Moderate VSL</u>	<u>High VSL</u>	<u>Severe VSL</u>
<u>R1</u>	<u>The responsible entity did not include and keep current one of the four required</u>	<u>The responsible entity did not include and keep current two of the four required</u>	<u>The responsible entity did not include and keep current three of the four required</u>	<u>The responsible entity did not include and keep current all required elements of the</u>

	<u>elements of its TVMP, as directed by the requirement.</u>	<u>elements of its TVMP, as directed by the requirement.</u>	<u>elements of its TVMP, as directed by the requirement.</u>	<u>TVMP, as directed by the requirement.</u>
<u>R1.1</u>	<u>N/A</u>	<u>N/A</u>	<u>The applicable entity TVMP did not define a schedule, as directed by the requirement, or the type of ROW vegetation inspections, as directed by the requirement.</u>	<u>The applicable entity TVMP did not define a schedule, as directed by the requirement, nor the type of ROW vegetation inspections, as directed by the requirement.</u>
<u>R1.2</u>	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	<p><u>The responsible entity, in its TVMP, failed to identify and document clearances between vegetation and any overhead, ungrounded supply conductors.</u></p> <p><u>OR</u></p> <p><u>The responsible entity, in its TVMP, failed to take into consideration transmission line voltage, or the effects of ambient temperature on conductor sag under maximum design loading, or the effects of wind velocities on conductor sway.</u></p> <p><u>OR</u></p> <p><u>The responsible entity, in its TVMP, failed to establish Clearance 1 or</u></p>

				<u>Clearance 2 values.</u>
<u>R1.2.1</u>	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	<p><u>The responsible entity failed to determine and document an appropriate clearance distance to be achieved at the time of transmission vegetation management work taking into account local conditions and the expected time frame in which the responsible entity expects to return for future vegetation management work.</u></p> <p><u>OR</u></p> <p><u>The responsible entity documented a Clearance 1 value that was smaller than its Clearance 2 value.</u></p>
<u>R1.2.2</u>	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	<u>The responsible entity failed to determine and document Clearance 2 values taking into account local conditions and the expected time frame in which the responsible entity expects to return for future vegetation management work.</u>
<u>R1.2.2.1</u>	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	<u>Where transmission system transient overvoltage factors were known,</u>

				<u>clearances were not derived from Table 5, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.</u>
<u>R1.2.2.2</u>	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	<u>Where transmission system transient overvoltage factors are known, clearances were not derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.</u>
<u>R1.3</u>	<u>For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, one of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, 5% or less of those persons did not hold appropriate qualifications and training to perform their duties.</u>	<u>For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, two of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 5% up to (and including) 10% of those persons did not hold appropriate qualifications and training to perform their duties.</u>	<u>For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, three of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 10% up to (and including) 15% of those persons did not hold appropriate qualifications and training to perform their duties.</u>	<u>For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, more than three of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 15% of those persons did not hold appropriate qualifications and training to perform their duties.</u>
<u>R1.4</u>	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	<u>The responsible entity's TVMP does not include mitigation</u>

				<u>measures to achieve sufficient clearances where restrictions to the ROW are in effect.</u>
<u>R1.5</u>	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	<u>The responsible entity did not establish or did not document a process for the immediate communication of vegetation conditions that present an imminent threat of line outage, as directed by the requirement.</u>
<u>R2</u>	<u>The responsible entity did not meet one of the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.</u>	<u>The responsible entity did not meet two of the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.</u>	<u>The responsible entity did not meet the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.</u>	<u>The responsible entity does not have an annual plan for vegetation management.</u>  <u>OR</u>  <u>The responsible entity has not implemented the annual plan for vegetation management.</u>
<u>R3</u>	<u>The responsible entity failed to provide a quarterly outage report, but did not experience any reportable outages.</u>  <u>OR</u>  <u>The responsible</u>	<u>The responsible entity provided a quarterly report, but failed to include information required by R3.3.</u>	<u>The responsible entity provided a quarterly outage report, but failed to include a reportable Category 3 outage as described in R3.4.3.</u>	<u>The responsible entity experienced reportable outages but failed to provide a quarterly report.</u>  <u>OR</u>  <u>The responsible entity provided a</u>

	<u>entity provided a quarterly report, but failed to report in the manner specified by one or more of the following subcomponents of Requirement R3: R3.1 or R3.2.</u>			<u>quarterly outage report, but failed to include a reportable Category 1 (as described in R3.4.1) or Category 2 outage (as described in R3.4.2).</u>
R4	N/A	N/A	N/A	N/A

E.

**2.Levels of Non-Compliance**

**2.1.Level 1:-**

- ~~2.1.1.The TVMP was incomplete in one of the requirements specified in any subpart of Requirement 1, or;~~
- ~~2.1.2.Documentation of the annual work plan, as specified in Requirement 2, was incomplete when presented to the Compliance Monitor during an on-site audit, or;~~
- ~~2.1.3.The RRO provided an outage report to NERC that was incomplete and did not contain the information required in Requirement 4.~~

**2.2.Level 2:————**

- ~~2.2.1.The TVMP was incomplete in two of the requirements specified in any subpart of Requirement 1, or;~~
- ~~2.2.2.The Transmission Owner was unable to certify during its annual self-certification that it fully implemented its annual work plan, or documented deviations from, as specified in Requirement 2.~~
- ~~2.2.3.The Transmission Owner reported one Category 2 transmission-vegetation-related outage in a calendar year.~~

**2.3.Level 3:————**

- ~~2.3.1.The Transmission Owner reported one Category 1 or multiple Category 2 transmission-vegetation-related outages in a calendar year, or;~~
- ~~2.3.2.The Transmission Owner did not maintain a set of clearances (Clearance 2), as defined in Requirement 1.2.2, to prevent flashover between vegetation and overhead ungrounded supply conductors, or;~~
- ~~2.3.3.The TVMP was incomplete in three of the requirements specified in any subpart of Requirement 1.~~

**2.4.Level 4:-**

- ~~2.4.1.The Transmission Owner reported more than one Category 1 transmission-vegetation-related outage in a calendar year, or;~~

~~2.4.2. The TVMP was incomplete in four or more of the requirements specified in any subpart of Requirement 1.~~

G.E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
1	TBA	<ol style="list-style-type: none"> <li>1. Added “Standard Development Roadmap.”</li> <li>2. Changed “60” to “Sixty” in section A, 5.2.</li> <li>3. Added “Proposed Effective Date: April 7, 2006” to footer.</li> <li>4. Added “Draft 3: November 17, 2005” to footer.</li> </ol>	01/20/06
<del>X</del>	<del>May 16, 2011</del>	<del>Added requirements for Generator Owner and brought overall standard format up to date</del>	<del>Revision under Project 2010-07</del>

## **Implementation Plan for FAC-003-X – Transmission Vegetation Management Program**

### **Prerequisite Approvals**

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

### **Revision to Sections of Approved Standards and Definitions**

There are no proposed revisions to requirements in other already approved standards. FAC-003-1 will be retired when FAC-003-2 becomes effective.

### **Compliance with Standard**

There are no changes to the requirements applicable to Transmission Owners already in effect in FAC-003-1, and the expectation is that Transmission Owners will maintain their current state of compliance. Thus, the standard is effective for Transmission Owners upon approval, as detailed below.

The proposed changes to FAC-003-1 only address Generator Owner applicability and requirements (add Generator Owner to section 4.3 and add applicable Generator Owner to all requirements). Therefore, this implementation plan only identifies a compliance timeframe for Generator Owners to which this standard will apply.

To reach compliance with the standard, a Generator Owner will have to perform a full review of as-built drawings and determine which generation interconnection Facilities require a Transmission Vegetation Management Plan (TVMP) and inspection as specified by NERC Reliability Standard FAC-003-X. In general, Generator Owners do not have staff that are qualified and experienced to create a TVMP and implement annual plans for vegetation management. Once a complete inventory is created, the Generator Owner will begin the process of gathering information for the TVMP. In instances where the generation interconnection Facilities are owned by a partnership, a majority or operating partner will need to obtain partnership approval to proceed with procurement of a TVMP expert, and later a tree trimming crew. Typically, a request for proposal to hire TVMP consultant is initiated, which could take several weeks in order to obtain sufficient bids (and also satisfy Sarbanes Oxley requirements). Once all bids have been received, a contract with a TVMP consultant is signed. At this point, the TVMP consultant and Generator Owner staff will develop the TVMP, which needs to take into account local growth conditions, types of vegetation and other aspects required by FAC-003-X. Once the TVMP is developed, Generator Owner staff and the TVMP consultant will need to perform a Right-of-Way inspection, usually done using GPS, LIDAR and other tools by experienced and qualified staff.

Once a Right-of-Way inspection is completed and clearances are required, the Generator Owner will need to issue a request for proposal to hire a tree trimming crew that is qualified and experienced to perform required clearance trimming. Once all bids have been received, a contract with a tree trimming crew is signed. When the tree trimming



crew is acquired, the crew will need to familiarize themselves with the entity's TVMP and required clearances. The Generator Owner will typically need to schedule any required outages in order for the tree trimming crew to perform the needed clearance trimming. This action would also include the implementation of the work plan. During scheduled outages, if required, the tree trimming crew will perform any required clearances and document the activities.

Another typical action is the Generator Owner establishing a system for maintaining TVMP-related activities, including maintenance of inspection and clearance documentation. On an ongoing basis, in addition to performing inspections and clearances as required by the entity's TVMP, the Generator Owner will need to ensure that the training and qualification requirements for the standard are met. The entity will also need to maintain documentation of all FAC-003-X activities for compliance period of one year to meet compliance with the standard.

Again, due to a typical lack of experience and qualifications required by FAC-003-X, compliance with this standard by a Generator Owner may take as long as two years – in part because many entities will have generator interconnection Facilities in various parts of the country which may require several instances of TVMP and numerous Right-of-Way inspections.

### **Effective Date**

There are three effective dates associated with this implementation plan:

The first effective date applies to Transmission Owners.

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner become effective upon Board of Trustees' adoption.

The second effective date allows Generator Owners time to prepare a formal transmission vegetation management program as outlined in Requirement R1.

In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The third effective date allows entities time to comply with Requirements R2, R3, and R4.

In those jurisdictions where regulatory approval is required, Requirements R2, R3, and R4 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for is required. In those jurisdictions where no regulatory approval is required, Requirements R2, R3, and R4 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

# Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document

## Introduction

The integrated grid consists of many parts such as power plants, Transmission, and Facilities<sup>1</sup>, some of which are known as generator interconnection Facilities and operate like extension cords to connect generating plants to the overall interconnected grid. Some plants consist of just a single generating unit, other plants consist of multiple generating units, and still others consist of multiple generating units spread over several thousand acres. While not all power plants and their associated Facilities are considered part of the Bulk Electric System (BES)<sup>2</sup>, of concern is how to classify all such generating Facilities, including their generator interconnection Facilities, to ensure that NERC's Reliability Standards provide an appropriate level of reliability for the BES.

When such generator interconnection Facilities are owned by the Generator Owner, are part of the BES, and meet the criteria in the *Statement of Compliance Registry Criteria*, the Project 2010-07—Generator Requirements at the Transmission Interface standard drafting team (drafting team) concludes that such Facilities are only to be included in the reliability standards requirements applicable to the Generator Owner or Generator Operator. To ensure that responsibility for the generator interconnection Facilities is included in all necessary standards, however, a select number of standards need to have Generator Owners added to their applicability.

## Objective

The purpose of Project 2010-07 is to ensure that all generator-owned Facilities are appropriately covered under NERC's Reliability Standards. The drafting team believes it is appropriate to classify various generating Facilities and Elements (sometimes including generator interconnection Facilities) as part of the BES. That does not mean, however, that a Generator Owner or Generator Operator should be required to automatically register as a Transmission Owner or Transmission Operator simply because it owns and/or operates BES Elements or Facilities that are considered by some entities to be Transmission. While Generator Owners and Generator Operators meeting the criteria in the *Statement of Compliance Registry Criteria* own and operate Elements and Facilities that are considered by some entities to be Transmission, these are most often not part of the integrated grid, and as such should not be subject to all of the same standards applicable to Transmission Owners and Transmission Operators who own and operate transmission Elements and Facilities that are part of the integrated grid.

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<sup>1</sup> "Facility" is defined in [NERC's Glossary of Terms](#) as "A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)."

<sup>2</sup> The current definition of "Bulk Electric System" in the [NERC's Glossary of Terms](#) reads: "As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition." The drafting team interprets "electrical generation resources" as inclusive of generator interconnection Facilities. Note that this definition is undergoing significant revision under [Project 2010-17—Definition of Bulk Electric System](#).

When the Elements and Facilities owned and operated by Generator Owners and Generator Operators are considered by some entities to be Transmission and deemed part of the integrated grid, registering the Generator Owner or Generator Operator as a Transmission Owner or Transmission Operator is appropriate. But most often the Facilities are limited to interconnecting generation to the Transmission system and as such have little, if any, measurable effect on the overall reliability of the BES. In fact, registering a Generator Owner or Generator Operator as a Transmission Owner or Transmission Operator may decrease reliability by diverting the Generator Owner's or Generator Operator's attention from the operation of the equipment that actually produces electricity – the generation equipment itself.

The drafting team's goal is to ensure that an adequate level of reliability is maintained in the BES by clearly describing which standards need to be applied to generator interconnection Facilities that are not already applicable to Generator Owners or Generator Operators. This can be accomplished by properly applying selected standards or specific standard requirements to Generator Owners and Generator Operators. The drafting team recommends a plan to modify the requirements and measures of a selected number of standards to make them applicable to appropriate Generator Owners and Generator Operators.

### **Proposed Next Steps and Review of Reliability Standards**

Below, the drafting team outlines its recommendations to clearly identify the appropriate generation Facilities and standards requirements that should apply to such generation Facilities to ensure that the reliability of the BES is maintained:

**FAC-001-0—Facility Connection Requirements** currently applies to Transmission Owners and addresses the need for Transmission Owners to establish Facility connection and performance requirements for interconnection to their Facilities. Because Generator Owners may be requested to allow interconnection to their Facilities, the STD recommends the following:

- Revise FAC-001 so that it applies to a Generator Owner if, and when, it executes an Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility. (See accompanying draft standard FAC-001-1.)
  - In its first posting for informal comment, the drafting team set the “trigger” for the application of FAC-001 as the receipt of a request for interconnection. Many commenters disagreed with this approach and suggested that the “trigger” be based upon “the intent or obligation” to interconnect a new Facility to an existing interconnecting Facility that is owned by a generator. Accordingly, the drafting team has proposed language to address this concern. The intent of this modified language is to start the compliance clock at such time as the Generator Owner executes an Agreement to perform the reliability assessment required in FAC-002-1. This step should occur whether the generator voluntarily agrees to the interconnection request or is compelled by a regulatory body to do so. In either case, we expect the Generator Owner and the requestor to execute some form of Agreement. We intentionally excluded a specific reference to the form of Agreement (such as a feasibility study) in deference to comments that we should avoid comingling of commercial and reliability aspects in reliability standards.

**FAC-003-2—Vegetation Management** currently applies to Transmission Owners and addresses the need to maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission Rights-of-Way (ROW) and minimize encroachments from vegetation located adjacent to the ROW. It has been a major concern that certain types of Facilities used to interconnect generation be required to provide the same level of vegetation management as required for the Transmission Owner operating in the BES. Numerous comments requested a specific length for the interconnecting line before considering application of the standard. The drafting team recommends:

- Revise FAC-003 so that it applies to Generator Owners that own a Facility that extends greater than one half mile beyond the fenced area of the switchyard, generating station or generating substation (up to the point of interconnection with the Transmission system). (See accompanying draft standards FAC-003-X and FAC-003-3.)
  - The drafting team elected to use the half-mile qualifier in its latest proposed changes. The GOTO Ad Hoc Group had originally proposed something similar, but their proposed criterion was a length of “two spans (generally one half mile from the generator property line).” The drafting team elected to use only the half-mile qualifier because it has been supported by industry comment and is clearer than referencing both two spans *and* the half-mile length. This distance is within the Generator Owner’s line of sight and could be visually monitored for vegetation conditions on a routine basis. Beyond the distance of one half mile, a vegetation management program is necessary to manage the Right-of-Way.
  - The drafting team also added text boxes to each proposed standard modification to help define certain terms within the context of the standard, rather than propose defined terms.

At this stage, the drafting team is developing two versions of proposed revisions to FAC-003: one to FAC-003-1, the current FERC-approved version of the standard (labeled FAC-003-X in accompanying documents) and one to FAC-003-2, the proposed version currently under development under Project 2007-07 (the Project 2010-07 team is labeling its revisions as FAC-003-3). See the accompanying proposed redline standards for further justification and detail.

The proposed changes listed above mark a significant decrease in changes originally proposed by the GOTO Ad Hoc Group in its [Final Report](#). The drafting team has again reviewed every reliability standard included in that report, as well as MOD and TPL standards identified in comments it has received. The drafting team does not believe that changes to reliability standards other than FAC-001 and FAC-003 are necessary to close any reliability gaps associated with generator interconnection Facilities that are non-network/non-integrated in nature (typically radial and used solely for the purpose of connecting the generating unit or units to the Transmission Facilities). Below, the drafting team has included its notes about why no other standards require modification as part of this project. The standards highlighted here are those about which questions were raised by commenters or regulatory staff:

- **COM-001-1.1:** This standard applies to entities with a wide-area view. The related responsibilities for Generator Operators are already addressed in COM-002-2.
- **EOP-005-2:** There was some concern that EOP-005 did not properly account for the Generator Operator’s responsibility when it comes to system restoration plans, but EOP-005-

2, R13 (which received regulatory approval on May 23, 2011) requires Generator Operators to have written Blackstart Resource Agreements or mutually agreed upon procedures or protocols with its Transmission Operator. Requirements R14 through R18 require the Generator Operator to develop procedures, test its blackstart generators, and provide related training.

- **MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1a, MOD-030-2:** To apply these standards to Generator Operators would require them to have a wide-area view of the integrated grid and to utilize commercially sensitive information that Generator Operators are currently precluded from viewing or using. In some cases, such as with MOD-001, the standard could only apply if a Generator Operator was registered as a Transmission Service Provider due to an interconnection service request and subsequently adopted an Open Access Transmission Tariff. The drafting team does not believe this is likely, unless ordered by FERC.
- **PER-002-0:** In Order 693, FERC directed NERC to “expand the applicability of the personnel training in Reliability Standard, PER-002-0, to include (i) generator operators centrally-located at a generation control center with a direct impact on the reliable operation of the Bulk-Power System...” In Order 742, the Commission said it is “not modifying the Order No. 693 directive regarding training for certain generator operator dispatch personnel, nor are we expanding a generator operator’s responsibilities.” This issue does not deal with generator interconnection Facilities and is thus outside the scope of Project 2010-07. The directive has been included in NERC’s issues database to be addressed in a future project.
- **PRC-001-1:** Generator Operators are already appropriately accounted for in this standard in requirements 1, 2, 3, and 5.
- **TOP-003-0:** TOP-003-0 already requires the Generator Owner to provide outage information to its Transmission Operator on a daily basis. Proposed TOP-003-2 R4 continues to make this responsibility clear by requiring Generator Owners and Generator Operators to satisfy the obligations of the Transmission Owner’s and Transmission Operator’s data specification plan.
- **TOP-006-2:** TOP-006-2 deals with general issues with generator reporting. Though not explicitly stated, Requirement R2 requires reporting of scheduled outages of equipment such as voltage regulators, shunt capacitors, etc. The drafting team believes that Elements associated with a generator interconnection Facility are to be reported under this requirement
- **VAR-001-1:** This standard also requires a wide-area view that is inappropriate for a Generator Operator. Generator Operators, for instance, should never be setting voltage schedules.
- **VAR-002-1.1b:** The drafting team received some comments expressing concern about capacitors under operational control of the Generator Operator. Requirement R3.2 requires notification for status or capability change on any other Reactive Power resources under the Generator Operator’s control and the expected duration of the change in status or capability. The drafting team believes that capacitors are included in this requirement.

The drafting team also decided not to propose new defined terms in the NERC Glossary, but has met with NERC and FERC staffs, regional compliance managers and industry organizations to discuss possible solutions to the issue of concern to most Generator Owners and Generator Operators – registration as Transmission Owners and Transmission Operators. The drafting team believes this issue has the attention of appropriate NERC and regional staffs and has volunteered to provide assistance in those groups’ efforts to address them. While these changes are not within the explicit

scope of the drafting team, the goal is to work with NERC and regional compliance enforcement and compliance registration staffs to develop a comprehensive package that will address all reliability gaps – whether real or perceived – so that entities are appropriately registered and the appropriate reliability standards are applied to those entities.

The drafting team acknowledges that there may be Elements and Facilities that are not radial or used solely for the purpose of connecting the generating unit(s) to Transmission Facilities. It is outside the scope of the drafting team to address this as part of its project, but it believes that the best way to address these non-radial Facilities is through changes to the criteria in the *Statement of Compliance Registry Criteria* as they apply to Generator Owner or Generator Operator. Trying to apply simple ‘bright line’ criteria to such Facilities as a drafting team would be a daunting task, as the configuration of interconnections is not consistent continent-wide, nor are all adjacent Elements and Facilities similar. Addressing these non-radial generator interconnection Facilities will require individual evaluations to ensure that no reliability gaps exist, and this is a task best suited to compliance staffs.

The drafting team also acknowledges that, if another party interconnects to a Facility owned by a Generator Owner, there may be the need to address MOD or TPL standards. However, the drafting team believes that this, too, is best handled through specific evaluation, perhaps accompanied by changes to the compliance registry. Entities that face this kind of scenario may also meet criteria applicable to other registrations such as Transmission Service Provider or Transmission Planner.

### **Other Solutions**

Because the efforts outlined here will likely not take effect for a year or more, Generator Owners and Generator Operators that are concerned about their registration status should explore options like those explained below and in further detail in NERC Compliance Bulletin 2010-004.

On April 20, 2010, NERC Compliance published a [Public Bulletin](#) to provide guidance for situations like this, in which entities delegate reliability tasks to a third-party entity. In this bulletin, NERC Compliance emphasizes that while a registered entity may not delegate its responsibility for ensuring that a task is completed, it may delegate the performance of a task to another entity.

As is explained in the bulletin, compliance responsibility for applicable NERC Reliability Standard requirements and accountability for violations thereof may be achieved through several means, including the following:

**1. By Individual:** an entity is registered on the NERC Compliance Registry and such registered entity assumes full compliance responsibility and accountability; or

**2. By Written Contract:** parties enter into written agreement whereby:

a. A registered entity delegates the performance of some or all functional activities to a third party that is not a registered entity, and the registered entity retains full compliance responsibility and violation accountability; or

b. A registered entity delegates the performance of some or all of the functional activities to a third party, and the third party accepts full compliance responsibility for the specific functions it performs and violation accountability. In this case, there may be individual, concurrent or joint registration of

the entities, depending on the nature of the contractual relationship and, in any event, only the registered entity would be held responsible or accountable by a Regional Entity or NERC; or

**3. By Joint Registration Organization (JRO):** each party is registered and is required to clearly identify and allocate compliance responsibility and violation accountability for their respective functions under applicable NERC Reliability Standard requirements.



# Unofficial Comment Form for Project 2010-07—Generator Requirements at the Transmission Interface

Please **DO NOT** use this form to submit comments. Please use the electronic comment form located at the link below to submit comments on the first formal posting for Project 2010-07—Generator Requirements at the Transmission Interface. The electronic comment form must be completed by **July 17, 2011**.

[Project 2010-07—Generator Requirements at the Transmission Interface](#)

If you have questions please contact Mallory Huggins at [mallory.huggins@nerc.net](mailto:mallory.huggins@nerc.net) or 202-383-2629.

This is the first 30-day formal comment period for the standards included in Project 2010-07. A 30-day informal comment period took place earlier this year, from March 4 to April 4, 2011. The team thanks all those who provided feedback during that comment period. The team has reviewed and considered all comments submitted, and has incorporated many of them into its latest proposed standards, as explained in the [Summary Response to Informal Comment](#) posted at the Project 2010-07 project page.

The purpose of Project 2010-07 is to ensure that all generator-owned Facilities are appropriately covered under NERC's Reliability Standards. While many Generator Owners and Generator Operators operate Elements and Facilities that are considered by some entities to be Transmission, these are most often radial Facilities that are not part of the integrated grid, and as such should not be subject to the same standards applicable to Transmission Owners and Transmission Operators who own and operate Transmission Elements and Facilities that are part of the integrated grid.

As part of the BES, generators affect the overall reliability of the BES. However, registering a Generator Owner or Generator Operator as a Transmission Owner or Transmission Operator, as has been the solution in some cases in the past, may decrease reliability by diverting the Generator Owner's or Generator Operator's resources from the operation of the equipment that actually produces electricity – the generation equipment itself.

The drafting team's goal is to ensure that an adequate level of reliability is maintained in the BES by clearly describing which standards need to be applied to generator interconnection Facilities that are not already applicable to Generator Owners or Generator Operators. This can be accomplished by properly applying FAC-001 and FAC-003 to Generator Owners as proposed in the redline standards posted for comment.

Before reviewing the standards, the drafting team encourages all stakeholders to read the [background resource document](#) it has provided to describe its rationale and its work thus far.

**You do not have to answer all questions. Enter all comments in Simple Text Format.**

1. Do you support the proposed redline changes to FAC-001-1?

Yes

No

Comments:

2. Do you support the one year compliance timeframe for Generator Owners as proposed in the Implementation Plan for FAC-001-1?

Yes

No

Comments:

3. Taking into consideration that only one of the versions of FAC-003 will actually be implemented, a decision that will be made as the Project 2010-07 drafting team learns more about the status of Project 2007-07—Vegetation Management, do you support the proposed redline changes to FAC-003-X and FAC-003-3?

Yes

No

Comments:

4. The drafting team has added Generator Owners to the Applicability sections of FAC-003-X and FAC-003-3 with the qualifier that the included lines “extend greater than one half mile beyond the fenced area of the switchyard, generating station or generating substation up to the point of interconnection with the Transmission system.” The team received many comments about the need to define a distance rather than other measures for exclusion, and decided on the one half mile as a reasonable distance. Do you agree with this half-mile qualifier?

Yes

No

Comments:

5. Do you support the two year compliance timeframe for Generator Owners as included and explained in the Implementation Plans for FAC-003-X and FAC-003-3?

Yes

No

Comments:

6. In its background resource document, the drafting team lists the standards that it has not modified, and offers rationale for its decisions. Are there any reliability standards or requirements that you believe should apply to Generator Owners or Generator Operators that own and are responsible for the operation of an overhead Facility, that are not already applicable or have been proposed to be applicable (FAC-001 and FAC-003) by

the Project 2010-07 drafting team? If so, please list them and offer an explanation as to why they should be applicable to that entity.

Yes

No

Comments:

7. Do you have any other questions or concerns with the proposed standards or with the background resource document that have not been addressed? If yes, please explain.

Yes

No

Comments:



NORTH AMERICAN ELECTRIC  
RELIABILITY CORPORATION

## Standards Announcement

### Project 2010-07 Generator Requirements at the Transmission Interface Formal Comment Period Open June 17 – July 17, 2011

**Now available at:** [http://www.nerc.com/filez/standards/Project2010-07\\_GOTO\\_Project.html](http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html)

The Generator Requirements at the Transmission Interface standard drafting team has posted proposed modifications to FAC-001 and FAC-003, along with a background resource document, for a formal comment period. For FAC-003, the team has posted proposed changes to two versions of the standard: FAC-003-1, the current FERC-approved version of the standard, has been modified as FAC-003-X, and FAC-003-2, the version currently under development by the Project 2007-07 —Vegetation Management drafting team has been modified as FAC-003-3. The 30-day formal comment period will end at **8 p.m. Eastern on Sunday, July 17, 2011.**

#### Instructions for Commenting

Please use this [electronic form](#) to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at [monica.benson@nerc.net](mailto:monica.benson@nerc.net). An off-line, unofficial copy of the comment form is posted on the project page:

[http://www.nerc.com/filez/standards/Project2010-07\\_GOTO\\_Project.html](http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html)

#### Next Steps

The drafting team will consider all comments submitted and make revisions to the draft standards to address issues identified by commenters. The team will submit its work for quality review, and following the quality review, the team's consideration of comments will be posted, along with the revised standards, associated implementation plans, and supporting documents. The standards will then be posted for a 45-day formal comment period with an initial ballot conducted during the last 10 days of the comment period.

#### Background

This is the first 30-day formal comment period for the standards included in Project 2010-07. A 30-day informal comment period took place earlier this year, from March 4 to April 4, 2011. The team thanks all those who provided feedback during that comment period. The team has reviewed and considered all comments submitted, and has incorporated many of them into its latest proposed standards, as explained in the [Summary Response to Informal Comment](#) posted at the Project 2010-07 project page.

The purpose of Project 2010-07 is to ensure that all generator-owned Facilities are appropriately covered under NERC's Reliability Standards. While many Generator Owners and Generator Operators operate Elements and Facilities that are considered by some entities to be Transmission, these are most often radial Facilities that are not part of the integrated grid, and as such should not be subject to the same standards applicable to Transmission Owners and Transmission Operators who own and operate Transmission Elements and Facilities that are part of the integrated grid.

As part of the BES, generators affect the overall reliability of the BES. However, registering a Generator

Owner or Generator Operator as a Transmission Owner or Transmission Operator, as has been the solution in some cases in the past, may decrease reliability by diverting the Generator Owner's or Generator Operator's resources from the operation of the equipment that actually produces electricity – the generation equipment itself.

The drafting team's goal is to ensure that an adequate level of reliability is maintained in the BES by clearly describing which standards need to be applied to generator interconnection Facilities that are not already applicable to Generator Owners or Generator Operators. This can be accomplished by properly applying FAC-001 and FAC-003 to Generator Owners as proposed in the redline standards posted for comment.

Before reviewing the standards, the drafting team encourages all stakeholders to read the [background resource document](#) it has provided to describe its rationale and its work thus far.

Additional information is available on the project page at [http://www.nerc.com/filez/standards/Project2010-07\\_GOTO\\_Project.html](http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html)

### **Standards Process**

The [Standard Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

*For more information or assistance, please contact Monica Benson,  
Standards Process Administrator, at [monica.benson@nerc.net](mailto:monica.benson@nerc.net) or at 404-446-2560.*

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**Individual or group. (41 Responses)**  
**Name (24 Responses)**  
**Organization (24 Responses)**  
**Group Name (17 Responses)**  
**Lead Contact (17 Responses)**  
**Question 1 (37 Responses)**  
**Question 1 Comments (41 Responses)**  
**Question 2 (35 Responses)**  
**Question 2 Comments (41 Responses)**  
**Question 3 (36 Responses)**  
**Question 3 Comments (41 Responses)**  
**Question 4 (37 Responses)**  
**Question 4 Comments (41 Responses)**  
**Question 5 (36 Responses)**  
**Question 5 Comments (41 Responses)**  
**Question 6 (36 Responses)**  
**Question 6 Comments (41 Responses)**  
**Question 7 (36 Responses)**  
**Question 7 Comments (41 Responses)**

Group
Bonneville Power Administration
Chris Higgins
Yes
Yes
Yes
No
BPA believes that there needs to be a clear demarcation where Transmission Owner and Generator Owner responsibilities begin and end.
Yes
Yes
No
Group
Notheast Power Coordinating Council
Guy Zito
Yes
Yes
No
See comments in the following questions.
No
The qualifier should be similar to that specified in Part 4.2.4 of FAC-003-3: "This standard applies to overhead transmission lines identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is

crossing the substation fence. " Vegetation needing attention can exist within a half mile of a switchyard. Vegetation does not discriminate between Generation and Transmission Owners.
Yes
Yes
Regarding the Right-of-Way definitions, the definition in FAC-003-3 is the better of the two. Suggest adding "and maintain" to the first sentence of the definition as follows: The corridor of land under a transmission line(s) needed to operate and maintain the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria. The term Right-of-Way goes beyond Transmission Vegetation Management, and that should be considered in the definition. How does Right-of-Way affect transmission facilities that are routed over bodies of water, or over valleys, highways, etc.? Right-of-Way in relation to underground facilities? The format of FAC-003-X should be made consistent with current NERC guidelines (i.e.--Parts of Requirements should not have R's in their numbering, should be 1.1, 1.2 etc.).
Individual
Mike Laney
Luminant Power
Yes
Yes
Yes
Yes
Yes
No
No
Group
SERC OC Standards Review Group
Gerald Beckerle
Yes
Consider a better definition of what constitutes an "applicable" generator owner or point to the document that explains the definition.
No
We feel that an 18 month implementation plan would be more conducive for generators to meet these new requirements
Yes
Yes
While we agree, we believe that a better explanation of "the fenced area of the switchyard, generating station or generating substation up to the point of interconnection with the Transmission system" should be included. One suggestion is to distinguish between a plant perimeter fence and an internal switchyard fence.

Yes
No
No
Group
EPSA
Jack Cashin
<p>Background The Electric Power Supply Association (EPSA) endorsed the initial recommendations of the Ad Hoc Group for Generator Requirements at the Transmission Interface, offered informal comments on the March 2011 White Paper Proposal for Project 2010-07 and now appreciates this opportunity to provide comments on the questions posted June 17, 2011. Since NERC’s creation of the “GOTO Team” in February of 2009, EPSA has supported the efforts of Ad-Hoc Group and now the Project 2010-07 Standards Drafting Team (SDT). While EPSA members’ compliance registration includes several functional entity types, the bulk of competitive suppliers’ registrations are as Generator Owners (GOs) and Generator Operators (GOPs). EPSA applauds the SDT’s decision to recommend the use the “intent of obligation” as the reason for application of FAC-001 rather than the receipt of request for interconnection and thereby supports the revisions to FAC-001-1. The proposed modification to FAC-001 (a new R2) would require a GO to develop “Facility connection requirements” within “45 days of executing an Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility...” The use of the agreement execution is a more reasonable triggering mechanism for FAC-001 application and compliance. The SDT’s recommendation intentionally excluded specific reference to the form of agreement to avoid commingling commercial and reliability aspects in reliability standards. However, the existing language may still may mix commercial and reliability issues. The accompanying project Background Resource Document (p.2) makes it clear that the interconnection to an existing generator facility is contemplated to be the “existing interconnecting Facility that is owned by a generator” – that is, the generator’s lead. The generator’s leads are considered part of the “existing generator Facility,” however, the generator, step-up transformer and other equipment that is within the generator switchyard can also be considered part of the Facility. FERC requires all transmission facilities to be available for “open access.” A generator lead would become open access if another customer interconnected to it. Therefore FAC-001-1 could be made clearer by modifying the language regarding the 45-day trigger as follows: within “45 days of executing an Agreement to evaluate the reliability impact of interconnecting another Facility to its the Generator Owner’s existing generation interconnecting transmission Facilities...” This modification would make it clear that the requirement does not apply to an entity that wants to, for example, connect a new generator within the fenced-in site of the existing generator, but instead only applies to request to interconnect to the generator lead.</p>
Yes
Yes
<p>EPSA generally supports the SDT’s proposed redline changes to FAC-003-X and FAC-003-3 and SDT’s diligence in monitoring Project 2007-07. There is one distinction however that EPSA would like to bring to the SDT’s attention that could increase clarity. FAC-003-X and FAC-003-3 both have similar “one half mile” language, but the starting point for the one half mile can occur one of three ways. In FAC-003-X, the language in 4.3.1 reads “Generator Owner that owns an overhead Facility that extends greater than one half mile beyond the fenced area of the switchyard, generating station or generating substation up to the point of interconnection with the Transmission system and ...” Therefore, there are three possible starting points for the measurement of the one half mile: beyond the fenced area of (i) the switchyard, (ii) the generating station, or (iii) the generation substation. While it would appear implicit that GO’s would determine which of the three was used to make the determination that the GO determines the starting point. Another point for consideration is that a Generator Owner’s overhead Facility that is within the fence should explicitly not be applicable to the standard. EPSA believes the language that refers to the “interconnection with the Transmission system” should be changed to “interconnection with a Transmission Owner’s Facility. The reason is</p>



that the term "Transmission" which is defined in the NERC Glossary could be construed to include all of a Generator Owner's interconnection leads. Therefore, we suggest that the language in 4.3.1 be modified as follows to make all of these points clear: A Generator Owner that owns an overhead Facility that extends greater than one half mile beyond the fenced area of either the generator switchyard, generating station or generating substation (as specified by the Generation Owner) up to the point of interconnection with the Transmission Owner's Facility and is operated 200 kV and above and any lower voltage lines designated by the RE as critical to the reliability of the electric system within the region is applicable to this standard."

Yes

EPSA appreciates the SDT proposing to use the approach that provides a specific distance for determining which GO Facility lead lines that FAC-003 should apply to. EPSA agrees that the half-mile qualifier provides a discrete parameter that will limit ambiguity in the Standard.

Yes

No

Yes

EPSA can appreciate the SDT's decision that it not propose new defined terms for the NERC Glossary. The SDT bases the decision on outreach meetings with NERC, regional compliance managers and industry organizations. EPSA supports outreach but still believes that the SDT should propose definitions for the NERC Glossary. The definitions can serve as a basis for the outreach meetings while also further limiting reliability gaps – real or perceived. Much as EPSA expressed in its White Paper comments there is still a need for a definition for generator interconnection facilities. In addition, because integrated transmission facility has also played a big part in the cases that have prompted the need for Project 2010-07 the drafting team should propose a glossary change for that definition as well. A definition for generation interconnection facilities is necessary in Project 2010-07 Standard so that the interface between generators and transmission system can be clearly established and any ambiguities about reliability responsibilities for GOs & GOPs and TO & TOPs can be eliminated. EPSA recommended the definitions from the Ad-Hoc Group Report could be used for incorporating the Generator Interconnection Facility into the standard: Generator Interconnection Facility Sole-use facility for the purpose of connecting the generating unit(s) to the transmission grid. In this regard, the sole-use facility only transmits power associated with the interconnecting generator, whether delivered to the grid or delivered to the generator for station service or auxiliary load, or delivered to meet cogeneration load requirements. Generator Interconnection Operational Interface Location at which operating responsibility for the Generator Interconnection Facility changes between the Transmission Operator and the Generator Operator. These definitions were developed with due consideration for varying configurations, outages, and generators materiality to the BES. The Facility definition defines the purpose of the facility, while the Generator Interconnection Operational Interface definition provides the functional lines of demarcation between the GO and the TO. The definitions were developed based on the purpose of generator interconnection facilities, their usage and how their usage differs from transmission facilities that comprise the interconnected grid. Similar to EPSA's assertions on the White Paper competitive suppliers believe this is a sound basis for distinguishing BES facilities. EPSA also suggests that the SDT include the following proposed definition for Integrated Transmission Facilities for inclusion in the NERC Glossary: Integrated Transmission Facilities (ITF) ITF are the Facilities that are a subpart of Transmission system that are capable of carrying the flows from multiple generator plants at different points of interconnection for delivery to customers, or to other electric systems. This proposed ITF definition builds upon Commission precedent in the Open Access Transmission Tariff (OATT) area. FERC has recognized that facilities that can carry flows from multiple supply points and deliver that power to either customers or other electric systems are proper facilities to include in an OATT and define the "Transmission System" for OATT purposes. The term "Transmission System" is an OATT-defined term that means "The facilities owned, controlled or operated by the Transmission Provider that are used to provide transmission service under Part II [Point-to-Point Transmission Service] and Part III [Network Integrated Transmission Service] of the Tariff." Under Commission precedent, facilities such as generator step-up transformers and generator interconnecting transmission facilities have been excluded from the OATT; i.e., they are not facilities that provide Transmission Service because they cannot carry the

flows from multiple supply points for delivery to customers or other electric system – their only use is to the GO and perform two functions: 1. They deliver power from the GO’s generators at a site to the OATT-defined Transmission System, and 2. They deliver off-site power from the OATT-defined Transmission System to the generators at a site when the generators at a site are not operating. While building on FERC OATT precedent, the proposed definition of “Integrated Transmission Facilities” does not require an applicable Transmission Service tariff to identify those facilities. Integrated Transmission Facilities are simply defined as those that capable of carrying flows from multiple supply points for delivery to customers or to other electric systems. Using the ITF definition, the definition of Generation Owner could be modified as follows: Generation Owner The Entity that owns and maintains generating units but which does not own or maintain Integrated Transmission Facilities. EPSA encourages the Project 2010-07 SDT to consider fitting the above definitions into the current proposal for inclusion in the NERC Glossary. Therefore, EPSA respectfully requests that the SDT for Project 2010-07 consider the all the recommendations made herein to the seven questions.

Individual

Thad Ness

American Electric Power

No

There are substantial reliability issues, as well as additional regulatory, tariff, coordination, and generator and interconnection facility issues, which need to be dealt with before AEP could agree to such requirements. It is not clear that a generator can receive a request for interconnection. We recommend adding qualifier text which states the standard only applies \*if\* an entity plans to allow such a requested interconnection. This would allow an entity to document that they do not plan to allow such interconnections.

Yes

Yes

Yes

Yes

Yes

No

Individual

Edward Cambridge

APS

No

Do not agree with adding GO to FAC-001-1

No

Leave the GO out of the standard.

No

Leave the GO out of both Standards proposed.

No

Leave GOs out of the standards.

No

Leave GOs out of the standards.

No

Leave GOs and GOPs out of the FAC-001 and FAC-003 standards.

Yes

Leave GOs out of the standards.because it just adds more regulation and reporting requirements not

needed.
Individual
Gretchen Schott
BP Wind Energy North America Inc.
Yes
Yes
Yes
Yes
Yes
No
No
Group
PacifiCorp
Sandra Shaffer
Yes
Yes
Yes
Yes
Yes
No
Yes
PacifiCorp believes the Standards Drafting Team should clarify the Transmission Owner and/or the Generator Owner are not required to provide evidence, documentation, notification, or inspection of vegetation management for facilities not owned by the Transmission Owner and/or the Generator Owner.
Individual
Katy Mirr
Sempra Generation
Yes
Sempra Generation supports the proposal for the compliance obligations under R2 associated with an interconnection request not to be triggered until an interconnection study agreement has been executed.
Yes
Yes

Yes
Yes
No
No, Sempra Generation believes the Project 2010-07 Team has effectively indentified the Standards and Requirements that should apply to Generator Owners or Generator Operators that own, and are responsible for, the operation of an overhead Facility, that are not already applicable or have been proposed to be applicable.
Yes
When implemented, the recommendations of the Project 2010-07 Team go a long way toward providing the regulatory and compliance certainty needed by generators who own or operate Generator Interconnection Facilities. NERC is encouraged to provide these industry-supported amendments to the NERC Board of Trustees in the near future. Sempra Generation also supports the comments, being concurrently filed, of the Electric Power Supply Association (EPSA).
Individual
Brian Evans-Mongeon
Utility Services, Inc.
Yes
In one of the supporting documents for the upcoming comments, the GO/TO group included the following statement in support for the rationale on FAC-001. In its first posting for informal comment, the drafting team set the "trigger" for the application of FAC-001 as the receipt of a request for interconnection. Many commenters disagreed with this approach and suggested that the "trigger" be based upon "the intent or obligation" to interconnect a new Facility to an existing interconnecting Facility that is owned by a generator. Accordingly, the drafting team has proposed language to addresses this concern. The intent of this modified language is to start the compliance clock at such time as the Generator Owner executes an Agreement to perform the reliability assessment required in FAC-002-1. This step should occur whether the generator voluntarily agrees to the interconnection request or is compelled by a regulatory body to do so. In either case, we expect the Generator Owner and the requestor to execute some form of Agreement. We intentionally excluded a specific reference to the form of Agreement (such as a feasibility study) in deference to comments that we should avoid comingling of commercial and reliability aspects in reliability standards. I wonder about whether or not this can work timing-wise. It says the compliance clock starts with the agreement to perform the reliability assessment for FAC-002. The FAC-001 requirements outline the need for a registered entity to document, maintain, and publish facility connections requirements in order to be compliant. If the clock starts at the agreement for the assessment, does that mean that you then document, maintain, and publish the connection requirements? Don't the connection requirements usually outline the terms for the "agreement for the assessment"? I am not sure that I understand the timing sequence in order to be compliant to the standard. I would think that the agreement needs to be in place at the time of the effective date of the standard, not upon an application.
Individual
Samuel Reed
Tri-State Generation and Transmission, Inc.
Yes
Yes

Yes
Yes
Yes
No
No
Individual
Alice Ireland
Xcel Energy
Yes
We believe it would be helpful to put explanatory wording in that if an entity is already registered as a Transmission Owner and Generator Owner, the Generator Owner portion of that entity would not have to have a separate set of interconnection requirements.
Yes
Yes
Yes
Yes
No
No
Group
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)
Carol Gerou
No
In general, the NSRF supports the changes to FAC-001-1. However the 45 days to execute an agreement would be a significant burden on a Generator Operator that does not have an existing process in place. The NSRF believes an aggressive but realistic time frame is 120 days. This would allow sufficient time to develop the procedure and obtain the necessary technical and legal reviews. Please clarify why "Protection" is capitalized in section 3.1.5. "Protection System" is defined by NERC but "System Protection" is not. Recommend the "half mile" statement be included within the Applicability section of this Standard as it stated in FAC-003-X.
Yes
Yes
Yes
Although the NSRF agrees with the 1/2 mile criteria (see question 1); we believe the drafting team will have to develop additional justification for this criteria given FERC's recent orders, RC11-1 and RC11-2 (see question 6 for full FERC Order details). In these orders FERC "implies" that if the GO/GOP is responsible for a breaker operated at 100kV or higher the entity should be required to register as a TOP/TO. Therefore it appears FERC would not be inclined to provide any leeway based

on distance from the substation. The SDT should note that the FERC Order points to this Project to "address matters involving reliability obligations at the interface of the transmission grid", which is foot note 58.

Yes

Yes

In FERC order "Denying Appeals of Electric Reliability Organization Registration Determinations" dated June 16, 2011 (RC11-1 and RC11-2) FERC explicitly stated compliance GAPS existed with the following standards at a minimum: • FAC-011, Requirements R2, R2.1, R2.2. • PRC-001-1, Requirements R2, R2.2, R4; • PRC-004-1 Requirement R1; • TOP-004-2, Requirements R6, R6.1, R6.2, R6.3, R6.4; • PER-003-1, Requirements R1, R1.1, R1.2; • FAC-003-1, Requirements R1, R2; • TOP-001, Requirement R1 and • FAC-014-2, Requirement R2. When a GO/GOP owns transmission equipment but is not registered as a TO or TOP. The drafting team should explicitly address each of these the above requirements.

No

Individual

Jody Nelson

Georgia Transmission Corporation

Yes

We commend the drafting team for their efforts to address gaps in Facility Connection Requirements. We believe that the requirements under R3 should be limited to Generator owned equipment to avoid duplication of efforts. A Generator Owner receiving an interconnection request is required to submit an interconnection request to the Transmission Owner which in turn would study the impact of such a request on the Transmission System. Therefore there is no gap as far as the Integrated Transmission System that the third party is interconnecting to through the Generator Owner. However, Generator Owners are responsible for verifying that their equipment is capable of accommodating the interconnection request.

Yes

Yes

Yes

No

No

Individual

Bill Rees

BGE

Yes

This change closes the gap in areas not already covered under FAC-003-1 in a continuous improvement effort to ensure vegetation-related transmission reliability for applicable lines.

Yes

This requirement is consistent with the initial time frame when FAC-003-1 was first implemented.

Yes

As noted in Question-1 above.

Yes

1/2 mile is a distance that can generally be viewed from one location. e.g. the switchyard. and can be

construed to present minimal risk since switchyards have a reasonably frequent personnel presence that could be expected to notice vegetation issues in the <1/2 mile area.

Yes

No comment.

No

No comment.

No

No comment.

Group

Electric Market Policy

Connie Lowe

Yes

Yes

Yes

Yes

Yes

No

No

Group

SERC Planning Standards Subcommittee

Charles W. Long

Yes

Yes

Yes

Yes

However, we are concerned that there may be a reliability gap for locations where there is not a half-mile line-of-sight from the generation switchyard.

Yes

No

No

The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.

Group

Arizona Public Service Company

Janet Smith, Regulatory Affairs Supervisor

Yes

These comments supersede the previous comments submitted by Arizona Public Service Company on July 7, 2011.

Yes

Yes

No

The generator should be responsible no matter the length from fence area to the point of interconnection.

No

The generator should be able to be in compliance within one year since the distance of line miles is small.

No

No

Individual

John Bee

Exelom

No

Exelon does not agree that this standard should be broadly applied to a GO. GOs who do not own a switchyard and whose point of interconnection is a disconnect switch associated with the generator leads prior to the switchyard should be excluded from this standard. If a group of GOs share a generator tie line, then the associated Interconnect Agreement that each of the GO has with the applicable TO and/or TOP should address how these shared connections will effect the system. GOs may not have the resources or expertise to conduct the required interconnect studies to meet this standard

Yes

Yes

Yes

No

Yes

FAC-001 1. Exelon has generating stations that have the Main Power Transformer (MPT) disconnect as the point of demarcation. The station owns the short leads from the MPT disconnect back to the generator and the applicable TO owns from the MPT disconnect up to and including the switchyard. It is not practical for another entity to request to interconnect to the MPT disconnect nor should it be allowed. The SDT should consider verbiage to the standard that does not allow requests to interconnect to a MPT disconnect. 2. Exelon is having difficulty determining how this standard would apply to GOs and how GOs would implement the standard; suggest that examples be provided in an implementation document specifically showing where and how this standard would apply.

Group

Imperial Irrigation District (IID)

Jesus Sammy Alcaraz

Yes

Yes



Yes
Yes
Yes
No
No
Individual
Michelle D'Antuono
Ingleside Cogeneration LP
Yes
However, there may need to be a variance for ERCOT because the Power Generating Companies in ERCOT are not allowed to own transmission assets.
No
: As drafted, the document still refers to generation interconnection lines as transmission lines in critical places. We understand that the SDT has taken significant steps to minimize this in both FAC-001 and FAC-003 and has had discussions with NERC about not registering GOs as TOs; however, this lack of distinction between high voltage generation interconnection lines and actual transmission lines still presents a difficult situation for Generations Owners and a source of contention with Reliability Entities. This could be resolved somewhat by using the non-defined term "generation interconnection lines" in place of "transmission lines" in, for example, section 4.3.1. Since the term "transmission line" is also undefined, this would seem to be a reasonable approach.
No
Ingleside Cogeneration LP believes there should be a relaxation in the vegetation management requirements for those interconnections which only serve as a radial link to the BES. Although we fully understand the importance of keeping vegetation away from high voltage lines, the one year period is much too frequent in our generator locations. The added documentation and other expenses simply do not justify the non-existent gain in reliability when vegetation in a locale (e.g.; desert) never reaches five feet above the ground. Consider limiting this exception to units below a certain MVA rating that are not critical to the BES – perhaps coupled with evidence that vegetative intrusions are highly unlikely.
No
The SDT needs to clarify that the one-half mile distance is measured from the property line of the Generation Owner, i.e., an interconnection line that is in a ROW. In addition, the half mile qualifier makes sense only for those interconnections into critical generation facilities. See our response under Question #3.
No
The two year compliance time frame makes sense only for those GOs who own interconnections into critical generation facilities. See our response under Question #3.
No
Yes
There is a fundamental issue related to the interconnection of generation and distribution facilities into the transmission grid. There is a myriad of complex architectures which make the designation of ownership and operational responsibilities unclear in both cases. Both this team's efforts and those by the project team redefining the extent of the BES have run into this issue. Ingleside Cogeneration LP recognizes that the effort to properly assign reliability responsibilities in these gray-area connections is difficult. However, pushing the issue back to the GO/GOP by looking for them to jointly determine

responsibilities with adjacent entities will create every conceivable arrangement possible. It seems like it should be possible to address a handful of common interconnection configurations at the start. As knowledge builds, perhaps other architectures could be added. This seems to be the direction that the project team redefining the extent of the BES is heading. Lastly, we need some assurance that regulators will work with us as we go down this path. Right now, the feeling is that they will continue to use forced registrations as a hammer – which may render moot this team’s efforts anyways.

Group  
LG&E and KU Energy  
Brent Ingebrigtsen

Yes  
Although the “one half mile” is much clearer than “two spans”, what is the rationale for choosing ½ mile as opposed to another length such as 1 or 2 miles?

Individual  
Dale Fredrickson  
Wisconsin Electric

No  
In addition to the "greater than one-half mile" criteria, we maintain there should also be an exclusion for lines up to one mile in length which are entirely on the Generator Owner's property.

Yes  
No  
No

Individual  
Keith Morisette  
Tacoma Power  
Yes  
Yes

Yes  
Tacoma Power suggests that three standards be reconsidered for inclusion in this Project, to include the Generator Owner and/or Operator: EOP-005, more directly responsible for participation in restoration plans; PER-002, responsible for training; and VAR-001.

Individual  
Joe Petaski

Manitoba Hydro
No
The Applicable Entities now include a Generator Owner that meets the following condition: 'Generator Owner with an executed Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility' A Generator Owner should not have such power. In many instances Generator Owners do not have the models or expertise to perform interconnection studies to determine if there is an impact on the Transmission Network. All interconnection requests should be implemented by the Transmission Owner (TO) regardless if the interconnection point is within a Generation Owner facility or End-User facility. The TO is in the best position to set unbiased connection requirements to ensure the reliability of the BES is maintained. If a mechanism is created to allow interconnection to a BES line owned by Generator Owner, then it is essential for this Generator Owner providing this interconnection service to be a TO to ensure all reliability standards, including the protection standards, are met so the reliability of the BES is maintained. The drafting team should demonstrate where this situation is occurring. If the redline changes are implemented, could Generator Owner #1 permit Generator Owner #2 to interconnect one of their generators within Generator Owner #1's Facility? Would Generator Owner #2 then need to have an executed Agreement to permit further generator interconnection? From a Transmission Owner viewpoint, it is tough enough to coordinate generator connection queues among adjacent TOs. Having to coordinate with Generator Owners as well would greatly increase the complexity of coordination.
No
See question #1 comments. We do not support changing the applicability of FAC-001-1 to include Generator Owners 'with an executed Agreement' or Generator Owners that own BES transmission.
No
The direction of the background resource document gives special treatment to the Generator Owner in that it allows the Generator Owner TO status for a couple of standards (FAC-001 and FAC-003), but exempts the Generator Owner from many of the standards applicable to a TO. The NERC Functional Model defines the various functional entities. If a Generator Owner wants to be a TO, all the Requirements applicable to a TO should apply. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions.
Yes
The direction of the background resource document gives special treatment to the Generator Owner in that it allows the Generator Owner TO status for a couple of standards (FAC-001 and FAC-003), but exempts the Generator Owner from many of the standards applicable to a TO. A Generator Owner that owns BES transmission should be held accountable for the specific Requirements and Reliability Standards applicable to the TO and Transmission Operator functions. If no other entity assumes accountability for these specific Requirements and Reliability Standards on the Generator Owner BES transmission (for example system operation, protection and communication), there will be a reliability gap. Improper operation, coordination and protection of the Generator Owner BES transmission could have an impact on reliability.
Individual
Greg Rowland
Duke Energy
Yes
Yes
Yes
Yes

Yes
No
No
Group
Public Service Enterprise Group
John Seelke
No
The language in R2 needs to be clarified with regards to the term "its existing generation Facility." The interconnection leads are considered part of the "existing generation Facility," but so are the generator, generator step-up transformer and other equipment associated with the generator. The project Background Resource Document (p.2) makes it clear that the interconnection to an existing generator facility is contemplated to be to the "existing interconnecting Facility that is owned by a generator" – i.e., the generator's interconnection leads. We propose that the term "its existing generation Facility" be replaced with "the Generator Owner's existing interconnecting transmission Facility."
Yes
No
FAC-003-X and FAC-003-3 both have similar "one half mile" language, the starting point for the one half mile is vague. In FAC-003-X, the language in 4.3.1 reads "Generator Owner that owns an overhead Facility that extends greater than one half mile beyond the fenced area of the switchyard, generating station or generating substation up to the point of interconnection with the Transmission system and ..." While we support the one half mile language, there are three possible starting points for the measurement of the one half mile: beyond the fenced area of (i) the switchyard, (ii) the generating station, or (iii) the generation substation. While a GO's fencing policy may differ between generation stations, the requirement to implement vegetation management should be clear. For clarity, while we believe that the language should retain flexibility with regards to "fencing" by the Generator Owner, it should be clear that the Generation Owner determines the starting point. Second, a Generator Owner's overhead Facility that is within the fence should explicitly not be applicable to the standard. Finally, we believe the language that refers to the "interconnection with the Transmission system" should be changed to "interconnection with a Transmission Owner's Facility. The reason is that the term "Transmission" which is defined in the NERC Glossary could be construed to include all of a Generator Owner's interconnection leads. (The definition is excerpted from the Glossary in our response to question 7) Therefore, we suggest that the language in 4.3.1 be modified as follows to make all of these points clear: A Generator Owner that owns an overhead Facility that extends greater than one half mile beyond the fenced area of either the generator switchyard, generating station or generating substation (as specified by the Generation Owner) up to the point of interconnection with a Transmission Owner's Facility and is operated 200 kV and above and any lower voltage lines designated by the RE as critical to the reliability of the electric system within the region is applicable to this standard."
Yes
Yes
Yes
FERC's Cedar Creek and Milford order (issued on June 16, 2011 and that is posted at <a href="http://www.nerc.com/files/Order_Denying_Appeals_RC11-1_RC11-2_20110616.pdf">http://www.nerc.com/files/Order_Denying_Appeals_RC11-1_RC11-2_20110616.pdf</a> ) listed several standards (in Paragraphs 71 and 87) that should be applicable to Cedar Creek and Milford, respectively. Because of this order, the drafting team should examine the listed standards and determine whether they are or are not applicable to Generator Owners or Generator Operators that own and are responsible for the operation of an overhead Facility. We emphasize that our

recommendation takes no position on any legal issues regarding the referenced order.
Yes
<p>While we generally agree with the drafting team's modifications to these standards, the team's approach may not directly resolve the fundamental registration issue regarding a Generation Owner that only owns non-integrated interconnection transmission facilities. The non-integrated interconnection transmission facilities owned by a GO are part of the Bulk Electric System (BES) because they are part of BES generation facilities. The ownership of these non-integrated facilities should not require a GO to also register as a Transmission Owner. The draft team has proposed modifying two FAC standards that would apply to such GO-owned interconnection transmission facilities. These GO-owned interconnection transmission facilities are not, however, "integrated" transmission facilities, as the drafting team correctly points out in its background resource document. A proposed solution to the Generation Owner registration issue is discussed below. NERC's Rules of Procedure (ROP) require entities to be registered in accordance with the definitions in the NERC Glossary of Terms Used in Reliability Standards (Glossary) and in accordance with the NERC Statement of Compliance Registry Criteria document. The Glossary has these definitions:</p> <ul style="list-style-type: none"> <li>• Generation Owner – Entity that owns and maintains generating units.</li> <li>• Transmission Owner – The entity that owns and maintains transmission facilities.</li> <li>• Facility – A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)</li> <li>• Transmission – An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.</li> <li>• Transmission Service – Services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery</li> </ul> <p>The drafting team should create a new definition for the term "integrated transmission facilities" and include this new definition in the Glossary. This definition should then be use to modify the definition of Generation Owner so that registration will be clear. While the team chose not to create any new definitions, we believe the registration issue cannot be resolved without modifying the definition of "Generation Owner</p> <p>The following definition is proposed for Integrated Transmission Facilities in the NERC Glossary:</p> <ul style="list-style-type: none"> <li>• Integrated Transmission Facilities (ITF) – ITF are the Facilities that are a subpart of Transmission system that are capable of carrying the flows from multiple generator plants at different points of interconnection for delivery to customers or to other electric systems. This proposed ITF definition builds upon FERC precedent in the Open Access Transmission Tariff (OATT) area. FERC has recognized that facilities that can carry flows from multiple supply points and deliver that power to either customers or other electric systems are proper facilities to include in an OATT and define the "Transmission System" for OATT purposes. The term "Transmission System" is an OATT-defined term that means "The facilities owned, controlled or operated by the Transmission Provider that are used to provide transmission service under Part II [Point-to-Point Transmission Service] and Part III [Network Integrated Transmission Service] of the Tariff." Under FERC's precedent, facilities such as generator step-up transformers and generator interconnecting transmission facilities have been excluded from the OATT; i.e., they are not facilities that provide Transmission Service because they cannot carry the flows from multiple supply points for delivery to customers or other electric system – their only use is to the Generation Owner. They perform two functions for a GO: 1. They deliver power from the GO's generators at a site to the OATT-defined Transmission System, and 2. They deliver off-site power from the OATT-defined Transmission System to the generators at a site when the generators at a site are not operating. While building on FERC OATT precedent, the proposed definition of "Integrated Transmission Facilities" does not require an applicable Transmission Service tariff to identify those facilities. Integrated Transmission Facilities are simply defined as those that capable of carrying flows from multiple supply points for delivery to customers or to other electric systems. Using the ITF definition, the definition of Generation Owner could be modified as follows:</li> <li>• Generation Owner – Entity that owns and maintains generating units but which does not own or maintain Integrated Transmission Facilities.</li> </ul>
Group
SPP Reliability Standards Development Team
Jonathan Hayes
No
We are concerned that some of the language is ambiguous. We would like to be clear that placing new requirements on Generator Owners that are already in place and have been in place under FERC

policy is inaccurate. We want to make sure that regardless of what the generator tie line is classified as, that a valid interconnection would go through the Generator Interconnection process under its applicable tariff. Format error in 2.4.1 should read 4.2.1 in applicability. We would like to see more definition in applicability section 4.2. How does the Generator Owner get involved in this process? The VRF for R4 is listed as a medium and appears to us as an administrative requirement. We would recommend that the VRF be changed to low. The moderate and high VSL for R1 seems to be duplicative. We would recommend taking a second look and would recommend that the high should be that "if you failed to do two of the following". We would recommend that the VSL on R4 read: "The responsible entity failed to make the requirements available within 30 business days after a request."

Yes

No

In both FAC003-3 and FAC003-X it lists "greater than one half mile cutoff". We would recommend that the distance cutoff be removed. We feel that overhead Facilities shouldn't be treated any differently than any other. Also we would like to see these two sections in both standard proposals reflect similar language for 4.3.1.

No

See comment above. We feel like there is no need for using a distance exclusion.

Yes

No

No

Individual

Amir Hammad

Constellation Power Generation

Yes

Yes

Yes

Yes

Yes

No

Yes

Constellation appreciates and supports the work of the standard drafting team. We recognize the significant time invested by technical experts from industry to consider the appropriate application of reliability standards to address concerns raised about coverage of transmission at the generator interface. The recent FERC Order concerning Cedar Creek and Milford wind suggested that the list of applicable standards needing revision should go beyond FAC-001 and FAC-003. We appreciate the discussion and concerns raised by FERC in the order; however, the discussion is limited by failing to consider these issues in light of the full package of existing standards. Below is a look at the FERC suggested standards and how they intersect with other standards: • PRC-001-1, Requirements R2, R2.2, R4 FERC expressed concern that certain protection system components may not be well coordinated with the RC. However, the same standard (PRC-1) addresses this issue by requiring all GOs to ensure coordination of their protection system with interconnected parties. Further, FAC-002 requires that all new facilities undergo reviews by the TOP, BA, etc. • PRC-004-1 Requirement R1

FERC expressed concern that certain protection system components may not be analyzed for misoperations. However, the same standard (PRC-4) addresses this issue by requiring all GOs to ensure that they analyze all misoperations on their protection system which would include the protection of the tie line. • TOP-004-2, Requirements R6, R6.1, R6.2, R6.3, R6.4; FERC expressed concern that coordination may be lacking between a GO and a TO with regards to the generator tie line. However, TOP standards applicable to GOs address this issue by requiring all GOs to coordinate all maintenance and emergency outages (both forced and planned) with all applicable interconnected parties. Further, all ISO procedures require the same of GOs. • PER-003-1, Requirements R1, R1.1, R1.2; FERC expressed concern that certain generator operators are responsible for the real time operation of the interconnected BES without being NERC certified operators, potentially causing a reliability gap. Generator Operators do not monitor and control the BES, they control and monitor generators that it operates and relays information to other operating entities. Therefore, NERC certification is not required. • FAC-003-1, Requirements R1, R2; FERC and the drafting team seem aligned in the need to revise this standard and the revision proposal includes such a revision. • TOP-001, Requirement R1 FERC expressed concern that certain tie lines may not be required to operate in such a way as to alleviate operational emergencies. However, IRO and TOP standards applicable to GOs address this issue by requiring all GOs to operate as directed by their TOP, BA, or RC as directed and must render emergency assistance. • FAC-014-2, Requirement R2. FERC expressed concern that certain tie lines may have a rating based on a methodology that may not be consistent with the methodology used by the RC. However, standards FAC-8 and FAC-9 address this issue by requiring all GOs to develop a methodology to rate all equipment, and that the RC has the authority to challenge the GO on that methodology. The onus is on the GO to either change their methodology and rating accordingly, or provide a technical justification as to why they cannot adopt the changes. Further, a generator will never be limited by its tie line, as a generator's profits are directly tied to its output. Therefore no generator would limit its facility to the equipment that is delivering that output.

Group
Westar Energy
Bo Jones
No
We suggest the VRF for R4 be changed from medium to low, as it is administrative in nature. We recommend the high VSL for R1 read, "The Transmission Owner failed to do two of the following."
Yes
No
The language in the applicability section 4.3.1 in both FAC-003-3 and FAC-003-X states "extends greater than one half mile beyond..." We propose that the SDT consider removing the distance exclusion to be consistent with language for Transmission Owner Facilities and treat all overhead facilities the same.
No
Yes
No
No
Individual
Kirit Shah
Ameren
Yes
Yes

Yes
No
(1)We do not agree there should be a ½ mile exemption. On what legitimate basis could we say the first ½ mile is not important? (2) There may be different usage of the term "point of interconnection" in the industry. We suggest the SDT to consider proposing a formal definition of this term.
Yes
No
No
Individual
Rex Roehl
Indeck Energy Services
Yes
Yes
No
4.3.1.3 is a regional variation. The ROP doesn't permit members of one region to vote on regional requirements for another region. A separate regional standard will be required.
Yes
Yes
No
Individual
Chad Bowman
CHPD
Yes
Yes
Yes
Yes
Yes
No
No
Individual
Andrew Z Pusstai
American Transmission Company



No
R1 wording in this draft only requires having published Facility connection requirements, but speaks nothing of specific required content of this published document. (R1) VSLs specifically reference R1. If VSLs continue to include assessment of how many R3 (R2 in present standard) requirements are met, a TO potentially has a redundant obligation under two separate requirements. R1 and R3 do not read in a manner consistent with (R1) VSLs. Since R2 only applies to Generator Owners, the (R2) VSL should use "Generator Owner" in place of "responsible entity."
No
ATC does not support the changes for FAC-003-X, however, ATC does support FAC-003-3. FAC-003-X Concerns The VRF and VSL tables do not correlate to the original FAC-003-1 levels of non-compliance section D.2. ATC believes that section D.2 should be rewritten to align with the already approved FAC-003-1. FAC-003-X Corrections- Applicability Section 4.3.1, sentence 3 – Transmission should not be capitalized. FAC-003-3 - No Concerns
Group
Southern Company
Antonio Grayson
No
Southern does not think that the revision to FAC-001-1 is necessary. A Generator Owner (GO) cannot assess reliability impacts to the Bulk Electric System (BES) and determine acceptability without support and involvement of the applicable owner and operator of the Transmission System. A generator tie-line does not equate to a Transmission System. A GO must already adhere to a TO's Facility connection requirements whether the GO wants to connect additional facilities or a third parties facilities to its own interconnection Facilities. Stated another way, the GO does not need Facility Connection requirements to govern how multiple units are tied to a collector bus so why are they needed for a third party to connect to an existing tie-line? In either case it is the interconnected TO that has connection requirements that must be fulfilled. The GO's Interconnection Agreement would prohibit it from connecting additional facilities without a new application for Interconnection Service with its interconnected Transmission Provider. A GO should not need to develop "connection requirements" unless it is in the business of owning and operating facilities independently of its interconnected Transmission Provider. We do not believe a reliability gap exists in FAC-001-1 because the requestor for interconnecting another Facility to an existing generation Facility must coordinate with the applicable TO, TP, and PA in accordance with FAC-002-0 to ensure they meet all applicable facility connection and performance requirements. If and when there is an agreement in place for a third party to connect to a generator tie-line then the tie-line would become part of the integrated system and its purpose and the owner's function would likely warrant registration as a TO/TOP and FAC-001 would then apply. The following excerpt from the 2010-07 Background Resource Document acknowledges that this may be necessary: "The drafting team also acknowledges that, if another party interconnects to a Facility owned by a Generator Owner, there may be the need to address MOD or TPL standards. However, the drafting team believes that this, too, is best handled through specific evaluation, perhaps accompanied by changes to the compliance registry. Entities that face this kind of scenario may also meet criteria applicable to other registrations such as Transmission Service Provider or Transmission Planner." B. If the Project 2010-07 Drafting Team decides to continue revising FAC-001-1, there are jurisdictional, interconnection policy and open access transmission tariff issues that will need to be considered. (1) Because of (a) jurisdiction under Section 215, (b) FERC's interconnection policy, and (c) the requirements of the pro forma open access transmission tariff (OATT), a GO should not be required to comply with FAC-001-1 until that GO's generating Facility reaches commercial operation. (a) Jurisdiction under FPA Section 215. First, it is not clear that NERC or FERC has jurisdiction under FPA Section 215 to require generation facilities that have not actually reached commercial operation to be subject to reliability standards. Section 215(a)(2) of the FPA defines the "Electric Reliability Organization" as "the organization certified by the Commission ... the

purpose of which is to establish and enforce reliability standards for the bulk-power system, subject to Commission review." Further, (a)(3) provides that "The term 'reliability standard' means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system. The term includes requirements for the operation of existing bulk-power system facilities ... the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system ...." Thus, under Section 215 NERC can develop reliability standards that address requirements for existing bulk-power system facilities (i.e., facilities that have reached "commercial operation") and for the design of planned additions or modifications. It is logical to interpret the phrase "design of new facilities" as meaning that new facilities must be designed to comply with existing reliability standards. However, it is not clear that this provision should be interpreted as requiring that a generating facility that has not yet reached commercial operation should be subject to reliability standards (including audit and penalties). Therefore, the GO with the existing generation facilities should not be required to incorporate the proposed generation facility into its Facility connection requirements before the proposed generation facility is subject to NERC or FERC jurisdiction. (b) FERC's interconnection policy. In addition, the revised FAC-001 would appear to place restrictions on interconnection customers in contravention of Order Nos. 2003 and 2006 (Standard Large and Small Interconnection Procedures and Agreements). FERC was very concerned about the ability of interconnection customers to interconnect their generating facilities and gave them a fair amount of flexibility. However, this revised FAC-001 would appear to restrict some of this flexibility. (i) Order No. 2003 gives the interconnection customer the ability to terminate a proposed interconnection on ninety days notice. Therefore, the interconnection customer is not required to build the facility. However, this revised FAC-001 appears to assume that the interconnection customer does not have this flexibility. What if the interconnection customer (the GO building a new generator on its site or the third party building a new generation facility) decides to terminate the Large Generator Interconnection Agreement (LGIA) or not proceed with the generation facility? In such event, the GO may be required to revert to its previous Facility connection requirements in order to accommodate the original configuration. (ii) The LGIA permits modifications to the proposed interconnection. How would this affect the Facility connection requirements? How long would the GO have to revise its Facility connection requirements? In the event that there is a single modification, or perhaps multiple modifications, how does the GO stay in compliance with this standard? (iii) FAC-001-1, R4 provides that each GO with Facility connection requirements and each TO shall maintain Facility connection requirements and make documentation of these requirements available to users of the Transmission System upon request. However, Large Generator Interconnection Procedures (LGIP), Section 3.4 requires the posting of certain interconnection information but the identity of the interconnection customer is not to be disclosed (unless it is an Affiliate). Requirement R4 would appear to potentially require disclosure of information and (more importantly) of the interconnection customer's identity in contravention of the requirements in Order No. 2003 and the LGIP. (c) OATT requirements. The definition of "applicable Generator Owner" (Section 4.2.1) and Requirement R2 provide that the GO will have an executed Agreement to evaluate the impact of interconnecting a new facility to the GO's existing generation facility. This statement is ambiguous. This statement could be understood to mean that the GO of the existing generation Facility will enter into an Agreement with the GO proposing to interconnect and the existing GO will evaluate the impact of the proposed interconnection. However, requests to interconnect new generation are processed under an OATT. In that case, it would be the Transmission Provider (not the existing GO) that would evaluate the impact of interconnecting the new facility. Thus, the language in FAC-001-1 would need to be revised to clarify that the owner of the new facility will need to interconnect under the OATT of an appropriate Transmission Provider (i.e., the Transmission Provider to which the existing GO is interconnected, not with the existing GO). Therefore, the owner of the new facility will most likely be the entity with the executed Agreement (with the Transmission Provider). Another consideration is that the existing GO could be developing a merchant transmission line. In that case, the existing GO would need to evaluate whether it needs have its own OATT and OASIS. In that case, the new generator owner would be interconnecting to the existing GO. However, the existing GO's line would not be a generator tie-line. This issue is not clear from the draft standard. (2) The following are suggested changes to FAC-001-1. (a) We recommend the Purpose statement be revised to state, "To avoid adverse impacts on BES reliability..." (b) The numbering for "Applicable Generator Owner" should be 4.2.1 instead of 2.4.1. (c) It is not clear who may request to interconnect to the Generator Owners' facility. The Background Resource document states that "[b]ecause Generator Owners may be requested to allow interconnection to their Facilities"

– this would imply that a third party may request interconnection to the Generator Owner’s Facilities. However, draft FAC-001-1 discusses “interconnecting another Facility to its existing generation Facility.” This issue needs to be clarified. Is it simply when a Generator Owner proposes to add a new facility to its existing facility or does it also include a third party request to interconnect to the Generator Owner facilities? (d) R4 should be revised to delete the requirement to maintain the Facility connection requirements because this is redundant to language in R1 (and R2, which we believe is not needed). In addition, R4 should be revised to state, “...on requests within five (5) business days” since the time requirement is essential for measurement of non-compliance as indicated by the VSLs. (e) The Severe VSL for R3 should be revised to delete the second portion which states, “The responsible entity does not have Facility connection requirements.” This non-compliance would be covered by the first portion of the two-part OR requirement (...four or more...). It is also covered by the Severe VSL of R1. (3) Effect of the proposed revisions to FAC-001-1 on FAC-002-1. (a) As drafted, there are scenarios under which a new GO may attempt to interconnect to an existing GO even though, as explained above, the interconnection should actually be done to the appropriate Transmission Provider. If the appropriate Transmission Provider is not included in the evaluation of the interconnection various types of harm may occur. In such event, the TPs and PAs should be indemnified from any liability with respect to performance of the evaluations required by FAC-002. (b) FAC-001 and FAC-002 should be revised to be clear that the existing GO and any new GOs must coordinate any interconnection with the appropriate Transmission Provider, TP and PA.

Yes

However, we do not believe it is necessary to require a GO to have Facility connection requirements as we discuss in our response to Question 1.

No

(1) We question whether R1 of FAC-003-3 would ever apply to a GO who owns transmission interconnection equipment. Can the SDT provide an example or two in the Guideline and Technical Basis section of the standard? (2) We recommend rearranging the language in R5 of FAC-003-3 to state, “The applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments when...” This places the “shall” at the beginning of the requirement which is clearer and consistent with the structure of the other requirements. (3) We question why there are no VSLs assigned to R4. Should there be? What are the consequences if a Regional Entity does not comply? (4) There does not appear to be any coordination with the Vegetation Management Standard Drafting Team (VMSDT) concerning proposed modifications to the standard. The VMSDT should be consulted.

No

We agree with a one-half mile line as being “within the Generator Owner’s line of sight and could be visually monitored for vegetation conditions on a routine basis.” However, we suggest that some generation interconnection Facilities greater than ½ mile in length could also fall within the GO’s line of sight or be constructed such that they should be considered for exemption. Thus, the Task Force should consider including exclusions for longer generator tie lines if the GO can provide sufficient justification. Examples of justifications could include (1) a clear line of sight, (2) pavement, gravel, or other non-vegetation covered path, or (3) routine monitoring is performed from a roadway parallel to the line, etc. Do not obviate any other transmission requirements such as the following (which are incorporated into the draft standard): i. Operated at 200kV or higher; or ii. Operated below 200kV and included in IROL; or iii. Operated below 200kV and inclusion in a Major WECC Transfer Path

Yes

Yes

Yes

Please see our Comments in response to Question 7.

Yes

(1) The SDT needs to review the June 16, 2011 FERC Order on Cedar Creek and Milford and factor this into the equation. The FERC Order concludes that the Cedar Creek and Milford entities must register as a TO and TOP. In addition to FAC-003, the Cedar Creek and Milford order lists the following standards and requirements that apply to these entities as a TO/TOP: • PER-003-1, R1, R1.1, R1.2 (requiring NERC-certified transmission operators); • PRC-001-1, R2, R2.2, R4, R6 (notification of relay or equipment failures); • PRC-004-1, R1 (analyzing protection system misoperations); • FAC-014-2, R2 (establishment of system operating limits); • TOP-001, R1

(authority to take actions to alleviate operating emergencies); • TOP-004-2, R6, R6.1, R6.2, R6.3, R6.4 (establishment of formal policies to address voltage levels, planned outages, switching, Interconnection Reliability Operating Limits, and System Operating Limits). The SDT needs to address these specific requirements in sufficient detail by either revising the Project 2010-07 Background Resource Document or proposing revisions to these standards to address any reliability gaps. For example, we recommend, as a minimum, that the Background Resource Document discussion under PRC-001-1 be revised to state (underlined text added), "Generator Operators and the scope of protection equipment for generation interconnection Facilities are already appropriately accounted for in this standard in requirements R1, R2, R3, and R5." Please note that this statement, even with our proposed revision, conflicts with the FERC Order on Cedar Creek and Milford, Paragraphs 64, 65, and 78 where FERC states that Cedar Creek and Milford must register as a TO and TOP to ensure the protection system coordination requirements in R2 and R4 of PRC-001 are met. Thus, the discussion for PRC-001-1 in the Project 2010-07 Background Resource Document needs additional language to demonstrate adequacy of the GO requirements in order to prevent GOs that own generation interconnection Facilities from having to register as a TO and TOP. (2) In addition, we believe the SDT should add supporting discussion to the Background Resource Document to explain why the following standards adequately cover GO/GOP requirements at the Transmission Interface: PRC-004-2, PRC-005-1, PRC-023-1. For example, the Background Resource Document could state that PRC-023-1 Section A.4 Applicability already includes, "4.2. Generator Owners with load-responsive phase protection systems as described in Attachment A, applied to facilities defined in 4.1.1 through 4.1.4." (3) Furthermore, FERC's analysis in the Cedar Creek and Milford order suggests that reliability gaps will occur if certain entities are not registered as TO/TOP. The GRTI SAR DT should assess why its findings are different from the Commission's findings. By way of background, the GRTI SAR DT provides that its own assessment of the GOTO Ad Hoc Group Final Report concludes with a belief that there are only two standards requiring modifications to address reliability gaps – FAC-001 and FAC-003 (Background Resource Document, page 3). FERC will most likely require that NERC clearly demonstrate and provide technical support for the position that GO's only need to comply with FAC-001 and FAC-003 and not the other standards noted by FERC. The Background Resource Document does not appear to provide adequate technical support for the GRTI SAR DT position. Therefore, the GRTI SAR DT should develop that technical support in preparation for the filing of these revised standards at FERC.

Individual

Michael Falvo

Independent Electricity System Operator

Yes

Yes

Yes

Yes

We generally agree with the proposed distance. However, we suggest that in Applicability Section 4.3.1 of the two draft standards, an equivalent kilometer value be inserted after the "one half mile".

Yes

No

No

Individual

Doug Hohlbaugh

FirstEnergy Corp

Yes

FirstEnergy (FE) appreciates the drafting team's careful consideration of the comments made by FE during the most recent informal comment period. The changes made to FAC-001 alleviate FE's prior concern related to a Generator Owner needing to maintain and publish a Facility Connection requirements document regarding facilities which are not yet subject to Open Access provisions. FE supports the team's changes to FAC-001-1 and the concept that a connection requirement document would be required upon the initial or 1st time a Generator Owner executes an Agreement to perform the reliability assessment required in FAC-002-1.

Yes

The one year lead time is sufficient lead-time to notice the GOs of new expectations required under FAC-001-1.

Yes

Yes

Yes

No

Yes

The June 16, 2011 FERC Order denying the appeals of two wind generating facilities—Cedar Creek and Milford – of the NERC determinations that Cedar Creek and Milford must each be registered as a transmission owner and transmission operator on the NERC Compliance Registry complicates the GO-TO drafting team's work. However, the issues may be distinct and different in the end. The existing GO-TO team's work product defines new reliability expectations for a generator owner regardless of whether or not the same entity is also being required to have a TO-TOP "light" compliance registration. In the Order, FERC describes what it believes are an appropriate limited set of TO-TOP requirements when a TO-TOP "light" registrations is deemed warranted for a traditional generation owner. The drafting team should describe what, if any, impact the FERC June 16 Order is having on its work scope. One minor comment for the background resource document. On page one, the last sentence of the 1st paragraph which currently reads " ... appropriate level of reliability for the BES." Consider changing to read " ... Adequate Level of Reliability for the BES." And, include a footnote directing the reader to NERC's definition/paper describing ALR. The later references to "adequate level of reliability" within the document (i.e. page 2, 2nd paragraph could then be reduced to the acronym ALR.

Individual

Sandy O'Connor

TransAlta Centralia Generation LLC

Yes

Yes

Yes

Yes

Yes

No

No

TransAlta Centralia Generation LLC (TransAlta) supports the recommendations put forward by the Project 2010-07 drafting team. The implementation of these recommendations will provide for much

needed certainty for owners and operators of generation facilities.
Group
PPL Supply Group
Annette Bannon
No
A Generator Owner subject to the proposed standard (i.e., with an executed Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility) should only be responsible for evaluating the impact of such interconnection on its facilities. Generation Owners should have no responsibility for evaluating impacts on interconnected or adjacent Transmission Owner systems. GOs do not have staff trained or tools available to perform the studies necessary to evaluate reliability impacts of such interconnections on Transmission Owner systems which can extend geographically far beyond the POI. The SDT should clarify that Transmission Owners are solely responsible for evaluating and addressing any impacts on their systems.
No
It may take longer since very few (if any) GOs are prepared to perform this type of work.
No
Version 3 (based on V2): Third Effective date appears to contain a typographical error. Version X (based on V1): Same as Version 3 comments. Please consider streamlining the section Background (Version 3).
No
Version 3 (based on V2): Comments: Although the "one half mile" is much clearer than "two spans", what is the rationale for choosing ½ mile as opposed to another length such as 1 or 2 miles? Version X (based on V1): Same as Version 3 comments
Yes
Yes
Group
ACES Power Members
Jason Marshall
No
We support the concept of modifying FAC-001-1 to include Generation Owners that own transmission lines that interconnect them to the BES for the purpose of eliminating the need to register Generation Owners as Transmission Owners. However, there are serious issues with the implementation of the FAC-001-1. The changes conflict with the tariff process of many established markets as well as the FERC pro forma tariff. Requests to interconnect are generally governed by tariffs. The request will be submitted to the transmission provider established by the tariff. The transmission provider will then perform the necessary studies such as system impact or feasibility studies to determine any necessary upgrades through its long-term planning function. After the completion of these studies or in parallel with them, the Transmission Owner (or Generation Owner that owns transmission) will perform the facility connection study. This may or may not require an additional contract as it may be governed completely under the tariff or may be covered under a blanket agreement in an organized market. The language referring to the executed Agreement in the standard should be dropped as it is confusing and may not cover many situations. Rather, the standard should apply to the Generation Owner that owns Transmission and is not registered as Transmission Owner. R2 should be modified such as the Generation Owner that owns Transmission is required to create facility connection requirements upon request from the Planning Coordinator or Transmission Planner. While the NERC Functional Model is not clear on the function that performs the interconnection study, it likely will be either the Transmission Planner or the Planning Coordinator. Interconnection studies are typically long-term planning studies. Thus, it is the Transmission Planner or Planning Coordinator that will receive the interconnection request and determine on whose equipment will be impacted. R3 is problematic and contradicts the purpose of R2. R3 requires the Generation Owner that owns Transmission to have Facility connection requirements at all times. It appears the drafting team

intended for R3 to simply define what must be included in the facility connection requirements. To do this, we suggest the drafting team remove the Generation Owner that owns Transmission from the requirement and copy the part 3.1 and its sub-parts to R2. The following language should be struck from R2: "to ensure compliance with NERC Reliability Standards and applicable Regional Entity, subregional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements". These requirements already exist elsewhere and inclusion here creates the potential for double jeopardy. R4 should be struck. There is no need for the Generator Owner that owns transmission to maintain its facility connection requirements. They should only be required to review and update them when they get a request. Tariff processes will already require them to make the facility connection requirements available to interconnection requesters.

Yes

Yes

Yes

Yes

No

No

**American Wind Energy Association  
Formal Comments on NERC Project 2010-07  
Generator Requirements at the Transmission Interface  
July 17, 2011**

The American Wind Energy Association (AWEA) appreciates the opportunity to submit these formal comments on the NERC Project 2010-07. AWEA supports the general direction indicated by both the Generator Requirements at the Transmission Interface Ad Hoc Group (GOTO Ad Hoc Group), and the Project 2010-07 Standards Development Team (SDT). We agree with the sentiments from both groups that a Generator Owner (GO) or Generator Operator (GOP) that also owns or operates a generator interconnection facility (GIF), should not be required to register as a Transmission Owner (TO) and/or Transmission Operator (TOP) strictly because they own or operate the GIF. We also agree that requiring these GOs or GOPs to comply with all the TO/TOP standards would have little effect on or benefits to reliability of the Bulk Electric System.

AWEA supports the aim of these groups to address any reliability gap that may exist with regard to GIFs by considering such facilities as part of the generating facility, and therefore also subject to the GO/GOP standards. AWEA also supports the approach of identifying a limited number of TO/TOP standards, such as FAC-001 and FAC-003, which should also apply to GIFs. We would be concerned, however, if additional requirements were added beyond these two, without serious consideration by the SDT and additional industry experts. The recent FERC order on the required registration as TOs and TOPs of two generator interconnection facilities may raise some question about the direction that the GO/TO and the SDT have taken so far on this topic. AWEA urges NERC and the SDT to use caution in considering any additional standards to apply to GIFs as the current approach of the GO/TO and SDT efforts have been generally supported. Consideration of any addition standards with respect to GIFs should be done on a standard-by-standard basis, reviewing the applicability of each standard as well as the impact on the reliability of the Bulk Electric System.

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Comments on Approach of Project 2010-07  
Generator Requirements at the Transmission Interface

The resolution of this issue regarding generator interconnection facilities should compel a certain result in determining how to classify and register generator tie-lines. Under the current standards, NERC is compelled to register owners with generator tie-lines as transmission owners. FERC has affirmed this. The changes to the standards should be such that NERC and FERC are compelled to consider the tie-lines as part of the generator facilities. The current proposal from this task force does not achieve that result. While the proposal does make very appropriate changes to certain reliability standards, it does not change the basic definition of the Bulk Electric System or change NERC's *Statement of Compliance Registry Criteria*, to determine how tie-lines are classified. Even though the relevant reliability standards would be changed so that they are also applicable to generator facilities, NERC and the regional entities will continue to apply the same definition and criteria and can continue to classify the tie-lines as Transmission.

The solution is to change the BES definition and NERC *Statement* as well as changing the applicability of the relevant reliability standards. The background resource document from this group suggests that a change in the BES definition was part of the overall solution, but the Project 2010-17 team did not address this in its proposed definition. The concept paper from the 2010-17 group does include "generator interconnection line leads," but the formal definition paper does not.

This project group should include in its formal proposal a change to the definition of BES, including generator interconnection facilities within the definition of generation.

# Consideration of Comments on Generator

## Requirements at the Transmission Interface – Project 2010-07

The Generator Requirements at the Transmission Interface Drafting Team thanks all commenters who submitted comments on the first formal posting for Project 2010-07—Generator Requirements at the Transmission Interface. These standards were posted for a 30-day public comment period from June 17, 2011 through July 17, 2011. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 43 sets of comments, including comments from approximately 143 different people from approximately 100 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

[http://www.nerc.com/filez/standards/Project2010-07\\_GOTO\\_Project.html](http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html)

The SDT thanks all stakeholders who provided comments. Your feedback helped the drafting team further modify its proposed standard changes, and the team believes that the changes are clearer and more technically sound because of it.

The SDT made a few substantive changes to both FAC-001 and both versions of FAC-003. With respect to FAC-001, many commenters suggested changes to both R2 and R3 to add clarity. The “activation” language in R2 now reads “...within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the Transmission System...” R3 has been modified so that it is clearer that only Generator Owners applicable in accordance with R2 are required to comply, and the word “protection” in R3.1.5 has been made lowercase. Per stakeholder comments, the SDT also removed the Generator Owner from R4, because they agree that that inclusion was redundant to language in R2. Because Generator Owners have been removed from the requirement (and thus the requirement is no longer within the SDT’s scope), the SDT reverted back to the original requirement language in the approved version of the standard.

Some commenters were still concerned with the 45 day “activation” point, and indicated that more time could be needed for compliance. The SDT reminded these commenters that the 45 day timeframe is 45 days from the time the entity has a study Agreement, not 45 days to execute the Agreement altogether. Any commenters who were concerned that their Facilities could never receive an interconnection request were reminded that if that’s the case, this standard would never apply to them. And those commenters who insisted that Generator Owners could never receive a request for interconnection were reminded that in the past (for instance, 134 FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities. Thus, the SDT thinks it is important to clarify the responsibilities related to such a request in NERC’s Reliability Standards.

With respect to FAC-003, many commenters focused on the half-mile qualifier in both versions of the standard. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: "...that extends greater than one mile beyond the fenced area of the generating station switchyard..." The SDT believes that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, the team maintains that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.

The majority of commenters did not suggest the addition of any standards or requirements to the team's scope of work, and a few commenters cautioned strongly against any additions. Some commenters suggested that the team consider including those standards and requirements listed in the June 2011 Cedar Creek and Milford FERC orders. The drafting team has considered the inclusion of the requirements listed in the Cedar Creek and Milford orders in the past, and we have been revisiting them throughout our process. We continue to conclude, with stakeholder support, that no additional substantive standard or requirement changes are necessary to achieve the goal of this project. With this posting, the drafting team has revisited those standards yet again and developed a comprehensive document and spreadsheet tracing our rationale (at every stage of the process) for not including additional standards or requirements. The team has elected to propose a slight clarifying change in PRC-004-2, but no changes to the applicability of that or any other standard.

While the drafting team will not be adding standards at this time because they do not believe such additions are technically justified or justified by stakeholder comments, the SDT will be seeking some additional informal feedback from industry groups to ensure that their technical justifications are sound and supported by others outside of the drafting team. The current draft documents showing the team's rationale and technical justification for including/excluding standards for revision under this project have been posted for information on the project page with this posting. If you have any specific feedback on these documents, you are welcome to email [mallory.huggins@nerc.net](mailto:mallory.huggins@nerc.net).

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 404-446-2560 or at [herb.schrayshuen@nerc.net](mailto:herb.schrayshuen@nerc.net). In addition, there is a NERC Reliability Standards Appeals Process.<sup>1</sup>

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<sup>1</sup> The appeals process is in the Standard Processes Manual:  
[http://www.nerc.com/docs/standards/sc/Standard\\_Processes\\_Manual\\_Approved\\_May\\_2010.pdf](http://www.nerc.com/docs/standards/sc/Standard_Processes_Manual_Approved_May_2010.pdf).

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The Industry Segments are:

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- 7 — Large Electricity End Users
- 8 — Small Electricity End Users
- 9 — Federal, State, Provincial Regulatory or other Government Entities
- 10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Notheast Power Coordinating Council										X
Additional Member		Additional Organization	Region	Segment Selection									
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10									
2.	Gregory Campoli	New York Independent System Operator	NPCC	2									
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2									
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1									
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1									
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10									
7.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3									
8.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5									
9.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5									
10.	Kathleen Goodman	ISO - New England	NPCC	2									
11.	Chantel Haswell	FPL Group, Inc.	NPCC	5									
12.	David Kiguel	Hydro One Networks Inc.	NPCC	1									
13.	Michael R. Lombardi	Northeast Utilities	NPCC	1									
14.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9									
15.	Bruce Metruck	New York Power Authority	NPCC	6									
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10									

Group/Individual	Commenter	Organization	Registered Ballot Body Segment																																																																																																									
			1	2	3	4	5	6	7	8	9	10																																																																																																
17. Robert Pellegrini	The United Illuminating Company	NPCC	1																																																																																																									
18. Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1																																																																																																									
19. Saurabh Saksena	National Grid	NPCC	1																																																																																																									
20. Michael Schiavone	National Grid	NPCC	1																																																																																																									
21. Wayne Sipperly	New York Power Authority	NPCC	5																																																																																																									
22. Donald Weaver	New Brunswick System Operator	NPCC	2																																																																																																									
23. Ben Wu	Orange and Rockland Utilities	NPCC	1																																																																																																									
2.	Group	Gerald Beckerle	SERC OC Standards Review Group			X		X																																																																																																				
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Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
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22.	William Berry	OMU	SERC	1, 3, 5									
23.	Brent Davis	Entergy	SERC	1, 3									
24.	Brad Young	LGE/KU	SERC	1, 3, 5									
25.	Wes Davis	SERC	SERC	10									
3.	Group	Carol Gerou	Midwest Reliability Organization's NERC Standards Review Forum (NSRF)		X	X	X	X	X	X			
<b>Additional Member</b>		<b>Additional Organization</b>		<b>Region</b>	<b>Segment Selection</b>								
1.	Mahmood Safi	Omaha Public Power Dist	MRO	1, 3, 5, 6									
2.	Chuck Lawrence	American Transmission Company	MRO	1									
3.	Tom Webb	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6									
4.	Jodi Jenson	Western Area Power Administration	MRO	1, 6									
5.	Ken Goldsmith	Alliant Energy	MRO	4									
6.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6									
7.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6									
8.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6									
9.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6									
10.	Joseph DePoorter	Madison Gas and Electric Company	MRO	3, 4, 5, 6									
11.	Scott Nichols	Rochester Public Utilities	MRO	4									
12.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6									
13.	Richard Burt	Minnkota Power Cooperative	MRO	1, 3, 5, 6									
14.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5									
15.	Scott Bos	Muscatine Power and Water	MRO	3, 4, 5, 6									
16.	Lee Kittleson	Otter Tail Power Company	MRO	5, 1, 3, 6									
17.	Marie Knox	Midwest ISO	MRO	2									
4.	Group	Connie Lowe	Electric Market Policy		X		X		X	X			
<b>Additional Member</b>		<b>Additional Organization</b>		<b>Region</b>	<b>Segment Selection</b>								
1.	Mike Crowley		SERC	1									
2.	Louis Slade		RFC	5, 6									
3.	Michael Gildea		NPCC	5, 6									
4.	Mike Garton		MRO	5, 6									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
5.	Group	Charles W. Long	SERC Planning Standards Subcommittee	X									X
<b>Additional Member</b>		<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>									
1.	John Sullivan	Ameren Services Co.	SERC	1									
2.	James Manning	NC Electric Membership Corp.	SERC	1									
3.	Philip Kleckley	SC Electric & Gas Co.	SERC	1									
4.	Pat Huntley	SERC Reliability Corp.	SERC	10									
5.	Bob Jones	Southern Company Services	SERC	1									
6.	Group	Jesus Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X				
<b>Additional Member</b>		<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>									
1.	Tino Zaragoza	IID	WECC	1									
2.	Jesus Sammy Alcaraz	IID	WECC	3									
3.	Diana Torres	IID	WECC	4									
4.	Marcela Caballero	IID	WECC	5									
5.	Cathy Bretz	IID	WECC	6									
7.	Group	Brent Ingebrigtsen	LG&E and KU Energy	X		X		X	X				
No additional members listed.													
8.	Group	John Seelke	Public Service Enterprise Group	X		X		X	X				
<b>Additional Member</b>		<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>									
1.	Ken Brown	PSE&G	RFC	1, 3									
2.	Clint Bogan	PSEG Fossil	RFC	5									
3.	Peter Dolan	PSEG ER&T	RFC	6									
4.	Scott Slickers	PSEG Fossil	NPCC	5									
5.	Eric Schmidt	PSEG ER&T	NPCC	6									
6.	Mikhail Falkovich	PSEG Fossil	ERCOT	5									
9.	Group	Jonathan Hayes	SPP Reliability Standards Development Team		X								
<b>Additional Member</b>		<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>									
1.	Valerie Pinamonti	AEP	SPP	1, 3, 5									
2.	Newton Alan Ward	AEP	SPP	1, 3, 5									



Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
3.	Mahmood Safi	OPPD	SPP	1, 3, 5									
4.	John Allen	SPRM	SPP	1, 4									
5.	Mitch Williams	Western Farmers	SPP	1, 3, 5									
6.	Robert Cox	Lee County Electric		NA									
7.	Don Reinert	Westar	SPP	1, 3, 5, 6									
8.	Robert Rhodes	SPP	SPP	2									
10.	Group	Annette Bannon	PPL Supply Group					X	X				
	<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>									
1.	Leland McMillan	PPL Montana, LLC	WECC	5									
2.	Don Lock	Lower Mount Bethel Energy, LLC	RFC	5									
3.		PPL Brunner Island, LLC	RFC	5									
4.		PPL Holtwood, LLC	RFC	5									
5.		PPL Martins Creek, LLC	RFC	5									
6.		PPL Montour, LLC	RFC	5									
7.	Mark Heimbach	PPL EnergyPlus, LLC	MRO	6									
8.		PPL EnergyPlus, LLC	NPCC	6									
9.		PPL EnergyPlus, LLC	RFC	6									
10.		PPL EnergyPlus, LLC	SERC	6									
11.		PPL EnergyPlus, LLC	SPP	6									
12.	John Cummings	PPL EnergyPlus, LLC	WECC	6									
11.	Group	Jason Marshall	ACES Power Members						X				
	<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>									
1.	Darin Adams	East Kentucky Power Cooperative	SERC	1, 3, 5									
2.	Susan Sosbe	Wabash Valley Power Association	RFC	3									
3.	Mohan Sachdeva	Buckeye Power	RFC	3, 5									
12.	Individual	Chris Higgins	Bonneville Power Administration		X		X		X	X			
13.	Individual	Jack Cashin	EPSA						X	X			
14.	Individual	Sandra Shaffer	PacifiCorp		X		X		X	X			
15.	Individual	Janet Smith, Regulatory	Arizona Public Service Company		X		X		X	X			

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
		Affairs Supervisor											
16.	Individual	Bo Jones	Westar Energy	X		X		X	X				
17.	Individual	Antonio Grayson	Southern Company					X					
18.	Individual	Mike Laney	Luminant Power					X					
19.	Individual	Thad Ness	American Electric Power	X		X		X	X				
20.	Individual	Edward Cambridge	APS	X		X		X					
21.	Individual	Gretchen Schott	BP Wind Energy North America Inc.										
22.	Individual	Katy Mirr	Sempra Generation					X					
23.	Individual	Brian Evans-Mongeon	Utility Services, Inc.								X		
24.	Individual	Samuel Reed	Tri-State Generation and Transmission, Inc.	X				X					
25.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
26.	Individual	Jody Nelson	Georgia Transmission Corporation	X									
27.	Individual	Bill Rees	BGE	X									
28.	Individual	John Bee	Exelom	X		X		X					
29.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP					X					
30.	Individual	Dale Fredrickson	Wisconsin Electric			X	X	X					
31.	Individual	Keith Morissette	Tacoma Power	X		X	X	X	X				
32.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
33.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
34.	Individual	Amir Hammad	Constellation Power Generation					X					
35.	Individual	Kirit Shah	Ameren	X		X		X	X				
36.	Individual	Rex Roehl	Indeck Energy Services					X					
37.	Individual	Chad Bowman	CHPD	X		X		X					
38.	Individual	Andrew Z Pusztai	American Transmission Company	X									
39.	Individual	Michael Falvo	Independent Electricity System Operator		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
40.	Individual	Doug Hohlbaugh	FirstEnergy Corp	X		X	X	X	X				
41.	Individual	Sandy O'Connor	TransAlta Centralia Generation LLC	X				X					
42.	Individual	Natalie McIntire	American Wind Energy Association										
43.	Individual	Donald Brookhyser	Cogeneration Association of California										

## 1. Do you support the proposed redline changes to FAC-001-1?

**Summary Consideration:** The SDT thanks all individuals and groups who provided feedback. The majority of comments indicated support for the SDT's changes to FAC-001, and the team has made additional changes, based on commenter feedback, where they believe those changes add clarity.

Commenters suggested changes to both R2 and R3 to add clarity. The "activation" language in R2 now reads "...within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System..." R3 has been modified so that it is clearer that only Generator Owners applicable in accordance with R2 are required to comply, and the word "protection" in R3.1.5 has been made lowercase. Per stakeholder comments, the SDT also removed the maintenance requirements for the Generator Owner from R2, and the Generator Owner from R4 altogether. Because Generator Owners have been removed from the requirement (and thus the requirement is no longer within the SDT's scope), the SDT reverted back to the original requirement language in the approved version of the standard.

Some commenters were still concerned with the 45 day "activation" point, and indicated that more time could be needed for compliance. The SDT reminded these commenters that the 45 day timeframe is 45 days from the time the entity has a study Agreement, not 45 days to execute the Agreement altogether. Any commenters who were concerned that their Facilities could never receive an interconnection request were reminded that if they are correct, this standard would not apply to them. Those commenters who insisted that Generator Owners could never receive a request for interconnection were reminded that in the past (for instance, 134 FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities. Thus, the SDT believes it is important to clarify the responsibilities related to such a request in NERC's Reliability Standards.

Some commenters brought up tariff-related issues. While the SDT has made changes attempting to clarify what was perceived by some commenters to be ambiguous qualifying language in R2, and while the commenters are correct that a valid interconnection would likely need to go through the generator interconnection process under its applicable tariff, it would be inappropriate for any market- or tariff-related language to be included in a NERC Reliability Standard. The goal of the drafting team was simply to clarify a Generator Owner's obligations, under NERC's Reliability Standards, for handling an interconnection request and the related interconnection requirements.

Several commenters also suggested changes to VRFs and VSLs. Because the SDT did not make any substantive changes to R1 or R4, the team only made changes to the VSLs or VRFs if we were correcting a typo; anything substantive would be outside the scope of this SDT. In the case of R2 and R3, changes were made per commenter suggestions.

Finally, the formatting error in the Applicability section has been corrected.

For a more detailed explanation of the team’s rationale, please see the accompanying FAC-001-1 technical justification.

Organization	Yes or No	Question 1 Comment
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	No	<p>In general, the NSRF supports the changes to FAC-001-1. However the 45 days to execute an agreement would be a significant burden on a Generator Operator that does not have an existing process in place. The NSRF believes an aggressive but realistic time frame is 120 days. This would allow sufficient time to develop the procedure and obtain the necessary technical and legal reviews.</p> <p>Please clarify why "Protection" is capitalized in section 3.1.5. "Protection System" is defined by NERC but "System Protection" is not.</p> <p>Recommend the "half mile" statement be included within the Applicability section of this Standard as it stated in FAC-003-X.</p>
<p><b>Response:</b> Thank you for your comment. The team proposed 45 days from the time the entity has a study Agreement, not 45 days to execute the Agreement altogether. Please see the SDT’s accompanying FAC-001-1 technical justification for a more detailed explanation of the team’s rationale for using that time frame. No change made.</p> <p>“Protection” in 3.1.5 has been made lowercase.</p> <p>With respect to the “half mile” comment, an entity could receive an interconnection request for its interconnection Facility at any point along that Facility. An exemption or exclusion based on the length of the Facility is not justified because doing so would create a reliability gap. No change made.</p>		
Public Service Enterprise Group	No	<p>The language in R2 needs to be clarified with regards to the term “its existing generation Facility.” The interconnection leads are considered part of the “existing generation Facility,” but so are the generator, generator step-up transformer and other equipment associated with the generator. The project Background Resource Document (p.2) makes it clear that the interconnection to an existing generator facility is contemplated to be to the “existing interconnecting Facility that is owned by a generator” - i.e., the generator’s interconnection leads. We propose that the term “its existing generation Facility” be replaced with “the Generator Owner’s existing interconnecting transmission Facility.”</p>
<p><b>Response:</b> Thank you for your comment. We agree that some additional specification could be useful, and we have used the suggested</p>		

Organization	Yes or No	Question 1 Comment
clarifying language.		
SPP Reliability Standards Development Team	No	<p>We are concerned that some of the language is ambiguous. We would like to be clear that placing new requirements on Generator Owners that are already in place and have been in place under FERC policy is inaccurate. We want to make sure that regardless of what the generator tie line is classified as, that a valid interconnection would go through the Generator Interconnection process under its applicable tariff.</p> <p>Format error in 2.4.1 should read 4.2.1 in applicability.</p> <p>We would like to see more definition in applicability section 4.2. How does the Generator Owner get involved in this process?</p> <p>The VRF for R4 is listed as a medium and appears to us as an administrative requirement. We would recommend that the VRF be changed to low.</p> <p>The moderate and high VSL for R1 seems to be duplicative. We would recommend taking a second look and would recommend that the high should be that “if you failed to do two of the following”.</p> <p>We would recommend that the VSL on R4 read: “The responsible entity failed to make the requirements available within 30 business days after a request.”</p>
<p><b>Response:</b> Thank you for your comment. We have attempted to clarify what was perceived by some commenters to be ambiguous qualifying language. You are correct that a valid interconnection would likely need to go through the generator interconnection process under its applicable tariff, but it would be inappropriate for any market- or tariff-related language to be included in a NERC Reliability Standard. The goal of the drafting team was simply to clarify a Generator Owner’s obligations, under NERC’s Reliability Standards, for handling an interconnection request and the related interconnection requirements.</p> <p>The format error in the applicability section has been corrected.</p> <p>A Generator Owner can get involved in the process by receiving a request for interconnection on their Facility and executing an Agreement to evaluate the reliability impact of that request. The team has attempted to clarify to qualifying language in the applicability section with its latest proposed changes. Please see the SDT’s accompanying FAC-001-1 technical justification for a more detailed explanation of the team’s rationale.</p> <p>With respect to the VRF for R4, we agree that “low” might be more appropriate, but that change is outside the scope of this drafting team. Your suggestion will be submitted in a Suggestion Form and added to NERC’s Issues Database to be addressed in a future project.</p>		

Organization	Yes or No	Question 1 Comment
<p>With respect to the moderate and high VSLs for R1, we agree that they are duplicative and believe this was a typo. Change made.</p> <p>With respect to the proposed language change in the VSL for R4, while we agree that the VSL should be written in the negative rather than the positive that change would be outside the scope of this drafting team. Your suggestion will be submitted in a Suggestion Form and added to NERC's Issues Database to be addressed in a future project.</p>		
PPL Supply Group	No	<p>A Generator Owner subject to the proposed standard (i.e., with an executed Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility) should only be responsible for evaluating the impact of such interconnection on its facilities. Generation Owners should have no responsibility for evaluating impacts on interconnected or adjacent Transmission Owner systems. GOs do not have staff trained or tools available to perform the studies necessary to evaluate reliability impacts of such interconnections on Transmission Owner systems which can extend geographically far beyond the POI. The SDT should clarify that Transmission Owners are solely responsible for evaluating and addressing any impacts on their systems.</p>
<p><b>Response:</b> Thank you for your comment. In the past (for instance, 134 FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities, and the drafting team thinks it is important to clarify the responsibilities related to such a request in NERC's Reliability Standards. The drafting team does not believe the standard as written requires the Generator Owner to be responsible for any interconnection Facility past the point of interconnection with the Transmission Owner's Facility. Please see the SDT's accompanying FAC-001-1 technical justification for a more detailed explanation of the team's rationale. No change made.</p>		
ACES Power Members	No	<p>We support the concept of modifying FAC-001-1 to include Generation Owners that own transmission lines that interconnect them to the BES for the purpose of eliminating the need to register Generation Owners as Transmission Owners. However, there are serious issues with the implementation of the FAC-001-1. The changes conflict with the tariff process of many established markets as well as the FERC pro forma tariff. Requests to interconnect are generally governed by tariffs. The request will be submitted to the transmission provider established by the tariff. The transmission provider will then perform the necessary studies such as system impact or feasibility studies to determine any necessary upgrades through its long-term planning function. After the completion of these studies or in parallel with them, the Transmission Owner (or Generation Owner that owns transmission) will perform the facility connection study. This may or may not require an additional contract as it may be governed completely under the tariff or may be covered under a blanket agreement in an organized</p>

Organization	Yes or No	Question 1 Comment
		<p>market. The language referring to the executed Agreement in the standard should be dropped as it is confusing and may not cover many situations. Rather, the standard should apply to the Generation Owner that owns Transmission and is not registered as Transmission Owner.</p> <p>R2 should be modified such as the Generation Owner that owns Transmission is required to create facility connection requirements upon request from the Planning Coordinator or Transmission Planner. While the NERC Functional Model is not clear on the function that performs the interconnection study, it likely will be either the Transmission Planner or the Planning Coordinator. Interconnection studies are typically long-term planning studies. Thus, it is the Transmission Planner or Planning Coordinator that will receive the interconnection request and determine on whose equipment will be impacted.</p> <p>R3 is problematic and contradicts the purpose of R2. R3 requires the Generation Owner that owns Transmission to have Facility connection requirements at all times. It appears the drafting team intended for R3 to simply define what must be included in the facility connection requirements. To do this, we suggest the drafting team remove the Generation Owner that owns Transmission from the requirement and copy the part 3.1 and its sub-parts to R2. The following language should be struck from R2: "to ensure compliance with NERC Reliability Standards and applicable Regional Entity, subregional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements". These requirements already exist elsewhere and inclusion here creates the potential for double jeopardy. R4 should be struck. There is no need for the Generator Owner that owns transmission to maintain its facility connection requirements. They should only be required to review and update them when they get a request. Tariff processes will already require them to make the facility connection requirements available to interconnection requesters.</p>
<p><b>Response:</b> Thank you for your comment. The drafting team believes that the execution of an Agreement to evaluate the reliability impact of interconnecting a third party Facility is the appropriate "activation" point for this standard for applicable Generator Owners. We have changed the language in the requirement to accommodate situations where it was not the Generator Owner itself that executed the Agreement. Please see the SDT's accompanying FAC-001-1 technical justification for a more detailed explanation of the team's rationale.</p> <p>R3 has been modified to more clearly apply only to Generator Owners in accordance with R2. Per your suggestion about maintenance, the drafting team has removed the maintenance obligation for Generator Owners. For more information on our rationale with respect to this, please see the accompanying FAC-001-1 technical justification document.</p>		
Westar Energy	No	We suggest the VRF for R4 be changed from medium to low, as it is administrative in nature. We recommend the high VSL for R1 read, "The Transmission Owner failed to do two of the



Organization	Yes or No	Question 1 Comment
		following.”
<p><b>Response:</b> Thank you for your comment. We agree that “low” might be more appropriate, but that change is outside the scope of this drafting team. Similarly, any change to the VSLs for R1 is outside the scope of this drafting team as that requirement does not include any reference to Generator Owners; we only made changes if the previous text appeared to have a typo. Your suggestions will be submitted in a Suggestion Form and added to NERC’s Issues Database to be addressed in a future project.</p>		
Southern Company	No	<p><b>A.</b> Southern does not think that the revision to FAC-001-1 is necessary. A Generator Owner (GO) cannot assess reliability impacts to the Bulk Electric System (BES) and determine acceptability without support and involvement of the applicable owner and operator of the Transmission System. A generator tie-line does not equate to a Transmission System. A GO must already adhere to a TO’s Facility connection requirements whether the GO wants to connect additional facilities or a third parties facilities to its own interconnection Facilities. Stated another way, the GO does not need Facility Connection requirements to govern how multiple units are tied to a collector bus so why are they needed for a third party to connect to an existing tie-line? In either case it is the interconnected TO that has connection requirements that must be fulfilled. The GO’s Interconnection Agreement would prohibit it from connecting additional facilities without a new application for Interconnection Service with its interconnected Transmission Provider. A GO should not need to develop “connection requirements” unless it is in the business of owning and operating facilities independently of its interconnected Transmission Provider.</p> <p>We do not believe a reliability gap exists in FAC-001-1 because the requestor for interconnecting another Facility to an existing generation Facility must coordinate with the applicable TO, TP, and PA in accordance with FAC-002-0 to ensure they meet all applicable facility connection and performance requirements. If and when there is an agreement in place for a third party to connect to a generator tie-line then the tie-line would become part of the integrated system and its purpose and the owner’s function would likely warrant registration as a TO/TOP and FAC-001 would then apply. The following excerpt from the 2010-07 Background Resource Document acknowledges that this may be necessary: “The drafting team also acknowledges that, if another party interconnects to a Facility owned by a Generator Owner, there may be the need to address MOD or TPL standards. However, the drafting team believes that this, too, is best handled through specific evaluation, perhaps accompanied by changes to the compliance registry. Entities that face this kind of scenario may also meet criteria applicable to other registrations such as Transmission Service Provider or Transmission Planner.”</p>

Organization	Yes or No	Question 1 Comment
		<p><b>B.</b> If the Project 2010-07 Drafting Team decides to continue revising FAC-001-1, there are jurisdictional, interconnection policy and open access transmission tariff issues that will need to be considered.</p> <p><b>(1)</b> Because of (a) jurisdiction under Section 215, (b) FERC’s interconnection policy, and (c) the requirements of the pro forma open access transmission tariff (OATT), a GO should not be required to comply with FAC-001-1 until that GO’s generating Facility reaches commercial operation.</p> <p><b>(a)</b> Jurisdiction under FPA Section 215. First, it is not clear that NERC or FERC has jurisdiction under FPA Section 215 to require generation facilities that have not actually reached commercial operation to be subject to reliability standards. Section 215(a)(2) of the FPA defines the “Electric Reliability Organization” as “the organization certified by the Commission ... the purpose of which is to establish and enforce reliability standards for the bulk-power system, subject to Commission review.” Further, (a)(3) provides that “The term ‘reliability standard’ means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system. The term includes requirements for the operation of existing bulk-power system facilities ... the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system ....” Thus, under Section 215 NERC can develop reliability standards that address requirements for existing bulk-power system facilities (i.e., facilities that have reached “commercial operation”) and for the design of planned additions or modifications. It is logical to interpret the phrase “design of new facilities” as meaning that new facilities must be designed to comply with existing reliability standards. However, it is not clear that this provision should be interpreted as requiring that a generating facility that has not yet reached commercial operation should be subject to reliability standards (including audit and penalties). Therefore, the GO with the existing generation facilities should not be required to incorporate the proposed generation facility into its Facility connection requirements before the proposed generation facility is subject to NERC or FERC jurisdiction.</p> <p><b>(b)</b> FERC’s interconnection policy. In addition, the revised FAC-001 would appear to place restrictions on interconnection customers in contravention of Order Nos. 2003 and 2006 (Standard Large and Small Interconnection Procedures and Agreements). FERC was very concerned about the ability of interconnection customers to interconnect their generating facilities and gave them a fair amount of flexibility. However, this revised</p>

Organization	Yes or No	Question 1 Comment
		<p>FAC-001 would appear to restrict some of this flexibility.</p> <p><b>(i)</b> Order No. 2003 gives the interconnection customer the ability to terminate a proposed interconnection on ninety days notice. Therefore, the interconnection customer is not required to build the facility. However, this revised FAC-001 appears to assume that the interconnection customer does not have this flexibility. What if the interconnection customer (the GO building a new generator on its site or the third party building a new generation facility) decides to terminate the Large Generator Interconnection Agreement (LGIA) or not proceed with the generation facility? In such event, the GO may be required to revert to its previous Facility connection requirements in order to accommodate the original configuration.</p> <p><b>(ii)</b> The LGIA permits modifications to the proposed interconnection. How would this affect the Facility connection requirements? How long would the GO have to revise its Facility connection requirements? In the event that there is a single modification, or perhaps multiple modifications, how does the GO stay in compliance with this standard?</p> <p><b>(iii)</b> FAC-001-1, R4 provides that each GO with Facility connection requirements and each TO shall maintain Facility connection requirements and make documentation of these requirements available to users of the Transmission System upon request. However, Large Generator Interconnection Procedures (LGIP), Section 3.4 requires the posting of certain interconnection information but the identity of the interconnection customer is not to be disclosed (unless it is an Affiliate). Requirement R4 would appear to potentially require disclosure of information and (more importantly) of the interconnection customer's identity in contravention of the requirements in Order No. 2003 and the LGIP.</p> <p><b>(c)</b> OATT requirements. The definition of "applicable Generator Owner" (Section 4.2.1) and Requirement R2 provide that the GO will have an executed Agreement to evaluate the impact of interconnecting a new facility to the GO's existing generation facility. This statement is ambiguous. This statement could be understood to mean that the GO of the existing generation Facility will enter into an Agreement with the GO proposing to interconnect and the existing GO will evaluate the impact of the proposed interconnection. However, requests to interconnect new generation are processed under an OATT. In that case, it would be the Transmission Provider (not the existing GO) that would evaluate the impact of interconnecting the new facility. Thus, the language in FAC-001-1 would need</p>

Organization	Yes or No	Question 1 Comment
		<p>to be revised to clarify that the owner of the new facility will need to interconnect under the OATT of an appropriate Transmission Provider (i.e., the Transmission Provider to which the existing GO is interconnected, not with the existing GO). Therefore, the owner of the new facility will most likely be the entity with the executed Agreement (with the Transmission Provider). Another consideration is that the existing GO could be developing a merchant transmission line. In that case, the existing GO would need to evaluate whether it needs have its own OATT and OASIS. In that case, the new generator owner would be interconnecting to the existing GO. However, the existing GO's line would not be a generator tie-line. This issue is not clear from the draft standard.</p> <p><b>(2)</b> The following are suggested changes to FAC-001-1.</p> <p><b>(a)</b> We recommend the Purpose statement be revised to state, "To avoid adverse impacts on BES reliability..."</p> <p><b>(b)</b> The numbering for "Applicable Generator Owner" should be 4.2.1 instead of 2.4.1.</p> <p><b>(c)</b> It is not clear who may request to interconnect to the Generator Owners' facility. The Background Resource document states that "[b]ecause Generator Owners may be requested to allow interconnection to their Facilities" - this would imply that a third party may request interconnection to the Generator Owner's Facilities. However, draft FAC-001-1 discusses "interconnecting another Facility to its existing generation Facility." This issue needs to be clarified. Is it simply when a Generator Owner proposes to add a new facility to its existing facility or does it also include a third party request to interconnect to the Generator Owner facilities?</p> <p><b>(d)</b> R4 should be revised to delete the requirement to maintain the Facility connection requirements because this is redundant to language in R1 (and R2, which we believe is not needed). In addition, R4 should be revised to state, "...on requests within five (5) business days" since the time requirement is essential for measurement of non-compliance as indicated by the VSLs.</p> <p><b>(e)</b> The Severe VSL for R3 should be revised to delete the second portion which states, "The responsible entity does not have Facility connection requirements." This non-compliance would be covered by the first portion of the two-part OR requirement (...four or more...). It is also covered by the Severe VSL of R1.</p> <p><b>(3)</b> Effect of the proposed revisions to FAC-001-1 on FAC-002-1.</p>

Organization	Yes or No	Question 1 Comment
		<p><b>(a)</b> As drafted, there are scenarios under which a new GO may attempt to interconnect to an existing GO even though, as explained above, the interconnection should actually be done to the appropriate Transmission Provider. If the appropriate Transmission Provider is not included in the evaluation of the interconnection various types of harm may occur. In such event, the TPs and PAs should be indemnified from any liability with respect to performance of the evaluations required by FAC-002.</p> <p><b>(b)</b> FAC-001 and FAC-002 should be revised to be clear that the existing GO and any new GOs must coordinate any interconnection with the appropriate Transmission Provider, TP and PA.</p>
<p><b>Response:</b> Thank you for your comment. The drafting team has considered the jurisdictional, interconnection policy and open access transmission issues that you raise. But in the past (for instance, 134 FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities, and the drafting team thinks it is important to clarify the responsibilities related to such a request in NERC’s Reliability Standards. You are correct that a jurisdictional, interconnection policy, and open access transmission tariff issues maybe have an impact, but it would be inappropriate for any market- or tariff-related language to be included in a NERC Reliability Standard. The goal of the drafting team was simply to clarify a Generator Owner’s obligations, under NERC’s Reliability Standards, for handling an interconnection request and the related interconnection requirements. Please see the SDT’s accompanying FAC-001-1 technical justification for a more detailed explanation of the team’s rationale.</p> <p>With respect to your suggested changes in section 2:</p> <ol style="list-style-type: none"> <li>Any change to the purpose statement would be outside the scope of this team. Please submit a <a href="#">Suggestion Form</a> to NERC if you continue to feel that this change is necessary.</li> <li>That formatting change has been made.</li> <li>The drafting team has worked to clarify who may request to interconnect to the Generator Owner’s Facility.</li> <li>The maintenance requirements in R2 and R4 are no longer applicable to Generator Owners. For more information on our rationale on this issue, please see the accompanying FAC-001-1 technical justification document.</li> <li>The drafting team agrees that the second portion of the Severe VSL for R3 is redundant. While other changes to VSLs and VRFs have been outside the scope of the team, because the SDT has made changes to R3, we feel comfortable making this change.</li> </ol> <p>For a more detailed justification of our changes to FAC-001 with respect to your comments in the third section, please see the FAC-001 justification document that is posted with these standard changes.</p>		
American Electric Power	No	There are substantial reliability issues, as well as additional regulatory, tariff, coordination, and generator and interconnection facility issues, which need to be dealt with before AEP could agree to such requirements. It is not clear that a generator can receive a request for

Organization	Yes or No	Question 1 Comment
		interconnection. We recommend adding qualifier text which states the standard only applies *if* an entity plans to allow such a requested interconnection. This would allow an entity to document that they do not plan to allow such interconnections.
<p><b>Response:</b> Thank you for your comment. In the past (for instance, 134 FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities, and the drafting team thinks it is important to clarify the responsibilities related to such a request in NERC’s Reliability Standards. No change made.</p>		
APS	No	Do not agree with adding GO to FAC-001-1
<p><b>Response:</b> Thank you for your comment. The vast majority of stakeholder commenters and the drafting team continue to support the addition of the Generator Owner to the applicability of FAC-001-1. No change made.</p>		
Exelon	No	Exelon does not agree that this standard should be broadly applied to a GO. GOs who do not own a switchyard and whose point of interconnection is a disconnect switch associated with the generator leads prior to the switchyard should be excluded from this standard. If a group of GOs share a generator tie line, then the associated Interconnect Agreement that each of the GO has with the applicable TO and/or TOP should address how these shared connections will effect the system. GOs may not have the resources or expertise to conduct the required interconnect studies to meet this standard
<p><b>Response:</b> Thank you for your comment. The standard does not automatically apply to all Generator Owners; rather, it applies only to those Generator Owners with an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the Transmission System. The drafting team believes that it has built the appropriate amount of time into the standard to allow an applicable Generator Owner to evaluate the impact of an Interconnect Agreement and obtain or contract for the necessary resources and expertise. Please see the SDT’s accompanying FAC-001-1 technical justification for a more detailed explanation of the team’s rationale. No change made.</p>		
Manitoba Hydro	No	The Applicable Entities now include a Generator Owner that meets the following condition: ‘Generator Owner with an executed Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility.’ A Generator Owner should not have such power. In many instances Generator Owners do not have the models or expertise to perform interconnection studies to determine if there is an impact on the Transmission Network. All interconnection requests should be implemented by the Transmission Owner (TO) regardless if the interconnection point is within a Generation Owner

Organization	Yes or No	Question 1 Comment
		<p>facility or End-User facility. The TO is in the best position to set unbiased connection requirements to ensure the reliability of the BES is maintained. If a mechanism is created to allow interconnection to a BES line owned by Generator Owner, then it is essential for this Generator Owner providing this interconnection service to be a TO to ensure all reliability standards, including the protection standards, are met so the reliability of the BES is maintained. The drafting team should demonstrate where this situation is occurring. If the redline changes are implemented, could Generator Owner #1 permit Generator Owner #2 to interconnect one of their generators within Generator Owner #1's Facility? Would Generator Owner #2 then need to have an executed Agreement to permit further generator interconnection? From a Transmission Owner viewpoint, it is tough enough to coordinate generator connection queues among adjacent TOs. Having to coordinate with Generator Owners as well would greatly increase the complexity of coordination.</p>
<p><b>Response:</b> Thank you for your comment. In the past (for instance, 134 FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities, and the drafting team thinks it is important to clarify the responsibilities related to such a request in NERC's Reliability Standards. No change made.</p>		
American Transmission Company	No	<p>R1 wording in this draft only requires having published Facility connection requirements, but speaks nothing of specific required content of this published document. (R1) VSLs specifically reference R1. If VSLs continue to include assessment of how many R3 (R2 in present standard) requirements are met, a TO potentially has a redundant obligation under two separate requirements. R1 and R3 do not read in a manner consistent with (R1) VSLs. Since R2 only applies to Generator Owners, the (R2) VSL should use "Generator Owner" in place of "responsible entity."</p>
<p><b>Response:</b> Thank you for your comment. The drafting team has removed the second portion of the Severe VSL for R3 to eliminate potential redundancy with the VSLs for R1 and R2. The VSL for R2 now refers to "Generator Owner" rather than "responsible entity."</p>		
Xcel Energy	Yes	<p>We believe it would be helpful to put explanatory wording in that if an entity is already registered as a Transmission Owner and Generator Owner, the Generator Owner portion of that entity would not have to have a separate set of interconnection requirements.</p>
<p><b>Response:</b> Thank you for your comment. The Facility in question in the standard would either be owned by the Generator Owner or the Transmission Owner. The owner must meet the requirement. The SDT does not determine how an entity complies, though we could expect that if an entity is already an Transmission Owner, it could easily simply apply its already existing set of interconnection requirements to any</p>		



Organization	Yes or No	Question 1 Comment
new Facilities that are applicable under this standard.		
Ingleside Cogeneration LP	Yes	However, there may need to be a variance for ERCOT because the Power Generating Companies in ERCOT are not allowed to own transmission assets.
<b>Response:</b> Thank you for your comment. If companies in ERCOT are not allowed to own transmission assets, the drafting team assumes that they would also never be in a position to have an Agreement to execute the reliability impact of an interconnection request. No change made.		
Georgia Transmission Corporation	Yes	We commend the drafting team for their efforts to address gaps in Facility Connection Requirements. We believe that the requirements under R3 should be limited to Generator owned equipment to avoid duplication of efforts. A Generator Owner receiving an interconnection request is required to submit an interconnection request to the Transmission Owner which in turn would study the impact of such a request on the Transmission System. Therefore there is no gap as far as the Integrated Transmission System that the third party is interconnecting to through the Generator Owner. However, Generator Owners are responsible for verifying that their equipment is capable of accommodating the interconnection request.
<b>Response:</b> Thank you for your comment. The SDT does not believe that R3 is duplicative; there is no reason to assume that the Transmission Owner or the applicable Generator Owner would be addressing anything but the equipment that it owns. No change made.		
BGE	Yes	This change closes the gap in areas not already covered under FAC-003-1 in a continuous improvement effort to ensure vegetation-related transmission reliability for applicable lines.
<b>Response:</b> Thank you for your comment.		
FirstEnergy Corp	Yes	FirstEnergy (FE) appreciates the drafting team's careful consideration of the comments made by FE during the most recent informal comment period. The changes made to FAC-001 alleviate FE's prior concern related to a Generator Owner needing to maintain and publish a Facility Connection requirements document regarding facilities which are not yet subject to Open Access provisions. FE supports the team's changes to FAC-001-1 and the concept that a connection requirement document would be required upon the initial or 1st time a Generator Owner executes an Agreement to perform the reliability assessment required in FAC-002-1.
<b>Response:</b> Thank you for your comment.		



Organization	Yes or No	Question 1 Comment
Sempra Generation	Yes	Sempra Generation supports the proposal for the compliance obligations under R2 associated with an interconnection request not to be triggered until an interconnection study agreement has been executed.
<b>Response:</b> Thank you for your comment.		
Arizona Public Service Company	Yes	These comments supersede the previous comments submitted by Arizona Public Service Company on July 7, 2011.
<b>Response:</b> Thank you for your comment.		
SERC OC Standards Review Group	Yes	Consider a better definition of what constitutes an “applicable” generator owner or point to the document that explains the definition.
<b>Response:</b> Thank you for your comment. The drafting team attempted to clarify the description of an “applicable” Generator Owner in the latest standards changes.		
Imperial Irrigation District (IID)	Yes	
PacifiCorp	Yes	
Ameren	Yes	
Luminant Power	Yes	
Constellation Power Generation	Yes	
SERC Planning Standards Subcommittee	Yes	
Duke Energy	Yes	

Organization	Yes or No	Question 1 Comment
Tri-State Generation and Transmission, Inc.	Yes	
Electric Market Policy	Yes	
Bonneville Power Administration	Yes	
Indeck Energy Services	Yes	
CHPD	Yes	
BP Wind Energy North America Inc.	Yes	
Independent Electricity System Operator	Yes	
Tacoma Power	Yes	
Northeast Power Coordinating Council	Yes	
TransAlta Centralia Generation LLC	Yes	
EPSA		<p>Background: The Electric Power Supply Association (EPSA) endorsed the initial recommendations of the Ad Hoc Group for Generator Requirements at the Transmission Interface, offered informal comments on the March 2011 White Paper Proposal for Project 2010-07 and now appreciates this opportunity to provide comments on the questions posted June 17, 2011. Since NERC's creation of the "GOTO Team" in February of 2009, EPSA has supported the efforts of Ad-Hoc Group and now the Project 2010-07 Standards Drafting Team (SDT). While EPSA members' compliance registration includes several functional entity types, the bulk of competitive suppliers' registrations are as Generator Owners (GOs) and Generator</p>

Organization	Yes or No	Question 1 Comment
		<p>Operators (GOPs).</p> <p>EPSA applauds the SDT’s decision to recommend the use the “intent of obligation” as the reason for application of FAC-001 rather than the receipt of request for interconnection and thereby supports the revisions to FAC-001-1. The proposed modification to FAC-001 (a new R2) would require a GO to develop “Facility connection requirements” within “45 days of executing an Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility...” The use of the agreement execution is a more reasonable triggering mechanism for FAC-001 application and compliance. The SDT’s recommendation intentionally excluded specific reference to the form of agreement to avoid commingling commercial and reliability aspects in reliability standards.</p> <p>However, the existing language may still may mix commercial and reliability issues. The accompanying project Background Resource Document (p.2) makes it clear that the interconnection to an existing generator facility is contemplated to be the “existing interconnecting Facility that is owned by a generator” - that is, the generator’s lead. The generator’s leads are considered part of the “existing generator Facility,” however, the generator, step-up transformer and other equipment that is within the generator switchyard can also be considered part of the Facility. FERC requires all transmission facilities to be available for “open access.” A generator lead would become open access if another customer interconnected to it. Therefore FAC-001-1 could be made clearer by modifying the language regarding the 45-day trigger as follows: within “45 days of executing an Agreement to evaluate the reliability impact of interconnecting another Facility to its the Generator Owner’s existing generation interconnecting transmission Facilities...” This modification would make it clear that the requirement does not apply to an entity that wants to, for example, connect a new generator within the fenced-in site of the existing generator, but instead only applies to request to interconnect to the generator lead.</p>
<p><b>Response:</b> Thank you for your comment. The drafting team has attempted to make this clarification regarding the “activation” of the applicability of this standard with respect to Generator Owners.</p>		
Utility Services, Inc.		
LG&E and KU Energy		

Organization	Yes or No	Question 1 Comment
Wisconsin Electric		

**2. Do you support the one year compliance timeframe for Generator Owners as proposed in the Implementation Plan for FAC-001-1?**

**Summary Consideration:** Most commenters supported the one year compliance timeframe for Generator Owners as proposed in the Implementation Plan for FAC-001-1. A few suggested a longer timeframe, but the drafting team believes it has built in the appropriate amount of time by giving a year in the implementation plan and then waiting to “activate” the standard until a Generator Owner has an executed Agreement to evaluate the reliability impact of the interconnection request.

Organization	Yes or No	Question 2 Comment
Manitoba Hydro	No	See question #1 comments. We do not support changing the applicability of FAC-001-1 to include Generator Owners ‘with an executed Agreement’ or Generator Owners that own BES transmission.
<b>Response:</b> Thank you for your comment. Please see our response to your Question 1 comments above.		
Ingleside Cogeneration LP	No	As drafted, the document still refers to generation interconnection lines as transmission lines in critical places. We understand that the SDT has taken significant steps to minimize this in both FAC-001 and FAC-003 and has had discussions with NERC about not registering GOs as TOs; however, this lack of distinction between high voltage generation interconnection lines and actual transmission lines still presents a difficult situation for Generations Owners and a source of contention with Reliability Entities. This could be resolved somewhat by using the non-defined term “generation interconnection lines” in place of “transmission lines” in, for example, section 4.3.1. Since the term “transmission line” is also undefined, this would seem to be a reasonable approach.
<b>Response:</b> Thank you for your comment. We have provided a disclaimer about the use of the term “transmission lines” in FAC-003, and have avoided use of the term elsewhere.		
APS	No	Leave the GO out of the standard.
<b>Response:</b> Thank you for your comment. In the past (for instance, 134 FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities, and the drafting		

Organization	Yes or No	Question 2 Comment
<p>team thinks it is important to clarify the responsibilities related to such a request in NERC's Reliability Standards by including applicable Generator Owners in FAC-001-1.</p>		
SERC OC Standards Review Group	No	We feel that an 18 month implementation plan would be more conducive for generators to meet these new requirements
<p><b>Response:</b> Thank you for your comment. The drafting team believes it has built in an adequate amount of time by giving a year in the implementation plan and then waiting to "activate" the standard until a Generator Owner has an executed Agreement to evaluate the reliability impact of the interconnection request.</p>		
PPL Supply Group	No	It may take longer since very few (if any) GOs are prepared to perform this type of work.
<p><b>Response:</b> Thank you for your comment. The drafting team believes it has built in the appropriate amount of time by giving a year in the implementation plan and then waiting to "activate" the standard until a Generator Owner has an executed Agreement to evaluate the reliability impact of the interconnection request.</p>		
BGE	Yes	This requirement is consistent with the initial time frame when FAC-003-1 was first implemented.
<p><b>Response:</b> Thank you for your comment.</p>		
Southern Company	Yes	However, we do not believe it is necessary to require a GO to have Facility connection requirements as we discuss in our response to Question 1.
<p><b>Response:</b> Thank you for your comment. Please see our response to your Question 1 comments above.</p>		
FirstEnergy Corp	Yes	The one year lead time is sufficient lead-time to notice the GOs of new expectations required under FAC-001-1.
<p><b>Response:</b> Thank you for your comment.</p>		
Northeast Power Coordinating	Yes	

Organization	Yes or No	Question 2 Comment
Council		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	
Electric Market Policy	Yes	
SERC Planning Standards Subcommittee	Yes	
Imperial Irrigation District (IID)	Yes	
Public Service Enterprise Group	Yes	
SPP Reliability Standards Development Team	Yes	
ACES Power Members	Yes	
Bonneville Power Administration	Yes	
EPSA	Yes	
PacifiCorp	Yes	
Arizona Public Service Company	Yes	

Organization	Yes or No	Question 2 Comment
Westar Energy	Yes	
Luminant Power	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Sempra Generation	Yes	
Tri-State Generation and Transmission, Inc.	Yes	
Xcel Energy	Yes	
Tacoma Power	Yes	
Duke Energy	Yes	
Constellation Power Generation	Yes	
Ameren	Yes	
Indeck Energy Services	Yes	
CHPD	Yes	
Independent Electricity System Operator	Yes	



Organization	Yes or No	Question 2 Comment
TransAlta Centralia Generation LLC	Yes	
Georgia Transmission Corporation		
Wisconsin Electric		
Utility Services, Inc.		
Exelom		
LG&E and KU Energy		
American Transmission Company		

**3. Taking into consideration that only one of the versions of FAC-003 will actually be implemented, a decision that will be made as the Project 2010-07 drafting team learns more about the status of Project 2007-07—Vegetation Management, do you support the proposed redline changes to FAC-003-X and FAC-003-3?**

**Summary Consideration:** The SDT thanks all individuals and groups who provided feedback. The majority of comments indicated support for the SDT’s changes to FAC-003-X and FAC-003-3, and the drafting team made additional changes, based on commenter feedback, where the team believes those changes add clarity.

Many commenters focused on the half-mile qualifier in FAC-003-X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: “...that extends greater than one mile beyond the fenced area of the generating station switchyard...” The drafting team believes that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, the team maintains that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.

One commenter caught typos in the Effective Dates sections of the standards, and those typos have been corrected.

Single commenters brought up minority issues, but the SDT found no justification for these issues. We address those minority issues in our responses to the specific comments below.

Organization	Yes or No	Question 3 Comment
American Transmission Company	No	<p>ATC does not support the changes for FAC-003-X, however, ATC does support FAC-003-3.</p> <p>FAC-003-X Concerns. The VRF and VSL tables do not correlate to the original FAC-003-1 levels of non-compliance section D.2. ATC believes that section D.2 should be rewritten to align with the already approved FAC-003-1.</p> <p>FAC-003-X Corrections- Applicability Section 4.3.1, sentence 3 - Transmission should not be capitalized.</p>

Organization	Yes or No	Question 3 Comment
		FAC-003-3 - No Concerns
<p><b>Response:</b> Thank you for your comment. The VSLs and VRFs in FAC-003-X were taken from already approved NERC projects to update all early versions of standards with VSLs and VRFs instead of levels of non-compliance. Any additional changes to those VSLs and VRFs would be beyond the scope of this drafting team. No change made.</p> <p>Applicability Section 4.3.1 no longer includes a capitalized version of Transmission (just a reference to the "Transmission Owner's Facility").</p>		
Public Service Enterprise Group	No	<p>FAC-003-X and FAC-003-3 both have similar "one half mile" language, the starting point for the one half mile is vague. In FAC-003-X, the language in 4.3.1 reads "Generator Owner that owns an overhead Facility that extends greater than one half mile beyond the fenced area of the switchyard, generating station or generating substation up to the point of interconnection with the Transmission system and ...". While we support the one half mile language, there are three possible starting points for the measurement of the one half mile: beyond the fenced area of (i) the switchyard, (ii) the generating station, or (iii) the generation substation. While a GO's fencing policy may differ between generation stations, the requirement to implement vegetation management should be clear. For clarity, while we believe that the language should retain flexibility with regards to "fencing" by the Generator Owner, it should be clear that the Generation Owner determines the starting point.</p> <p>Second, a Generator Owner's overhead Facility that is within the fence should explicitly not be applicable to the standard. Finally, we believe the language that refers to the "interconnection with the Transmission system" should be changed to "interconnection with a Transmission Owner's Facility. The reason is that the term "Transmission" which is defined in the NERC Glossary could be construed to include all of a Generator Owner's interconnection leads. (The definition is excerpted from the Glossary in our response to question 7) Therefore, we suggest that the language in 4.3.1 be modified as follows to make all of these points clear: A Generator Owner that owns an overhead Facility that extends greater than one half mile beyond the fenced area of either the generator switchyard, generating station or generating substation (as specified by the Generation Owner) up to the point of interconnection with</p>

Organization	Yes or No	Question 3 Comment
		<p>a Transmission Owner’s Facility and is operated 200 kV and above and any lower voltage lines designated by the RE as critical to the reliability of the electric system within the region is applicable to this standard.”</p>
<p><b>Response:</b> Thank you for your comment. The drafting team received many comments about the half-mile qualifier in FAC-003-X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: “...that extends greater than one mile beyond the fenced area of the generating station switchyard...” We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.</p> <p>The drafting team agrees that “interconnection with a Transmission Owner’s Facility” adds clarity. That change has been made.</p>		
<p>SPP Reliability Standards Development Team</p>	<p>No</p>	<p>In both FAC-003-3 and FAC-003-X it lists “greater than one half mile cutoff”. We would recommend that the distance cutoff be removed. We feel that overhead Facilities shouldn’t be treated any differently than any other. Also we would like to see these two sections in both standard proposals reflect similar language for 4.3.1.</p>
<p><b>Response:</b> Thank you for your comment. The drafting team received many comments about the half-mile qualifier in FAC-003-X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: “...that extends greater than one mile beyond the fenced area of the generating station switchyard...” We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.</p>		

Organization	Yes or No	Question 3 Comment
PPL Supply Group	No	<p>Version 3 (based on V2): Third Effective date appears to contain a typographical error.</p> <p>Version X (based on V1): Same as Version 3 comments.</p> <p>Please consider streamlining the section Background (Version 3).</p>
<p><b>Response:</b> Thank you for your comment. The typographical errors were corrected in both versions of the standard. Streamlining the Background section in Version 3 is not within the scope of this drafting team. No change made.</p>		
Westar Energy	No	<p>The language in the applicability section 4.3.1 in both FAC-003-3 and FAC-003-X states "extends greater than one half mile beyond..." We propose that the SDT consider removing the distance exclusion to be consistent with language for Transmission Owner Facilities and treat all overhead facilities the same.</p>
<p><b>Response:</b> Thank you for your comment. The drafting team received many comments about the half-mile qualifier in FAC-003-X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: "...that extends greater than one mile beyond the fenced area of the generating station switchyard..." We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.</p>		
Southern Company	No	<p>(1) We question whether R1 of FAC-003-3 would ever apply to a GO who owns transmission interconnection equipment. Can the SDT provide an example or two in the Guideline and Technical Basis section of the standard?</p> <p>(2) We recommend rearranging the language in R5 of FAC-003-3 to state, "The applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments when..." This places the "shall" at the beginning of the</p>

Organization	Yes or No	Question 3 Comment
		<p>requirement which is clearer and consistent with the structure of the other requirements.</p> <p>(3) We question why there are no VSLs assigned to R4. Should there be? What are the consequences if a Regional Entity does not comply?</p> <p>(4) There does not appear to be any coordination with the Vegetation Management Standard Drafting Team (VMSDT) concerning proposed modifications to the standard. The VMSDT should be consulted.</p>
<p><b>Response:</b> Thank you for your comment.</p> <p>(1) The SDT is not currently aware of specific examples where R1 would apply, but we do not see any reason to remove that reference, as it could apply in the future. If we removed it now, we'd create a reliability gap, but if we leave it in, no Generator Owner has to take action unless it has an IROL or WECC transfer path.</p> <p>(2) This change is beyond the scope of our drafting team. It is an issue that should have been addressed under Project 2007-07. We will submit the issue in a Suggestion Form to be added to NERC's Issues Database.</p> <p>(3) Because the Regional Entity is not a Functional Entity, it cannot be assigned penalties under NERC's Reliability Standards.</p> <p>(4) The Project 2007-07 Vegetation Management drafting team's latest draft standard has already passed ballot, so coordination with that team was no longer a possibility.</p>		
APS	No	Leave the GO out of both Standards proposed.
<p><b>Response:</b> Thank you for your comment. The drafting team and the majority of stakeholder commenters support making both FAC-001 and FAC-003 applicable to Generator Owners to ensure that all Generator Owner responsibilities at the generator interconnection Facility are covered under NERC Reliability Standards. No change made.</p>		
Indeck Energy Services	No	4.3.1.3 is a regional variation. The ROP doesn't permit members of one region to vote on regional requirements for another region. A separate regional standard will be required.
<p><b>Response:</b> Thank you for your comment. It is our understanding that any stakeholder can vote on regional requirements as long as they're in the body of the standard. This does not require a separate regional standard.</p>		

Organization	Yes or No	Question 3 Comment
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP believes there should be a relaxation in the vegetation management requirements for those interconnections which only serve as a radial link to the BES. Although we fully understand the importance of keeping vegetation away from high voltage lines, the one year period is much too frequent in our generator locations. The added documentation and other expenses simply do not justify the non-existent gain in reliability when vegetation in a locale (e.g.; desert) never reaches five feet above the ground. Consider limiting this exception to units below a certain MVA rating that are not critical to the BES - perhaps coupled with evidence that vegetative intrusions are highly unlikely.
<p><b>Response:</b> Thank you for your comment. We have attempted to set up a reasonable qualifier/balance with the new one mile designation and “stake in the ground” at the fenced line of the switchyard. Because of a perceived reliability gap at the interconnection between Generator Owner Facilities and Transmission Owner Facilities, we are doing our best to apply the same Transmission Owner vegetation management requirements to the Generator Owner. This issue you raise (with respect to the vegetation in certain locales) could possibly be applied to other entities besides the Generator Owner if it was technically justified, so the drafting team encourages you to submit a SAR suggesting this.</p>		
Northeast Power Coordinating Council	No	See comments in the following questions.
EPSA	Yes	<p>EPSA generally supports the SDT’s proposed redline changes to FAC-003-X and FAC-003-3 and SDT’s diligence in monitoring Project 2007-07. There is one distinction however that EPSA would like to bring to the SDT’s attention that could increase clarity. FAC-003-X and FAC-003-3 both have similar “one half mile” language, but the starting point for the one half mile can occur one of three ways.</p> <p>In FAC-003-X, the language in 4.3.1 reads “Generator Owner that owns an overhead Facility that extends greater than one half mile beyond the fenced area of the switchyard, generating station or generating substation up to the point of interconnection with the Transmission system and ...” Therefore, there are three possible starting points for the measurement of the one half mile: beyond the fenced area of (i) the switchyard, (ii) the generating station,</p>

Organization	Yes or No	Question 3 Comment
		<p>or (iii) the generation substation. While it would appear implicit that GO's would determine which of the three was used to make the determination that the GO determines the starting point.</p> <p>Another point for consideration is that a Generator Owner's overhead Facility that is within the fence should explicitly not be applicable to the standard. EPSA believes the language that refers to the "interconnection with the Transmission system" should be changed to "interconnection with a Transmission Owner's Facility. The reason is that the term "Transmission" which is defined in the NERC Glossary could be construed to include all of a Generator Owner's interconnection leads. Therefore, we suggest that the language in 4.3.1 be modified as follows to make all of these points clear: A Generator Owner that owns an overhead Facility that extends greater than one half mile beyond the fenced area of either the generator switchyard, generating station or generating substation (as specified by the Generation Owner) up to the point of interconnection with the Transmission Owner's Facility and is operated 200 kV and above and any lower voltage lines designated by the RE as critical to the reliability of the electric system within the region is applicable to this standard."</p>
<p><b>Response:</b> Thank you for your comment. The drafting team received many comments about the half-mile qualifier in FAC-003-X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: "...that extends greater than one mile beyond the fenced area of the generating station switchyard..." We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.</p> <p>The drafting team agrees that "interconnection with a Transmission Owner's Facility" adds clarity. That change has been made.</p>		



Organization	Yes or No	Question 3 Comment
BGE	Yes	As noted in Question-1 above.
<b>Response:</b> Thank you for your comment. See our response to Question 1.		
SERC OC Standards Review Group	Yes	
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	
Electric Market Policy	Yes	
SERC Planning Standards Subcommittee	Yes	
Imperial Irrigation District (IID)	Yes	
ACES Power Members	Yes	
Bonneville Power Administration	Yes	
PacifiCorp	Yes	
Arizona Public Service Company	Yes	
Luminant Power	Yes	

Organization	Yes or No	Question 3 Comment
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Sempra Generation	Yes	
Tri-State Generation and Transmission, Inc.	Yes	
Xcel Energy	Yes	
Georgia Transmission Corporation	Yes	
Exelom	Yes	
Duke Energy	Yes	
Constellation Power Generation	Yes	
Ameren	Yes	
CHPD	Yes	
Independent Electricity System Operator	Yes	
FirstEnergy Corp	Yes	
TransAlta Centralia	Yes	

Organization	Yes or No	Question 3 Comment
Generation LLC		
LG&E and KU Energy		
Manitoba Hydro		
Tacoma Power		
Wisconsin Electric		
Utility Services, Inc.		

4. The drafting team has added Generator Owners to the Applicability sections of FAC-003-X and FAC-003-3 with the qualifier that the included lines “extend greater than one half mile beyond the fenced area of the switchyard, generating station or generating substation up to the point of interconnection with the Transmission system.” The team received many comments about the need to define a distance rather than other measures for exclusion, and decided on the one half mile as a reasonable distance. Do you agree with this half-mile qualifier?

**Summary Consideration:** The SDT thanks all individuals and groups who provided feedback. The majority of comments indicated support for the SDT’s changes to FAC-003-X and FAC-003-3, and the drafting team has made additional changes, based on commenter feedback, where they think those changes add clarity.

The drafting team received many comments about the half-mile qualifier in FAC-003-X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: “...that extends greater than one mile beyond the fenced area of the generating station switchyard...” The SDT believes that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, the team maintains that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.

One commenter suggesting including the equivalent kilometer length in the qualifying language in the standard, and we have made that change.

Organization	Yes or No	Question 4 Comment
Northeast Power Coordinating Council	No	The qualifier should be similar to that specified in Part 4.2.4 of FAC-003-3: “This standard applies to overhead transmission lines identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence. “ Vegetation needing attention can exist within a half mile of a switchyard. Vegetation does not discriminate between Generation and Transmission Owners.

**Response:** Thank you for your comment. The drafting team received many comments about the half-mile qualifier in FAC-003-

Organization	Yes or No	Question 4 Comment
		<p>X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: "...that extends greater than one mile beyond the fenced area of the generating station switchyard..." We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.</p>
<p>SPP Reliability Standards Development Team</p>	<p>No</p>	<p>See comment above. We feel like there is no need for using a distance exclusion.</p>
		<p><b>Response:</b> Thank you for your comment. The drafting team received many comments about the half-mile qualifier in FAC-003-X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: "...that extends greater than one mile beyond the fenced area of the generating station switchyard..." We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.</p>
<p>PPL Supply Group</p>	<p>No</p>	<p>Version 3 (based on V2):Comments: Although the "one half mile" is much clearer than "two spans", what is the rationale for choosing ½ mile as opposed to another length such as 1 or 2 miles? Version X (based on V1): Same as Version 3 comments</p>
		<p><b>Response:</b> Thank you for your comment. The drafting team received many comments about the half-mile qualifier in FAC-003-X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: "...that extends greater than one mile beyond the fenced area of the generating station switchyard..." We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of</p>

Organization	Yes or No	Question 4 Comment
		the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.
Bonneville Power Administration	No	BPA believes that there needs to be a clear demarcation where Transmission Owner and Generator Owner responsibilities begin and end.
		<b>Response:</b> Thank you for your comment. The drafting team is operating under the assumption the Generator Owner’s responsibilities to its interconnection Facility up to the point of interconnection with the Transmission Owner’s Facility, and we have attempted to make that clear in our draft standards. We are considering changes to the definitions of Generator Owner and Generator Operator, or creation of new terms to provide additional clarity in the next steps of our project plan, pending Standards Committee approval.
Arizona Public Service Company	No	The generator should be responsible no matter the length from fence area to the point of interconnection.
		<b>Response:</b> Thank you for your comment. The drafting team received many comments about the half-mile qualifier in FAC-003-X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: “...that extends greater than one mile beyond the fenced area of the generating station switchyard...” We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.
Southern Company	No	We agree with a one-half mile line as being “within the Generator Owner’s line of sight and could be visually monitored for vegetation conditions on a routine basis.” However, we suggest that some generation interconnection Facilities greater than ½ mile in length could also fall within the GO’s line of sight or be constructed such that they should be considered for exemption. Thus, the Task Force should consider including exclusions for longer generator tie lines if

Organization	Yes or No	Question 4 Comment
		<p>the GO can provide sufficient justification. Examples of justifications could include (1) a clear line of sight, (2) pavement, gravel, or other non-vegetation covered path, or (3) routine monitoring is performed from a roadway parallel to the line, etc. Do not obviate any other transmission requirements such as the following (which are incorporate into the draft standard): i. Operated at 200kV or higher; or ii. Operated below 200kV and included in IROL; or iii. Operated below 200kV and inclusion in a Major WECC Transfer Path</p>
<p><b>Response:</b> Thank you for your comment. The drafting team received many comments about the half-mile qualifier in FAC-003-X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: "...that extends greater than one mile beyond the fenced area of the generating station switchyard..." We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.</p> <p>The issue you raise with respect to justification for further exclusions could possibly be applied to other entities besides the Generator Owner (assuming it was technically justified), so the drafting team encourages you to submit a SAR suggesting this.</p>		
APS	No	Leave GOs out of the standards.
<p><b>Response:</b> Thank you for your comment. The drafting team and the majority of stakeholder commenters support making both FAC-001 and FAC-003 applicable to Generator Owners to ensure that all Generator Owner responsibilities at the generator interconnection Facility are covered under NERC Reliability Standards. No change made.</p>		
Ingleside Cogeneration LP	No	<p>The SDT needs to clarify that the one-half mile distance is measured from the property line of the Generation Owner, i.e., an interconnection line that is in a ROW. In addition, the half mile qualifier makes sense only for those interconnections into critical generation facilities. See our response under Question #3.</p>

Organization	Yes or No	Question 4 Comment
<p><b>Response:</b> Thank you for your comment. The drafting team received many comments about the half-mile qualifier in FAC-003-X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: "...that extends greater than one mile beyond the fenced area of the generating station switchyard..." We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.</p>		
Wisconsin Electric	No	In addition to the "greater than one-half mile" criteria, we maintain there should also be an exclusion for lines up to one mile in length which are entirely on the Generator Owner's property.
<p><b>Response:</b> Thank you for your comment. The drafting team received many comments about the half-mile qualifier in FAC-003-X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: "...that extends greater than one mile beyond the fenced area of the generating station switchyard..." We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.</p>		
Ameren	No	(1)We do not agree there should be a ½ mile exemption. On what legitimate basis could we say the first ½ mile is not important? (2) There may be different usage of the term "point of interconnection" in the industry. We suggest the SDT to consider proposing a formal definition of this term.
<p><b>Response:</b> Thank you for your comment. The drafting team received many comments about the half-mile qualifier in FAC-003-X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others</p>		



Organization	Yes or No	Question 4 Comment
<p>found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: "...that extends greater than one mile beyond the fenced area of the generating station switchyard..." We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.</p> <p>The drafting team is considering proposing a formal definition of the term "point of interconnection," or other definitional changes to make the use of that term clearer.</p>		
Westar Energy	No	
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	<p>Although the NSRF agrees with the 1/2 mile criteria (see question 1); we believe the drafting team will have to develop additional justification for this criteria given FERC's recent orders, RC11-1 and RC11-2 (see question 6 for full FERC Order details). In these orders FERC "implies" that if the GO/GOP is responsible for a breaker operated at 100kV or higher the entity should be required to register as a TOP/TO. Therefore it appears FERC would not be inclined to provide any leeway based on distance from the substation. The SDT should note that the FERC Order points to this Project to "address matters involving reliability obligations at the interface of the transmission grid", which is foot note 58.</p>
<p><b>Response:</b> Thank you for your comment.</p>		
SERC Planning Standards Subcommittee	Yes	<p>However, we are concerned that there may be a reliability gap for locations where there is not a half-mile line-of-sight from the generation switchyard.</p>
<p><b>Response:</b> Thank you for your comment. The SDT believes these cases are limited enough that an exclusion within the standard is not necessary. If you believe it is, we encourage you submit to a <a href="#">Suggestion Form</a>.</p>		
EPSA	Yes	<p>EPSA appreciates the SDT proposing to use the approach that provides a</p>

Organization	Yes or No	Question 4 Comment
		specific distance for determining which GO Facility lead lines that FAC-003 should apply to. EPSA agrees that the half-mile qualifier provides a discrete parameter that will limit ambiguity in the Standard.
<b>Response:</b> Thank you for your comment.		
LG&E and KU Energy	Yes	Although the "one half mile" is much clearer than "two spans", what is the rationale for choosing ½ mile as opposed to another length such as 1 or 2 miles?
<b>Response:</b> Thank you for your comment. The drafting team received many comments about the half-mile qualifier in FAC-003-X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: "...that extends greater than one mile beyond the fenced area of the generating station switchyard..." We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.		
Independent Electricity System Operator	Yes	We generally agree with the proposed distance. However, we suggest that in Applicability Section 4.3.1 of the two draft standards, an equivalent kilometer value be inserted after the "one half mile".
<b>Response:</b> Thank you for your comment. We have added the equivalent kilometer value.		
SERC OC Standards Review Group	Yes	While we agree, we believe that a better explanation of "the fenced area of the switchyard, generating station or generating substation up to the point of interconnection with the Transmission system" should be included. One suggestion is to distinguish between a plant perimeter fence and an internal switchyard fence.
<b>Response:</b> Thank you for your comment. The drafting team received many comments about the half-mile qualifier in FAC-		

Organization	Yes or No	Question 4 Comment
<p>003-X and FAC-003-3. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: "...that extends greater than one mile beyond the fenced area of the generating station switchyard..." We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.</p>		
BGE	Yes	1/2 mile is a distance that can generally be viewed from one location, e.g. the switchyard, and can be construed to present minimal risk since switchyards have a reasonably frequent personnel presence that could be expected to notice vegetation issues in the <1/2 mile area.
<p><b>Response:</b> Thank you for your comment.</p>		
Electric Market Policy	Yes	
Imperial Irrigation District (IID)	Yes	
Public Service Enterprise Group	Yes	
ACES Power Members	Yes	
PacifiCorp	Yes	
Luminant Power	Yes	
American Electric Power	Yes	

Organization	Yes or No	Question 4 Comment
Xcel Energy	Yes	
Sempra Generation	Yes	
Tri-State Generation and Transmission, Inc.	Yes	
BP Wind Energy North America Inc.	Yes	
Georgia Transmission Corporation	Yes	
Exelom	Yes	
FirstEnergy Corp	Yes	
TransAlta Centralia Generation LLC	Yes	
Duke Energy	Yes	
Indeck Energy Services	Yes	
Constellation Power Generation	Yes	
CHPD	Yes	
Utility Services, Inc.		
Manitoba Hydro		

<b>Organization</b>	<b>Yes or No</b>	<b>Question 4 Comment</b>
Tacoma Power		
American Transmission Company		

**5. Do you support the two year compliance timeframe for Generator Owners as included and explained in the Implementation Plans for FAC-003-X and FAC-003-3?**

**Summary Consideration:** The SDT thanks all individuals and groups who provided feedback. The vast majority of commenters supported the two-year compliance timeframe for Generator Owners as included and explained in the Implementation Plan. One commenter suggested that one year would be sufficient because most lines will be short, but the SDT pointed out that the distances of the lines can vary, and Generator Owners that have not been practicing any sort of vegetation management will need to hire new staff and develop a full vegetation management plan, which could take longer than the year given to Transmission Owners for implementation of FAC-003-1. No changes were made to the two-year compliance timeframe, although the team has modified FAC-003-3's implementation plan to account for a few different scenarios that could occur with respect to the filing of FAC-003-2 and FAC-003-3

Organization	Yes or No	Question 5 Comment
Ingleside Cogeneration LP	No	The two year compliance time frame makes sense only for those GOs who own interconnections into critical generation facilities. See our response under Question #3.
<p><b>Response:</b> Thank you for your comment. It is unclear whether you find the two year timeframe too long or too short, or if you believe that the standard should only apply to Generator Owners who own interconnections into critical generation facilities. No change made.</p> <p>Please see our response to your comments under Question 3 above.</p>		
APS	No	Leave GOs out of the standards.
<p><b>Response:</b> Thank you for your comment. The drafting team and the majority of stakeholder commenters support making both FAC-001 and FAC-003 applicable to Generator Owners to ensure that all Generator Owner responsibilities at the generator interconnection Facility are covered under NERC Reliability Standards. No change made.</p>		
Arizona Public Service Company	No	The generator should be able to be in compliance within one year since the distance of line miles is small.
<p><b>Response:</b> Thank you for your comment. The distances of the lines can vary, and Generator Owners that have not been practicing any sort of vegetation management will need to hire new staff and develop a full vegetation management plan, which could take</p>		

Organization	Yes or No	Question 5 Comment
longer than the year given to Transmission Owners for implementation of FAC-003-1. No change made.		
Northeast Power Coordinating Council	Yes	
SERC OC Standards Review Group	Yes	
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	
Electric Market Policy	Yes	
SERC Planning Standards Subcommittee	Yes	
Imperial Irrigation District (IID)	Yes	
Public Service Enterprise Group	Yes	
SPP Reliability Standards Development Team	Yes	
PPL Supply Group	Yes	
ACES Power Members	Yes	
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 5 Comment
EPSA	Yes	
PacifiCorp	Yes	
Westar Energy	Yes	
Southern Company	Yes	
Luminant Power	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Sempra Generation	Yes	
Tri-State Generation and Transmission, Inc.	Yes	
Xcel Energy	Yes	
Georgia Transmission Corporation	Yes	
BGE	Yes	No comment.
Exelom	Yes	
Wisconsin Electric	Yes	
Duke Energy	Yes	



Organization	Yes or No	Question 5 Comment
Constellation Power Generation	Yes	
Ameren	Yes	
Indeck Energy Services	Yes	
CHPD	Yes	
Independent Electricity System Operator	Yes	
FirstEnergy Corp	Yes	
TransAlta Centralia Generation LLC	Yes	
Utility Services, Inc.		
LG&E and KU Energy		
Tacoma Power		
Manitoba Hydro		
American Transmission Company		

6. In its background resource document, the drafting team lists the standards that it has not modified, and offers rationale for its decisions. Are there any reliability standards or requirements that you believe should apply to Generator Owners or Generator Operators that own and are responsible for the operation of an overhead Facility, that are not already applicable or have been proposed to be applicable (FAC-001 and FAC-003) by the Project 2010-07 drafting team? If so, please list them and offer an explanation as to why they should be applicable to that entity.

**Summary Consideration:** The SDT thanks all stakeholders for their feedback. The majority of commenters did not suggest the addition of any standards or requirements to the team’s scope of work, and a few commenters cautioned strongly against any additions. Some commenters suggested that the team consider including those standards and requirements listed in the June 2011 Cedar Creek and Milford FERC orders. The drafting team has considered the inclusion of the requirements listed in the Cedar Creek and Milford orders in the past, and has been revisiting them throughout our process. They have continued to conclude, with stakeholder support, that no additional substantive standard or requirement changes are necessary to achieve the goal of this project. With this posting, the drafting team has revisited those standards yet again and developed a comprehensive document and spreadsheet tracing their rationale (at every stage of the process) for not including additional standards or requirements. The team has elected to propose a slight clarifying change in PRC-004-2, but no changes to the applicability of that or any other standard.

While the SDT will not be adding standards at this time because they do not believe such additions are technically justified or justified by stakeholder comments, the team will be seeking some additional informal feedback from industry groups to ensure that their technical justifications are sound and supported by others outside of the drafting team. The team has posted their current draft rationale and technical justification documents on the project webpage with this posting. If you have any specific feedback on these documents, you are welcome to email [mallory.huggins@nerc.net](mailto:mallory.huggins@nerc.net).

Organization	Yes or No	Question 6 Comment
Manitoba Hydro	No	The direction of the background resource document gives special treatment to the Generator Owner in that it allows the Generator Owner TO status for a couple of standards (FAC-001 and FAC-003), but exempts the Generator Owner from many of the standards applicable to a TO. The NERC Functional Model defines the various functional entities. If a Generator Owner wants to be a TO, all the Requirements applicable to a TO should apply. There is no need to change specific Reliability Standards to allow the

Organization	Yes or No	Question 6 Comment
		Generator Owner to perform only selected TO functions.
<p><b>Response:</b> Thank you for your comment. The purpose of the drafting team is “To propose a set of changes to existing requirements and definitions, as well as additional requirements and definitions, that collectively adds significant clarity to Generator Owners and Generator Operators regarding their reliability standard obligations at the interface with the interconnected grid. This global strategy is proposed to expedite the closing of the reliability gap.” The SDT is applying select Transmission Owner standards to Generator Owners, not attempting to give them TO status.</p>		
Sempra Generation	No	No, Sempra Generation believes the Project 2010-07 Team has effectively indentified the Standards and Requirements that should apply to Generator Owners or Generator Operators that own, and are responsible for, the operation of an overhead Facility, that are not already applicable or have been proposed to be applicable.
<p><b>Response:</b> Thank you for your comment.</p>		
APS	No	Leave GOs and GOPs out of the FAC-001 and FAC-003 standards.
<p><b>Response:</b> Thank you for your comment. The drafting team and the majority of stakeholder commenters support making both FAC-001 and FAC-003 applicable to Generator Owners to ensure that all Generator Owner responsibilities at the generator interconnection Facility are covered under NERC Reliability Standards. No change made.</p>		
SERC OC Standards Review Group	No	
Electric Market Policy	No	
SERC Planning Standards Subcommittee	No	
Imperial Irrigation District (IID)	No	
SPP Reliability Standards	No	

Organization	Yes or No	Question 6 Comment
Development Team		
ACES Power Members	No	
EPSA	No	
PacifiCorp	No	
Arizona Public Service Company	No	
Westar Energy	No	
Luminant Power	No	
American Electric Power	No	
BP Wind Energy North America Inc.	No	
Tri-State Generation and Transmission, Inc.	No	
Xcel Energy	No	
Georgia Transmission Corporation	No	
BGE	No	No comment.
Exelom	No	

Organization	Yes or No	Question 6 Comment
Ingleside Cogeneration LP	No	
Wisconsin Electric	No	
Duke Energy	No	
Constellation Power Generation	No	
Ameren	No	
Indeck Energy Services	No	
CHPD	No	
Independent Electricity System Operator	No	
FirstEnergy Corp	No	
TransAlta Centralia Generation LLC	No	
Public Service Enterprise Group	Yes	<p>FERC's Cedar Creek and Milford order (issued on June 16, 2011 and that is posted at <a href="http://www.nerc.com/files/Order_Denying_Appeals_RC11-1_RC11-2_20110616.pdf">http://www.nerc.com/files/Order_Denying_Appeals_RC11-1_RC11-2_20110616.pdf</a>) listed several standards (in Paragraphs 71 and 87) that should be applicable to Cedar Creek and Milford, respectively. Because of this order, the drafting team should examine the listed standards and determine whether they are or are not applicable to Generator Owners or Generator Operators that own and are responsible for the operation of an overhead Facility. We emphasize that our recommendation takes no position on any legal issues regarding the referenced order.</p>
<p><b>Response:</b> Thank you for your comment. The drafting team has considered the inclusion of the requirements listed in the Cedar</p>		

Organization	Yes or No	Question 6 Comment
		<p>Creek and Milford orders in the past, and we have been revisiting them throughout our process. We continue to conclude, with stakeholder support, that no additional substantive standard or requirement changes are necessary to achieve the goal of this project. With this posting, the drafting team has revisited those standards yet again and developed a comprehensive document and spreadsheet tracing our rationale (at every stage of the process) for not including additional standards or requirements. We have elected to propose a slight clarifying change in PRC-004-2, but no changes to the applicability of that or any other standard. Please see the accompanying resource documents for more information.</p>
<p>Midwest Reliability Organization's NERC Standards Review Forum (NSRF)</p>	<p>Yes</p>	<p>In FERC order "Denying Appeals of Electric Reliability Organization Registration Determinations" dated June 16, 2011 (RC11-1 and RC11-2) FERC explicitly stated compliance GAPs existed with the following standards at a minimum: o FAC-011, Requirements R2, R2.1, R2.2. o PRC-001-1, Requirements R2, R2.2, R4; o PRC-004-1 Requirement R1; o TOP-004-2, Requirements R6, R6.1, R6.2, R6.3, R6.4; o PER-003-1, Requirements R1, R1.1, R1.2; o FAC-003-1, Requirements R1, R2; o TOP-001, Requirement R1 and o FAC-014-2, Requirement R2. When a GO/GOP owns transmission equipment but is not registered as a TO or TOP. The drafting team should explicitly address each of these the above requirements.</p>
<p><b>Response:</b> Thank you for your comment. The drafting team has considered the inclusion of the requirements listed in the Cedar Creek and Milford orders in the past, and we have been revisiting them throughout our process. We continue to conclude, with stakeholder support, that no additional substantive standard or requirement changes are necessary to achieve the goal of this project. With this posting, the drafting team has revisited those standards yet again and developed a comprehensive document and spreadsheet tracing our rationale (at every stage of the process) for not including additional standards or requirements. We have elected to propose a slight clarifying change in PRC-004-2, but no changes to the applicability of that or any other standard. Please see the accompanying resource documents for more information.</p>		
<p>Tacoma Power</p>	<p>Yes</p>	<p>Tacoma Power suggests that three standards be reconsidered for inclusion in this Project, to include the Generator Owner and/or Operator: EOP-005, more directly responsible for participation in restoration plans; PER-002, responsible for training; and VAR-001.</p>
<p><b>Response:</b> Thank you for your comment. We have considered the inclusion of additional standards and requirements throughout our process and we continue to conclude, with stakeholder support, that no additional substantive standard or requirement changes are necessary to achieve the goal of this project. With this posting, the drafting team has revisited those standards yet again and developed a comprehensive document and spreadsheet tracing our rationale (at every stage of the process) for not including</p>		

Organization	Yes or No	Question 6 Comment
<p>additional standards or requirements. We have elected to propose a slight clarifying change in PRC-004-2, but no changes to the applicability of that or any other standard. Please see the accompanying resource documents for more information. The SDT does not agree that VAR-001 should be applied to a GOP as VAR-002 @R2 already requires the GOP to “maintain the generator voltage or Reactive Power output (within applicable Facility Ratings) as directed by the Transmission Operator.” We believe this is sufficient in meeting the purpose of VAR-001.</p>		
Southern Company	Yes	Please see our Comments in response to Question 7.
Bonneville Power Administration	Yes	
PPL Supply Group		
Northeast Power Coordinating Council		
LG&E and KU Energy		
Utility Services, Inc.		
American Transmission Company		

**7. Do you have any other questions or concerns with the proposed standards or with the background resource document that have not been addressed? If yes, please explain.**

**Summary Consideration:** The SDT thanks all stakeholders who offered additional feedback in this section. Some comments revisited issues that had been addressed in other questions, and other comments introduced new minority concerns.

A few commenters suggested, again, the inclusion of definitions or additional standards within the scope of this project, and the SDT appreciates those comments, especially those which included detailed suggestions. While the team is not proposing any definition changes with this round of updated standard changes, they do plan to consider some definition changes or possibly new definitions to prevent future unnecessary registration of GOs and GOPs as TOs and TOPs and ensure that there are no possible reliability gaps. In the next steps of our project, we will consider putting forward definition-related changes for comment separately, following the procedure approved by the Standards Committee after its July 2011 meeting.

The SDT has also considered the inclusion of additional standards and requirements throughout our process and continues to conclude, with stakeholder support, that no additional substantive standard or requirement changes are necessary to achieve the goal of this project. With this posting, the drafting team has revisited those standards yet again and developed a comprehensive document and spreadsheet tracing our rationale (at every stage of the process) for not including additional standards or requirements. The team has elected to propose a slight clarifying change in PRC-004-2, but no changes to the applicability of that or any other standard. They have attempted to make our technical justifications much more robust and comprehensive than they were in the past, as suggested by stakeholders. Please see the accompanying resource documents (posted on the project webpage) for more information.

One commenter expressed concern about whether the SDT's work would be approved by regulators. The drafting team is doing everything we can to work with regulating entities to ensure that forced registrations no longer occur.

For most of the comments, the team made no changes and explained why:

One commenter suggested modifying the definition of Right-of-Way in the currently approved FAC-003-1 (our FAC-003-X). The team could not make any change because the definition proposed in FAC-003-3 has not been formally approved and, in general, modifications to the definition of ROW are outside the scope of our team.

One commenter suggested modifications to the format of the requirements in FAC-003-X, which the SDT determined to be outside its scope.



One commenter expressed concern about a Transmission Owner or Generator Owner having to comply with FAC-003 for a Facility that it did not own. The drafting team does not know why a Transmission Owner or Generator Owner would ever be required to provide evidence, documentation, notification, or inspection of vegetation management for Facilities not owned by that registered entity, except where explicitly agreed upon in a contract. In the absence of additional information to clarify this commenters concern, the SDT does not believe this needs to be addressed within the standard.

One commenter focused on FAC-001 and expressed concern about the “activation” point of the standard and the feasibility of any interconnection. The SDT reminded the commenter that “activation only occurs with an executed Agreement, and that in the past (for instance, 134 FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities.

One commenter wondered why only a select set of TO/TOP requirements were being applied to GOs/GOPs. The SDT directed this commenter to the goal of the team, which is to apply select Transmission Owner standards to Generator Owners, not to give them TO status.

Organization	Yes or No	Question 7 Comment
TransAlta Centralia Generation LLC	No	TransAlta Centralia Generation LLC (TransAlta) supports the recommendations put forward by the Project 2010-07 drafting team. The implementation of these recommendations will provide for much needed certainty for owners and operators of generation facilities.
<b>Response:</b> Thank you for your comment.		
SERC Planning Standards Subcommittee	No	The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
<b>Response:</b> Thank you for your comment.		
CHPD	No	
BP Wind Energy North	No	

Organization	Yes or No	Question 7 Comment
America Inc.		
Ameren	No	
Independent Electricity System Operator	No	
Tri-State Generation and Transmission, Inc.	No	
Electric Market Policy	No	
Georgia Transmission Corporation	No	
BGE	No	No comment.
Duke Energy	No	
SPP Reliability Standards Development Team	No	
Imperial Irrigation District (IID)	No	
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	No	
Xcel Energy	No	
Luminant Power	No	

Organization	Yes or No	Question 7 Comment
Wisconsin Electric	No	
ACES Power Members	No	
Arizona Public Service Company	No	
Westar Energy	No	
Bonneville Power Administration	No	
SERC OC Standards Review Group	No	
Northeast Power Coordinating Council	Yes	<p>Regarding the Right-of-Way definitions, the definition in FAC-003-3 is the better of the two. Suggest adding "and maintain" to the first sentence of the definition as follows: The corridor of land under a transmission line(s) needed to operate and maintain the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria. The term Right-of-Way goes beyond Transmission Vegetation Management, and that should be considered in the definition. How does Right-of-Way affect transmission facilities that are routed over bodies of water, or over valleys, highways, etc.? Right-of-Way in relation to underground facilities? The format of FAC-003-X should be made consistent with current NERC guidelines (i.e.--Parts of Requirements should not have R's in their numbering, should be 1.1, 1.2 etc.).</p>
<p><b>Response:</b> Thank you for your comment. It would be outside the scope of this team to modify the definition of Right-of-Way in the currently approved FAC-003-1 (our FAC-003-X), because the definition proposed in FAC-003-3 has not been formally approved and, in general, modifications to the definition of ROW are outside the scope of our team. No change made.</p>		

Organization	Yes or No	Question 7 Comment
		<p>With respect to the changes to the format of the requirements in FAC-003-X, while our drafting team is making changes to update the format of the standard where possible, we do not think it is appropriate to change the listing of the sub-requirements to parts. In earlier versions of standards, the sub-requirements were written as requirements (for instance, they have their own VSLs), and we do not believe it is appropriate within our scope to make that format and labeling change.</p>
<p>Public Service Enterprise Group</p>	<p>Yes</p>	<p>While we generally agree with the drafting team’s modifications to these standards, the team’s approach may not directly resolve the fundamental registration issue regarding a Generation Owner that only owns non-integrated interconnection transmission facilities. The non-integrated interconnection transmission facilities owned by a GO are part of the Bulk Electric System (BES) because they are part of BES generation facilities. The ownership of these non-integrated facilities should not require a GO to also register as a Transmission Owner. The draft team has proposed modifying two FAC standards that would apply to such GO-owned interconnection transmission facilities. These GO-owned interconnection transmission facilities are not, however, “integrated” transmission facilities, as the drafting team correctly points out in its background resource document. A proposed solution to the Generation Owner registration issue is discussed below.</p> <p>NERC’s Rules of Procedure (ROP) require entities to be registered in accordance with the definitions in the NERC Glossary of Terms Used in Reliability Standards (Glossary) and in accordance with the NERC Statement of Compliance Registry Criteria document. The Glossary has these definitions:</p> <ul style="list-style-type: none"> <li>o Generation Owner - Entity that owns and maintains generating units.</li> <li>o Transmission Owner - The entity that owns and maintains transmission facilities.</li> <li>o Facility - A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)</li> <li>o Transmission - An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.</li> </ul>

Organization	Yes or No	Question 7 Comment
		<p>o Transmission Service - Services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery</p> <p>The drafting team should create a new definition for the term “integrated transmission facilities” and include this new definition in the Glossary. This definition should then be use to modify the definition of Generation Owner so that registration will be clear. While the team chose not to create any new definitions, we believe the registration issue cannot be resolved without modifying the definition of “Generation Owner.”</p> <p>The following definition is proposed for Integrated Transmission Facilities in the NERC Glossary:</p> <p>o Integrated Transmission Facilities (ITF) - ITF are the Facilities that are a subpart of Transmission system that are capable of carrying the flows from multiple generator plants at different points of interconnection for delivery to customers or to other electric systems</p> <p>This proposed ITF definition builds upon FERC precedent in the Open Access Transmission Tariff (OATT) area. FERC has recognized that facilities that can carry flows from multiple supply points and deliver that power to either customers or other electric systems are proper facilities to include in an OATT and define the “Transmission System” for OATT purposes. The term “Transmission System” is an OATT-defined term that means “The facilities owned, controlled or operated by the Transmission Provider that are used to provide transmission service under Part II [Point-to-Point Transmission Service] and Part III [Network Integrated Transmission Service] of the Tariff.” Under FERC’s precedent, facilities such as generator step-up transformers and generator interconnecting transmission facilities have been excluded from the OATT; i.e., they are not facilities that provide Transmission Service because they cannot carry the flows from multiple supply points for delivery to customers or other electric system - their only use is to the Generation Owner. They perform two functions for a GO:</p> <ol style="list-style-type: none"> <li>1. They deliver power from the GO’s generators at a site to the OATT-defined Transmission System, and</li> <li>2. They deliver off-site power from the OATT-defined Transmission System to the generators at a site when the generators at a site are not operating.</li> </ol>

Organization	Yes or No	Question 7 Comment
		<p>While building on FERC OATT precedent, the proposed definition of “Integrated Transmission Facilities” does not require an applicable Transmission Service tariff to identify those facilities. Integrated Transmission Facilities are simply defined as those that capable of carrying flows from multiple supply points for delivery to customers or to other electric systems. Using the ITF definition, the definition of Generation Owner could be modified as follows:</p> <ul style="list-style-type: none"> <li>o Generation Owner - Entity that owns and maintains generating units but which does not own or maintain Integrated Transmission Facilities.</li> </ul>
<p><b>Response:</b> Thank you for your comment. We appreciate the detailed suggestions. While we are not proposing any definition changes with this round of updated standard changes, we do plan to consider some definition changes or possibly new definitions to prevent future registration and ensure that there are no possible gaps. In the next steps of our project, we will consider putting forward definition-related changes for comment separately, as is now allowed by the Standards Committee after its July 2011 meeting.</p>		
EPSA	Yes	<p>EPSA can appreciate the SDT’s decision that it not propose new defined terms for the NERC Glossary. The SDT bases the decision on outreach meetings with NERC, regional compliance managers and industry organizations. EPSA supports outreach but still believes that the SDT should propose definitions for the NERC Glossary. The definitions can serve as a basis for the outreach meetings while also further limiting reliability gaps - real or perceived. Much as EPSA expressed in its White Paper comments there is still a need for a definition for generator interconnection facilities. In addition, because integrated transmission facility has also played a big part in the cases that have prompted the need for Project 2010-07 the drafting team should propose a glossary change for that definition as well. A definition for generation interconnection facilities is necessary in Project 2010-07 Standard so that the interface between generators and transmission system can be clearly established and any ambiguities about reliability responsibilities for GOs &amp; GOPs and TO &amp; TOPs can be eliminated.</p> <p>EPSA recommended the definitions from the Ad-Hoc Group Report could be used for incorporating the Generator Interconnection Facility into the standard:</p> <ul style="list-style-type: none"> <li>Generator Interconnection Facility - Sole-use facility for the purpose of connecting the generating unit(s) to the transmission grid. In this regard, the sole-use facility</li> </ul>

Organization	Yes or No	Question 7 Comment
		<p>only transmits power associated with the interconnecting generator, whether delivered to the grid or delivered to the generator for station service or auxiliary load, or delivered to meet cogeneration load requirements.</p> <p>Generator Interconnection Operational Interface - Location at which operating responsibility for the Generator Interconnection Facility changes between the Transmission Operator and the Generator Operator.</p> <p>These definitions were developed with due consideration for varying configurations, outages, and generators materiality to the BES. The Facility definition defines the purpose of the facility, while the Generator Interconnection Operational Interface definition provides the functional lines of demarcation between the GO and the TO. The definitions were developed based on the purpose of generator interconnection facilities, their usage and how their usage differs from transmission facilities that comprise the interconnected grid. Similar to EPSA's assertions on the White Paper competitive suppliers believe this is a sound basis for distinguishing BES facilities. EPSA also suggests that the SDT include the following proposed definition for Integrated Transmission Facilities for inclusion in the NERC Glossary:</p> <p style="padding-left: 40px;">Integrated Transmission Facilities (ITF) - ITF are the Facilities that are a subpart of Transmission system that are capable of carrying the flows from multiple generator plants at different points of interconnection for delivery to customers, or to other electric systems.</p> <p>This proposed ITF definition builds upon Commission precedent in the Open Access Transmission Tariff (OATT) area. FERC has recognized that facilities that can carry flows from multiple supply points and deliver that power to either customers or other electric systems are proper facilities to include in an OATT and define the "Transmission System" for OATT purposes. The term "Transmission System" is an OATT-defined term that means "The facilities owned, controlled or operated by the Transmission Provider that are used to provide transmission service under Part II [Point-to-Point Transmission Service] and Part III [Network Integrated Transmission Service] of the Tariff." Under Commission precedent, facilities such as generator step-up transformers and generator interconnecting transmission facilities have been excluded from the OATT; i.e., they are not facilities that provide Transmission Service because they cannot carry the flows from multiple supply points for delivery to customers or other electric system - their</p>

Organization	Yes or No	Question 7 Comment
		<p>only use is to the GO and perform two functions:</p> <ol style="list-style-type: none"> <li>1. They deliver power from the GO's generators at a site to the OATT-defined Transmission System, and</li> <li>2. They deliver off-site power from the OATT-defined Transmission System to the generators at a site when the generators at a site are not operating.</li> </ol> <p>While building on FERC OATT precedent, the proposed definition of "Integrated Transmission Facilities" does not require an applicable Transmission Service tariff to identify those facilities. Integrated Transmission Facilities are simply defined as those that capable of carrying flows from multiple supply points for delivery to customers or to other electric systems. Using the ITF definition, the definition of Generation Owner could be modified as follows:</p> <p style="padding-left: 40px;">Generation Owner - The Entity that owns and maintains generating units but which does not own or maintain Integrated Transmission Facilities.</p> <p>EPSA encourages the Project 2010-07 SDT to consider fitting the above definitions into the current proposal for inclusion in the NERC Glossary. Therefore, EPSA respectfully requests that the SDT for Project 2010-07 consider the all the recommendations made herein to the seven questions.</p>
<p><b>Response:</b> Thank you for your comment. We appreciate the detailed suggestions. While we are not proposing any definition changes with this round of updated standard changes, we do plan to propose some definition changes or possibly new definitions to prevent registration and ensure that there are no possible gaps. In the next steps of our project, we will consider putting forward definition-related changes for comment separately, as is now allowed by the Standards Committee after its July 2011 meeting</p>		
PacifiCorp	Yes	<p>PacifiCorp believes the Standards Drafting Team should clarify the Transmission Owner and/or the Generator Owner are not required to provide evidence, documentation, notification, or inspection of vegetation management for facilities not owned by the Transmission Owner and/or the Generator Owner.</p>
<p><b>Response:</b> Thank you for your comment. The drafting team does not know why a Transmission Owner or Generator Owner would ever be required to provide evidence, documentation, notification, or inspection of vegetation management for Facilities not owned by that registered entity, except where explicitly agreed upon in a contract. We do not believe this needs to be addressed within the</p>		



Organization	Yes or No	Question 7 Comment
standard. No change made.		
Southern Company	Yes	<p>(1) The SDT needs to review the June 16, 2011 FERC Order on Cedar Creek and Milford and factor this into the equation. The FERC Order concludes that the Cedar Creek and Milford entities must register as a TO and TOP. In addition to FAC-003, the Cedar Creek and Milford order lists the following standards and requirements that apply to these entities as a TO/TOP:</p> <ul style="list-style-type: none"> <li>o PER-003-1, R1, R1.1, R1.2 (requiring NERC-certified transmission operators);</li> <li>o PRC-001-1, R2, R2.2, R4, R6 (notification of relay or equipment failures);</li> <li>o PRC-004-1, R1 (analyzing protection system misoperations);</li> <li>o FAC-014-2, R2 (establishment of system operating limits);</li> <li>o TOP-001, R1 (authority to take actions to alleviate operating emergencies);</li> <li>o TOP-004-2, R6, R6.1, R6.2, R6.3, R6.4 (establishment of formal policies to address voltage levels, planned outages, switching, Interconnection Reliability Operating Limits, and System Operating Limits).</li> </ul> <p>The SDT needs to address these specific requirements in sufficient detail by either revising the Project 2010-07 Background Resource Document or proposing revisions to these standards to address any reliability gaps. For example, we recommend, as a minimum, that the Background Resource Document discussion under PRC-001-1 be revised to state (underlined text added), “Generator Operators and the scope of protection equipment for generation interconnection Facilities are already appropriately accounted for in this standard in requirements R1, R2, R3, and R5.” Please note that this statement, even with our proposed revision, conflicts with the FERC Order on Cedar Creek and Milford, Paragraphs 64, 65, and 78 where FERC states that Cedar Creek and Milford must register as a TO and TOP to ensure the protection system coordination requirements in R2 and R4 of PRC-001 are met. Thus, the discussion for PRC-001-1 in the Project 2010-07 Background Resource Document needs additional language to demonstrate adequacy of the GO requirements in order to prevent GOs that own generation interconnection Facilities from having to register as a TO and TOP.</p> <p>(2) In addition, we believe the SDT should add supporting discussion to the</p>

Organization	Yes or No	Question 7 Comment
		<p>Background Resource Document to explain why the following standards adequately cover GO/GOP requirements at the Transmission Interface: PRC-004-2, PRC-005-1, PRC-023-1. For example, the Background Resource Document could state that PRC-023-1 Section A.4 Applicability already includes, "4.2. Generator Owners with load-responsive phase protection systems as described in Attachment A, applied to facilities defined in 4.1.1 through 4.1.4."</p> <p>(3) Furthermore, FERC's analysis in the Cedar Creek and Milford order suggests that reliability gaps will occur if certain entities are not registered as TO/TOP. The GRTI SAR DT should assess why its findings are different from the Commission's findings. By way of background, the GRTI SAR DT provides that its own assessment of the GOTO Ad Hoc Group Final Report concludes with a belief that there are only two standards requiring modifications to address reliability gaps - FAC-001 and FAC-003 (Background Resource Document, page 3). FERC will most likely require that NERC clearly demonstrate and provide technical support for the position that GO's only need to comply with FAC-001 and FAC-003 and not the other standards noted by FERC. The Background Resource Document does not appear to provide adequate technical support for the GRTI SAR DT position. Therefore, the GRTI SAR DT should develop that technical support in preparation for the filing of these revised standards at FERC.</p>
<p><b>Response:</b> Thank you for your comment. We have considered the inclusion of additional standards and requirements throughout our process and we continue to conclude, with stakeholder support, that no additional substantive standard or requirement changes are necessary to achieve the goal of this project. With this posting, the drafting team has revisited those standards yet again and developed a comprehensive document and spreadsheet tracing our rationale (at every stage of the process) for not including additional standards or requirements. We have elected to propose a slight clarifying change in PRC-004-2, but no changes to the applicability of that or any other standard. We have attempted to make our technical justifications much more robust and comprehensive than they were in the past, as you suggest. Please see the accompanying resource documents for more information.</p>		
APS	Yes	Leave GOs out of the standards, because it just adds more regulation and reporting requirements not needed.
<p><b>Response:</b> Thank you for your comment. The drafting team and the majority of stakeholder commenters support making both FAC-001 and FAC-003 applicable to Generator Owners to ensure that all Generator Owner responsibilities at the generator interconnection Facility are covered under NERC Reliability Standards. No change made.</p>		

Organization	Yes or No	Question 7 Comment
Sempra Generation	Yes	When implemented, the recommendations of the Project 2010-07 Team go a long way toward providing the regulatory and compliance certainty needed by generators who own or operate Generator Interconnection Facilities. NERC is encouraged to provide these industry-supported amendments to the NERC Board of Trustees in the near future. Sempra Generation also supports the comments, being concurrently filed, of the Electric Power Supply Association (EPSA).
<b>Response:</b> Thank you for your comment.		
Exelon	Yes	FAC-001-1. Exelon has generating stations that have the Main Power Transformer (MPT) disconnect as the point of demarcation. The station owns the short leads from the MPT disconnect back to the generator and the applicable TO owns from the MPT disconnect up to and including the switchyard. It is not practical for another entity to request to interconnect to the MPT disconnect nor should it be allowed. The SDT should consider verbiage to the standard that does not allow requests to interconnect to a MPT disconnect. 2. Exelon is having difficulty determining how this standard would apply to GOs and how GOs would implement the standard; suggest that examples be provided in an implementation document specifically showing where and how this standard would apply.
<b>Response:</b> Thank you for your comment.  (1) FAC-001-1 would not be “activated” simply with another entity’s request to interconnect. The standard is “activated” only with an executed Agreement to evaluate the reliability impact of interconnection. If another entity cannot interconnect to the MPT, the process should not get to the point of an executed Agreement and thus this standard would never apply.  (2) In the past (for instance, 134 FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities, and the drafting team thinks it is important to clarify the responsibilities related to such a request in NERC’s Reliability Standards by including applicable Generator Owners in FAC-001-1. We have documented our technical justification in an accompanying resource document and encourage you to review it.		
Ingleside Cogeneration LP	Yes	There is a fundamental issue related to the interconnection of generation and distribution facilities into the transmission grid. There is a myriad of complex architectures which make the designation of ownership and operational responsibilities

Organization	Yes or No	Question 7 Comment
		<p>unclear in both cases. Both this team’s efforts and those by the project team redefining the extent of the BES have run into this issue.</p> <p>Ingleside Cogeneration LP recognizes that the effort to properly assign reliability responsibilities in these gray-area connections is difficult. However, pushing the issue back to the GO/GOP by looking for them to jointly determine responsibilities with adjacent entities will create every conceivable arrangement possible.</p> <p>It seems like it should be possible to address a handful of common interconnection configurations at the start. As knowledge builds, perhaps other architectures could be added. This seems to be the direction that the project team redefining the extent of the BES is heading.</p> <p>Lastly, we need some assurance that regulators will work with us as we go down this path. Right now, the feeling is that they will continue to use forced registrations as a hammer - which may render moot this team’s efforts anyways.</p>
<p><b>Response:</b> Thank you for your comment.</p> <p>The drafting team is doing its best to coordinate with regulators to ensure that forced registrations no longer occur. While we can never be sure exactly what decision the regulators will make, our intent is to make changes through this project that prevent any future forced registrations. We have encouraged regulators to provide formal comments if they believe our changes are not going to close the gap. While there can be similarities, the SDT believes that each interconnection agreement is different. The SDT believes that each party to such agreement should have identified its ownership and operational responsibilities. If there is uncertainty as to ownership of operational responsibility of a Facility used to interconnect a generator, the respective GO/GOPs and TO/TOPs should be addressing these. Resolving these uncertainties can only occur between the affected parties.</p>		
Manitoba Hydro	Yes	<p>The direction of the background resource document gives special treatment to the Generator Owner in that it allows the Generator Owner TO status for a couple of standards (FAC-001 and FAC-003), but exempts the Generator Owner from many of the standards applicable to a TO. A Generator Owner that owns BES transmission should be held accountable for the specific Requirements and Reliability Standards applicable to the TO and Transmission Operator functions. If no other entity assumes accountability for these specific Requirements and Reliability Standards on the</p>

Organization	Yes or No	Question 7 Comment
		<p>Generator Owner BES transmission (for example system operation, protection and communication), there will be a reliability gap. Improper operation, coordination and protection of the Generator Owner BES transmission could have an impact on reliability.</p>
<p><b>Response:</b> Thank you for your comment. The purpose of the drafting team is “To propose a set of changes to existing requirements and definitions, as well as additional requirements and definitions, that collectively adds significant clarity to Generator Owners and Generator Operators regarding their reliability standard obligations at the interface with the interconnected grid. This global strategy is proposed to expedite the closing of the reliability gap.” The SDT is applying select Transmission Owner standards to Generator Owners, not attempting to give them TO status. The SDT believes that each interconnection agreement is different. The SDT believes that each party to such agreement should have identified its ownership and operational responsibilities. If there is uncertainty as to ownership of operational responsibility of a Facility used to interconnect a generator, the respective GO/GOPs and TO/TOPs should be addressing these. Resolving these uncertainties can only occur between the affected parties.</p>		
<p>Constellation Power Generation</p>	<p>Yes</p>	<p>Constellation appreciates and supports the work of the standard drafting team. We recognize the significant time invested by technical experts from industry to consider the appropriate application of reliability standards to address concerns raised about coverage of transmission at the generator interface. The recent FERC Order concerning Cedar Creek and Milford wind suggested that the list of applicable standards needing revision should go beyond FAC-001 and FAC-003.</p> <p>We appreciate the discussion and concerns raised by FERC in the order; however, the discussion is limited by failing to consider these issues in light of the full package of existing standards. Below is a look at the FERC suggested standards and how they intersect with other standards:</p> <ul style="list-style-type: none"> <li>o PRC-001-1, Requirements R2, R2.2, R4; FERC expressed concern that certain protection system components may not be well coordinated with the RC. However, the same standard (PRC-1) addresses this issue by requiring all GOs to ensure coordination of their protection system with interconnected parties. Further, FAC-002 requires that all new facilities undergo reviews by the TOP, BA, etc.</li> <li>o PRC-004-1 Requirement R1; FERC expressed concern that certain protection system components may not be analyzed for misoperations. However, the same standard (PRC-4) addresses this issue by requiring all GOs to ensure that they</li> </ul>

Organization	Yes or No	Question 7 Comment
		<p>analyze all misoperations on their protection system which would include the protection of the tie line.</p> <ul style="list-style-type: none"> <li>o TOP-004-2, Requirements R6, R6.1, R6.2, R6.3, R6.4; FERC expressed concern that coordination may be lacking between a GO and a TO with regards to the generator tie line. However, TOP standards applicable to GOs address this issue by requiring all GOs to coordinate all maintenance and emergency outages (both forced and planned) with all applicable interconnected parties. Further, all ISO procedures require the same of GOs.</li> <li>o PER-003-1, Requirements R1, R1.1, R1.2; FERC expressed concern that certain generator operators are responsible for the real time operation of the interconnected BES without being NERC certified operators, potentially causing a reliability gap. Generator Operators do not monitor and control the BES, they control and monitor generators that it operates and relays information to other operating entities. Therefore, NERC certification is not required.</li> <li>o FAC-003-1, Requirements R1, R2; FERC and the drafting team seem aligned in the need to revise this standard and the revision proposal includes such a revision.</li> <li>o TOP-001, Requirement R1; FERC expressed concern that certain tie lines may not be required to operate in such a way as to alleviate operational emergencies. However, IRO and TOP standards applicable to GOs address this issue by requiring all GOs to operate as directed by their TOP, BA, or RC as directed and must render emergency assistance.</li> <li>o FAC-014-2, Requirement R2; FERC expressed concern that certain tie lines may have a rating based on a methodology that may not be consistent with the methodology used by the RC. However, standards FAC-8 and FAC-9 address this issue by requiring all GOs to develop a methodology to rate all equipment, and that the RC has the authority to challenge the GO on that methodology. The onus is on the GO to either change their methodology and rating accordingly, or provide a technical justification as to why they cannot adopt the changes. Further, a generator will never be limited by its tie line, as a generator's profits are directly tied to its output. Therefore no generator would limit its facility to the</li> </ul>

Organization	Yes or No	Question 7 Comment
		equipment that is delivering that output.
<p><b>Response:</b> Thank you for your comment. The drafting team has considered the inclusion of the requirements listed in the Cedar Creek and Milford orders in the past, and we have been revisiting them throughout our process. We continue to conclude, with stakeholder support, that no additional substantive standard or requirement changes are necessary to achieve the goal of this project. With this posting, the drafting team has revisited those standards yet again and developed a comprehensive document and spreadsheet tracing our rationale (at every stage of the process) for not including additional standards or requirements. We appreciate the rationale you have included within your comment, and where we agree, we have incorporated it into our own.</p> <p>We have elected to propose a slight clarifying change in PRC-004-2, but no changes to the applicability of that or any other standard. Please see the accompanying resource documents for more information.</p>		
Utility Services, Inc.	Yes	<p>In one of the supporting documents for the upcoming comments, the GO/TO group included the following statement in support for the rationale on FAC-001. In its first posting for informal comment, the drafting team set the “trigger” for the application of FAC-001 as the receipt of a request for interconnection. Many commenters disagreed with this approach and suggested that the “trigger” be based upon “the intent or obligation” to interconnect a new Facility to an existing interconnecting Facility that is owned by a generator. Accordingly, the drafting team has proposed language to address this concern. The intent of this modified language is to start the compliance clock at such time as the Generator Owner executes an Agreement to perform the reliability assessment required in FAC-002-1. This step should occur whether the generator voluntarily agrees to the interconnection request or is compelled by a regulatory body to do so. In either case, we expect the Generator Owner and the requestor to execute some form of Agreement. We intentionally excluded a specific reference to the form of Agreement (such as a feasibility study) in deference to comments that we should avoid comingling of commercial and reliability aspects in reliability standards.</p> <p>I wonder about whether or not this can work timing-wise. It says the compliance clock starts with the agreement to perform the reliability assessment for FAC-002. The FAC-001 requirements outline the need for a registered entity to document, maintain, and publish facility connections requirements in order to be compliant. If the clock starts at the agreement for the assessment, does that mean that you then document, maintain, and publish the connection requirements? Don’t the connection requirements usually</p>



Organization	Yes or No	Question 7 Comment
		<p>outline the terms for the “agreement for the assessment”? I am not sure that I understand the timing sequence in order to be compliant to the standard. I would think that the agreement needs to be in place at the time of the effective date of the standard, not upon an application.</p>
<p><b>Response:</b> Thank you for your comment. We have provided a detailed explanation of how this process might look in the accompanying FAC-001-1 technical justification. Please refer to that for more information.</p>		
<p>FirstEnergy Corp</p>	<p>Yes</p>	<p>The June 16, 2011 FERC Order denying the appeals of two wind generating facilities- Cedar Creek and Milford - of the NERC determinations that Cedar Creek and Milford must each be registered as a transmission owner and transmission operator on the NERC Compliance Registry complicates the GO-TO drafting team’s work. However, the issues may be distinct and different in the end. The existing GO-TO team’s work product defines new reliability expectations for a generator owner regardless of whether or not the same entity is also being required to have a TO-TOP “light” compliance registration. In the Order, FERC describes what it believes are an appropriate limited set of TO-TOP requirements when a TO-TOP “light” registrations is deemed warranted for a traditional generation owner. The drafting team should describe what, if any, impact the FERC June 16 Order is having on its work scope.</p> <p>One minor comment for the background resource document. On page one, the last sentence of the 1st paragraph which currently reads “ ... appropriate level of reliability for the BES.” Consider changing to read “ ... Adequate Level of Reliability for the BES.” And, include a footnote directing the reader to NERC’s definition/paper describing ALR. The later references to “adequate level of reliability” within the document (i.e. page 2, 2nd paragraph could then be reduced to the acronym ALR.</p>
<p><b>Response:</b> Thank you for your comment. The drafting team has considered the inclusion of the requirements listed in the Cedar Creek and Milford orders in the past, and we have been revisiting them throughout our process. We continue to conclude, with stakeholder support, that no additional substantive standard or requirement changes are necessary to achieve the goal of this project. With this posting, the drafting team has revisited those standards yet again and developed a comprehensive document and spreadsheet tracing our rationale (at every stage of the process) for not including additional standards or requirements.</p> <p>Thank you for pointing out the opportunity to use the term “Adequate Level of Reliability.” Because NERC has appointed a task force to explore whether that definition of Adequate Level of Reliability needs to be changed, we are avoiding references to it in our latest</p>		



Organization	Yes or No	Question 7 Comment
resource document.		
PPL Supply Group	Yes	
American Wind Energy Association		<p>The American Wind Energy Association (AWEA) appreciates the opportunity to submit these formal comments on the NERC Project 2010-07. AWEA supports the general direction indicated by both the Generator Requirements at the Transmission Interface Ad Hoc Group (GOTO Ad Hoc Group), and the Project 2010-07 Standards Development Team (SDT). We agree with the sentiments from both groups that a Generator Owner (GO) or Generator Operator (GOP) that also owns or operates a generator interconnection facility (GIF), should not be required to register as a Transmission Owner (TO) and/or Transmission Operator (TOP) strictly because they own or operate the GIF. We also agree that requiring these GOs or GOPs to comply with all the TO/TOP standards would have little effect on or benefits to reliability of the Bulk Electric System.</p> <p>AWEA supports the aim of these groups to address any reliability gap that may exist with regard to GIFs by considering such facilities as part of the generating facility, and therefore also subject to the GO/GOP standards. AWEA also supports the approach of identifying a limited number of TO/TOP standards, such as FAC-001 and FAC-003, which should also apply to GIFs. We would be concerned, however, if additional requirements were added beyond these two, without serious consideration by the SDT and additional industry experts. The recent FERC order on the required registration as TOs and TOPs of two generator interconnection facilities may raise some question about the direction that the GO/TO and the SDT have taken so far on this topic. AWEA urges NERC and the SDT to use caution in considering any additional standards to apply to GIFs as the current approach of the GO/TO and SDT efforts have been generally supported. Consideration of any addition standards with respect to GIFs should be done on a standard-by-standard basis, reviewing the applicability of each standard as well as the impact on the reliability of the Bulk Electric System.</p>
<p><b>Response:</b> Thank you for your comment. The drafting team has considered the inclusion of additional standards and requirements in the past, and we have been revisiting them throughout our process. We continue to conclude, with stakeholder support, that no</p>		

Organization	Yes or No	Question 7 Comment
<p>additional substantive standard or requirement changes are necessary to achieve the goal of this project. With this posting, the drafting team has revisited those standards yet again and developed a comprehensive document and spreadsheet tracing our rationale (at every stage of the process) for not including additional standards or requirements.</p>		
<p>Cogeneration Association of California</p>		<p>The resolution of this issue regarding generator interconnection facilities should compel a certain result in determining how to classify and register generator tie-lines. Under the current standards, NERC is compelled to register owners with generator tie-lines as transmission owners. FERC has affirmed this. The changes to the standards should be such that NERC and FERC are compelled to consider the tie-lines as part of the generator facilities. The current proposal from this task force does not achieve that result. While the proposal does make very appropriate changes to certain reliability standards, it does not change the basic definition of the Bulk Electric System or change NERC's <i>Statement of Compliance Registry Criteria</i>, to determine how tie-lines are classified. Even though the relevant reliability standards would be changed so that they are also applicable to generator facilities, NERC and the regional entities will continue to apply the same definition and criteria and can continue to classify the tie-lines as Transmission.</p> <p>The solution is to change the BES definition and NERC <i>Statement</i> as well as changing the applicability of the relevant reliability standards. The background resource document from this group suggests that a change in the BES definition was part of the overall solution, but the Project 2010-17 team did not address this in its proposed definition. The concept paper from the 2010-17 group does include "generator interconnection line leads," but the formal definition paper does not.</p> <p>This project group should include in its formal proposal a change to the definition of BES, including generator interconnection facilities within the definition of generation.</p>
<p><b>Response:</b> Thank you for your comment. While we are not proposing any definition changes with this round of updated standard changes, we do plan to propose some definition changes or possibly new definitions to prevent registration and ensure that there are no possible gaps. In the next steps of our project, we will consider putting forward definition-related changes for comment separately, as is now allowed by the Standards Committee after its July 2011 meeting. Although this drafting team cannot itself make changes to the Statement of Compliance Registry Criteria, our hope is that modifications to definitions would provide the language and the impetus to make those Registry Criteria changes.</p>		

Organization	Yes or No	Question 7 Comment
<p>While the Project 2010-07 SDT coordinated with the Project 2010-17 BES SDT very early on, the Project 2010-17 SDT elected not to include any reference to generator interconnection Facilities within the definition of generation. We will consider making further suggestions during future comment periods, and you should do the same.</p>		
American Electric Power		
Tacoma Power		
Indeck Energy Services		
LG&E and KU Energy		
American Transmission Company		

END OF REPORT

## A. Introduction

1. **Title:** **Facility Connection Requirements**
2. **Number:** FAC-001-1
3. **Purpose:** To avoid adverse impacts on reliability, Transmission Owners and Generator Owners must establish Facility connection and performance requirements.
4. **Applicability:**
  - 4.1. Transmission Owner
  - 4.2. Applicable Generator Owner
    - 4.2.1 Generator Owner within an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System.
5. **Effective Date:**
  - 5.1. In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner and Regional Entity become effective upon Board of Trustees' adoption.
  - 5.2. In those jurisdictions where regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities. In those jurisdictions where no regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after Board of Trustees' adoption.

## B. Requirements

- R1. The Transmission Owner shall document, maintain, and publish Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, 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:
  - 1.1. Generation Facilities,
  - 1.2. Transmission Facilities, and
  - 1.3. End-user Facilities

*[VRF – Medium]*
- R2. Each applicable Generator Owner shall, within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System (under FAC-002-1), document and publish its Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, subregional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements.

*[VRF – Medium]*

- R3.** Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) shall address the following items in its Facility connection requirements:
- 3.1.** Provide a written summary of its plans to achieve the required system performance as described in Requirements R1 or R2 throughout the planning horizon:
    - 3.1.1.** Procedures for coordinated joint studies of new Facilities and their impacts on the interconnected Transmission Systems.
    - 3.1.2.** Procedures for notification of new or modified Facilities to others (those responsible for the reliability of the interconnected Transmission Systems) as soon as feasible.
    - 3.1.3.** Voltage level and MW and MVAR capacity or demand at point of connection.
    - 3.1.4.** Breaker duty and surge protection.
    - 3.1.5.** System protection and coordination.
    - 3.1.6.** Metering and telecommunications.
    - 3.1.7.** Grounding and safety issues.
    - 3.1.8.** Insulation and insulation coordination.
    - 3.1.9.** Voltage, Reactive Power, and power factor control.
    - 3.1.10.** Power quality impacts.
    - 3.1.11.** Equipment Ratings.
    - 3.1.12.** Synchronizing of Facilities.
    - 3.1.13.** Maintenance coordination.
    - 3.1.14.** Operational issues (abnormal frequency and voltages).
    - 3.1.15.** Inspection requirements for existing or new Facilities.
    - 3.1.16.** Communications and procedures during normal and emergency operating conditions.

*[VRF – Medium]*

- R4.** 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, the Regional Entity, and ERO on request (five business days).

*[VRF – Medium]*

## **C. Measures**

- M1.** The Transmission Owner shall make available (to its Compliance Enforcement Authority) evidence that it met all the requirements stated in Requirement R1.
- M2.** Each Generator Owner that has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System shall make available (to its Compliance Enforcement Authority) evidence that it met all requirements stated in Requirement R2.
- M3.** Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) shall make available (to its Compliance Enforcement Authority) evidence that it met all requirements stated in Requirement R3.
- M4.** The Transmission Owner shall make available (to its Compliance Enforcement Authority) evidence that it met all the requirements stated in Requirement R4.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

Compliance Monitor: Regional Entity

**1.2. Compliance Monitoring and Enforcement Processes:**

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

**1.3. Data Retention**

The Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Owner shall retain evidence of Requirement R1, Measure M1, Requirement R3, Measure M3, and Requirement R4, Measure M4 from its last audit.

The Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain evidence of Requirement R2, Measure M2, and Requirement R3, Measure M3 from its last audit.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Additional Compliance Information**

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Not Applicable.	<p>The Transmission Owner failed to do one of the following:</p> <p>Document or maintain or publish Facility connection requirements as specified in the Requirement</p> <p>OR</p> <p>Failed to include one (1) of the components as specified in R1.1, R1.2 or R1.3.</p>	<p>The Transmission Owner failed to do one of the following:</p> <p>Failed to include (2) of the components as specified in R1.1, R1.2 or R1.3</p> <p>OR</p> <p>Failed to document or maintain or publish its Facility connection requirements as specified in the Requirement <b>and</b> failed to include one (1) of the components as specified in R1.1, R1.2 or R1.3.</p>	The Transmission Owner did not develop Facility connection requirements.
R2	The Generator Owner failed to document and publish Facility connection requirements until more than 45 calendar days but less than or equal to 60 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System.	The Generator Owner failed to document and publish Facility connection requirements until more than 60 calendar days but less than or equal to 70 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System.	The Generator Owner failed to document and publish Facility connection requirements until more than 70 calendar days but less than or equal to 80 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System.	The Generator Owner failed to document and publish Facility connection requirements until more than 80 days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System.
R3	The responsible entity's Facility	The responsible entity's Facility	The responsible entity's Facility	The responsible entity's Facility

	connection requirements failed to address one of the Parts listed in Requirement R3, Part 3.1.1 R3.1.6.	connection requirements failed to address two of the Parts listed in Requirement R3, Part 3.1.1 R3.1.6.	connection requirements failed to address three of the Parts listed in Requirement R3, Part 3.1.1 R3.1.6.	connection requirements failed to address four or more of the Parts listed in Requirement R3, Part 3.1.1 R3.1.6.
R4	The responsible entity made the requirements available more than five business days but less than or equal to 10 business days after a request.	The responsible entity made the requirements available more than 10 business days but less than or equal to 20 business days after a request.	The responsible entity made the requirements available more than 20 business days less than or equal to 30 business days after a request.	The responsible entity made the requirements available more than 30 business days after a request.

**E. Regional Differences**

1. None identified.

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	TBD	Added requirements for Generator Owner and brought overall standard format up to date	Revision under Project 2010-07



The drafting team limited its modifications to those associated with expanding the scope to include the Generator Owner and bringing the format up to date.

## A. Introduction

1. **Title:** **Facility Connection Requirements**
2. **Number:** FAC-001-1
3. **Purpose:** To avoid adverse impacts on reliability, Transmission Owners and Generator Owners must establish Facility connection and performance requirements.
4. **Applicability:**
  - 4.1. Transmission Owner
  - 4.2. Applicable Generator Owner
    - 4.2.1 Generator Owner within an executed Agreement to evaluate the reliability impact of interconnecting ~~another Facility to its existing generation Facility~~ a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System.
5. **Effective Date:**
  - 5.1. In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner and Regional Entity become effective upon Board of Trustees' adoption.
  - 5.2. In those jurisdictions where regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities. In those jurisdictions where no regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after Board of Trustees' adoption.

## B. Requirements

- R1. The Transmission Owner shall document, maintain, and publish Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, 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:
  - 1.1. Generation Facilities,
  - 1.2. Transmission Facilities, and
  - 1.3. End-user Facilities

*[VRF – Medium]*
- R2. Each applicable Generator Owner shall, within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System ~~of executing an Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility~~ (under FAC-002-1), ~~shall~~ document and publish its and thereafter maintain Facility connection requirements to ensure compliance with NERC Reliability

Standards and applicable Regional Entity, subregional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements.

*[VRF – Medium]*

**R3.** Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) with Facility connection requirements and each Transmission Owner shall ~~have Facility connection requirements that~~ address the following items in its Facility connection requirements:

- 3.1.** Provide a written summary of its plans to achieve the required system performance as described in Requirements R1 ~~and or~~ R2 throughout the planning horizon:
  - 3.1.1.** Procedures for coordinated joint studies of new Facilities and their impacts on the interconnected Transmission Systems.
  - 3.1.2.** Procedures for notification of new or modified Facilities to others (those responsible for the reliability of the interconnected Transmission Systems) as soon as feasible.
  - 3.1.3.** Voltage level and MW and MVAR capacity or demand at point of connection.
  - 3.1.4.** Breaker duty and surge protection.
  - 3.1.5.** System ~~p~~Protection and coordination.
  - 3.1.6.** Metering and telecommunications.
  - 3.1.7.** Grounding and safety issues.
  - 3.1.8.** Insulation and insulation coordination.
  - 3.1.9.** Voltage, Reactive Power, and power factor control.
  - 3.1.10.** Power quality impacts.
  - 3.1.11.** Equipment Ratings.
  - 3.1.12.** Synchronizing of Facilities.
  - 3.1.13.** Maintenance coordination.
  - 3.1.14.** Operational issues (abnormal frequency and voltages).
  - 3.1.15.** Inspection requirements for existing or new Facilities.
  - 3.1.16.** Communications and procedures during normal and emergency operating conditions.

*[VRF – Medium]*

**R4.** ~~The Transmission Owner shall Each applicable Generator Owner with Facility connection requirements (in accordance with Requirement R2) and each Transmission Owner shall maintain Facility connection requirements and~~ maintain and update its Facility connection

~~requirements as required. The Transmission Owner shall~~ make documentation of these requirements available to the users of the ~~t~~Transmission ~~s~~System, the Regional Entity, and ERO on request (five business days).

*[VRF – Medium]*

### C. Measures

**M1.** The Transmission Owner shall make available (to its Compliance Enforcement Authority) evidence that it met all the requirements stated in Requirement R1.

**M2.** Each Generator Owner ~~that has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System that executes an Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility~~ shall make available (to its Compliance Enforcement Authority) evidence that it met all requirements stated in Requirement R2.

**M3.** ~~Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) Each applicable Generator Owner with Facility connection requirements and each Transmission Owner~~ shall make available (to its Compliance Enforcement Authority) evidence that it met all requirements stated in Requirement R3.

**M4.** ~~Each applicable Generator Owner with Facility connection requirements and each~~The Transmission Owner shall make available (to its Compliance Enforcement Authority) evidence that it met all the requirements stated in Requirement R4.

### D. Compliance

#### 1. Compliance Monitoring Process

##### 1.1. Compliance Enforcement Authority

Compliance Monitor: Regional Entity

##### 1.2. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

##### 1.3. Data Retention

The Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Owner shall retain evidence of Requirement R1, Measure M1, Requirement R3, Measure M3, and Requirement R4, Measure M4 from its last audit.

The Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain evidence of Requirement R2, Measure M2, and Requirement R3, Measure M3, ~~and Requirement R4, Measure M4~~ from its last audit.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Additional Compliance Information**

None.

**2. Violation Severity Levels**

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Not Applicable.	<p>The Transmission Owner failed to do one of the following:</p> <p>Document or maintain or publish Facility connection requirements as specified in the Requirement</p> <p>OR</p> <p>Failed to include one (1) of the components <del>and as</del> specified in R1.1, R1.2 or R1.3.</p>	<p>The Transmission Owner failed to do one of the following:</p> <p><del>Document or maintain or publish its Facility connection requirements as specified in the Requirement</del></p> <p>OR</p> <p>Failed to include (2) of the components as specified in R1.1, R1.2 or R1.3</p> <p>OR</p> <p>Failed to document or maintain or publish its Facility connection requirements as specified in the Requirement <b>and</b> failed to include one (1) of the components as specified in R1.1, R1.2 or R1.3.</p>	<p>The Transmission Owner did not develop Facility connection requirements.</p>

R2	<p>The <del>responsible entity</del> <u>Generator Owner</u> failed to document and publish <del>and thereafter maintain</del> Facility connection requirements until more than 45 calendar days but less than or equal to 60 calendar days after <u>having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System.</u> <del>executing an Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility.</del></p>	<p>The <u>Generator Owner</u> <del>responsible entity</del> failed to document and publish <del>and thereafter maintain</del> Facility connection requirements until more than 60 calendar days but less than or equal to 70 calendar days after <u>having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System.</u> <del>executing an Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility.</del></p>	<p>The <u>Generator Owner</u> <del>responsible entity</del> failed to document and publish <del>and thereafter maintain</del> Facility connection requirements until more than 70 calendar days but less than or equal to 80 calendar days after <u>having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System.</u> <del>executing an Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility.</del></p>	<p>The <u>Generator Owner</u> <del>responsible entity</del> failed to document and publish <del>and thereafter maintain</del> Facility connection requirements until more than 80 days after <u>having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System.</u> <del>executing an Agreement to evaluate the reliability impact of interconnecting another Facility to its existing generation Facility.</del></p>
R3	<p>The responsible entity's Facility connection requirements failed to address one of the <u>Parts listed in Requirement R3, Part 3.1.1 R3.1.6subrequirements.</u></p>	<p>The responsible entity's Facility connection requirements failed to address two of the <u>Parts listed in Requirement R3, Part 3.1.1 R3.1.6subrequirements.</u></p>	<p>The responsible entity's Facility connection requirements failed to address three of the <u>Parts listed in Requirement R3, Part 3.1.1 R3.1.6subrequirements.</u></p>	<p>The responsible entity's Facility connection requirements failed to address four or more of the <u>Parts listed in Requirement R3, Part 3.1.1 R3.1.6subrequirements.</u></p> <p><b>OR</b></p> <p><del>The responsible entity does not have Facility connection requirements.</del></p>
R4	<p>The responsible entity made the requirements available more than</p>	<p>The responsible entity made the requirements available more than 10</p>	<p>The responsible entity made the requirements available more than 20</p>	<p>The responsible entity made the requirements</p>

	five business days but less than or equal to 10 business days after a request.	business days but less than or equal to 20 business days after a request.	business days less than or equal to 30 business days after a request.	available more than 30 business days after a request.
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**E. Regional Differences**

1. None identified.

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	TBD	Added requirements for Generator Owner and brought overall standard format up to date	Revision under Project 2010-07

## A. Introduction

1. **Title:** Facility Connection Requirements
2. **Number:** FAC-001-~~01~~
3. **Purpose:** To avoid adverse impacts on reliability, Transmission Owners and Generator Owners must establish Facility connection and performance requirements.
4. **Applicability:**
  - 4.1. Transmission Owner
  - 4.2. Applicable Generator Owner
    - 4.2.1 Generator Owner within an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System.
5. **Effective Date:** ~~April 1, 2005~~
  - 5.1. In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner and Regional Entity become effective upon Board of Trustees' adoption.
  - 5.2. In those jurisdictions where regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities. In those jurisdictions where no regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after Board of Trustees' adoption.

## 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~~Entity, 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:

- 1.1. Generation Facilities,
- 1.2. Transmission Facilities, and
- 1.3. End-user Facilities

*[VRF – Medium]*

**R2.** Each applicable Generator Owner shall, within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission Owner's System (under FAC-002-1), document and publish its Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, subregional,

Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements.

[VRF – Medium]

**R3.** Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) shall address, but are not limited to, the following items: in its Facility connection requirements:

- 3.1.** Provide a written summary of its plans to achieve the required system performance as described ~~above~~ in Requirements R1 or R2 throughout the planning horizon:
  - 3.1.1.** Procedures for coordinated joint studies of new Facilities and their impacts on the interconnected Transmission Systems.
  - 3.1.2.** Procedures for notification of new or modified Facilities to others (those responsible for the reliability of the interconnected Transmission Systems) as soon as feasible.
  - 3.1.3.** Voltage level and MW and MVAR capacity or demand at point of connection.
  - 3.1.4.** Breaker duty and surge protection.
  - 3.1.5.** System protection and coordination.
  - 3.1.6.** Metering and telecommunications.
  - 3.1.7.** Grounding and safety issues.
  - 3.1.8.** Insulation and insulation coordination.
  - 3.1.9.** Voltage, Reactive Power, and power factor control.
  - 3.1.10.** Power quality impacts.
  - 3.1.11.** Equipment Ratings.
  - 3.1.12.** Synchronizing of Facilities.
  - 3.1.13.** Maintenance coordination.
  - 3.1.14.** Operational issues (abnormal frequency and voltages).
  - 3.1.15.** Inspection requirements for existing or new Facilities.
  - 3.1.16.** Communications and procedures during normal and emergency operating conditions.

[VRF – Medium]

**R4.** 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, the Regional ~~Reliability Organization~~ Entity, and ~~NERC~~ERO on request (five business days).

*[VRF – Medium]*

## C. Measures

- M1.** The Transmission Owner shall make available (to its Compliance ~~Monitor~~) ~~for inspection~~ Enforcement Authority) evidence that it met all the requirements stated in ~~Reliability Standard FAC-001-0-Requirement~~ R1.
- M2.** ~~Each Generator Owner that has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to~~ the Transmission ~~Owner~~ System shall make available (to its Compliance ~~Monitor~~) ~~for inspection~~ Enforcement Authority) evidence that it met all requirements stated in ~~Reliability Standard FAC-001-0-Requirement~~ R2.
- M3.** ~~The~~ Each Transmission Owner ~~and each applicable Generator Owner (in accordance with Requirement R2)~~ shall make available (to its Compliance ~~Monitor~~) ~~for inspection~~ Enforcement Authority) evidence that it met all ~~the~~ requirements stated in ~~Reliability Standard FAC-001-0-R3~~ Requirement R3.
- M3.M4.** ~~The~~ Transmission Owner shall make available (to its Compliance Enforcement Authority) evidence that it met all the requirements stated in Requirement R4.

## D. Compliance

### 1. Compliance Monitoring Process

- 1.1. Compliance ~~Monitoring Responsibility~~ Enforcement Authority**  
Compliance Monitor: Regional ~~Reliability Organization~~ Entity
- 1.2. Compliance Monitoring ~~Period~~ and ~~Reset Timeframe~~ Enforcement Processes:**  
~~On request (five business days):~~  
Compliance Audits  
Self-Certifications  
Spot Checking  
Compliance Violation Investigations  
Self-Reporting  
Complaints
- 1.3. Data Retention**  
~~None specified.~~  
The Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Owner shall retain evidence of Requirement R1, Measure M1, Requirement R3, Measure M3, and Requirement R4, Measure M4 from its last audit.

The Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain evidence of Requirement R2, Measure M2, and Requirement R3, Measure M3 from its last audit.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Additional Compliance Information**

None.

**2. Violation Severity 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.~~

<u>R #</u>	<u>Lower VSL</u>	<u>Moderate VSL</u>	<u>High VSL</u>	<u>Severe VSL</u>
<u>R1</u>	<u>Not Applicable.</u>	<u>The Transmission Owner failed to do one of the following:</u>  <u>Document or maintain or publish Facility connection requirements as specified in the Requirement</u>	<u>The Transmission Owner failed to do one of the following:</u>  <u>Failed to include (2) of the components as specified in R1.1, R1.2 or R1.3</u>  <u>OR</u>	<u>The Transmission Owner did not develop Facility connection requirements.</u>

		<p><u>OR</u></p> <p><u>Failed to include one (1) of the components as specified in R1.1, R1.2 or R1.3.</u></p>	<p><u>Failed to document or maintain or publish its Facility connection requirements as specified in the Requirement and failed to include one (1) of the components as specified in R1.1, R1.2 or R1.3.</u></p>	
<u>R2</u>	<p><u>The Generator Owner failed to document and publish Facility connection requirements until more than 45 calendar days but less than or equal to 60 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System.</u></p>	<p><u>The Generator Owner failed to document and publish Facility connection requirements until more than 60 calendar days but less than or equal to 70 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System.</u></p>	<p><u>The Generator Owner failed to document and publish Facility connection requirements until more than 70 calendar days but less than or equal to 80 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System.</u></p>	<p><u>The Generator Owner failed to document and publish Facility connection requirements until more than 80 days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System.</u></p>
<u>R3</u>	<p><u>The responsible entity's Facility connection requirements failed to address one of the Parts listed in Requirement R3, Part 3.1.1 R3.1.6.</u></p>	<p><u>The responsible entity's Facility connection requirements failed to address two of the Parts listed in Requirement R3, Part 3.1.1 R3.1.6.</u></p>	<p><u>The responsible entity's Facility connection requirements failed to address three of the Parts listed in Requirement R3, Part 3.1.1 R3.1.6.</u></p>	<p><u>The responsible entity's Facility connection requirements failed to address four or more of the Parts listed in Requirement R3, Part 3.1.1 R3.1.6.</u></p>
<u>R4</u>	<p><u>The responsible entity made the requirements available more than five business days but less than or equal to 10 business days after a request.</u></p>	<p><u>The responsible entity made the requirements available more than 10 business days but less than or equal to 20 business days after a request.</u></p>	<p><u>The responsible entity made the requirements available more than 20 business days less than or equal to 30 business days after a request.</u></p>	<p><u>The responsible entity made the requirements available more than 30 business days after a request.</u></p>

E. **Regional Differences**

1. None identified.

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
<u>1</u>	<u>TBD</u>	<u>Added requirements for Generator Owner and brought overall standard format up to date</u>	<u>Revision under Project 2010-07</u>

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary. When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.*

### **Right-of-Way (ROW)**

A corridor of land on which electric lines may be located. The applicable Transmission Owner or applicable Generator Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

The current glossary definition of this NERC term was modified to include applicable Generator Owners.

FAC-003-2 is currently under development under Project 2007-07. The project is nearing its final stages, but the Project 2010-07 drafting team does not want to assume that the project will be approved by NERC's Board or Trustees (BOT) or FERC. Thus, the Project 2010-07 drafting team has developed two sets of proposed changes: one to this version, FAC-003-1, the current FERC-approved version of the standard, and one to FAC-003-2, the latest draft of Version 2 as proposed by the Project 2007-07 team

If FAC-003-2 is approved by NERC's BOT, the Project 2010-07 drafting team will likely proceed with the modifications it has proposed in the redline to that version of the standard. These changes would be submitted for stakeholder approval and balloted as FAC-003-3. FAC-003-2 would be retired once FAC-003-3 was approved.

If, however, FAC-003-2 remains under development, the Project 2010-07 drafting team will proceed with the changes to FAC-003-1 seen below to avoid further delay of its project goals. Changes to FAC-003-1 would address the addition of Generator Owners to the applicability section, modifications to the NERC defined terms Right-of-Way to include Generator Owners, and some formatting changes to bring the standard up to date. These changes would not be comprehensive; rather, they would aim to include the generator interconnection Facility in the standard with as few other changes as possible.

## **A. Introduction**

**1. Title: Transmission Vegetation Management Program**

**2. Number: FAC-003-X**

**3. Purpose:** To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation-related outages of the transmission systems to the respective Regional Entity (RE) and the North American Electric Reliability Council (NERC).

Within the text of NERC Reliability Standard FAC-003-X, "transmission line(s)" and "applicable line(s)" can also refer to the generation Facilities as referenced in 4.4 and its subsections.

### **4. Applicability:**

**4.1. Regional Entity.**

**4.2. Applicable Transmission Owner**

**4.2.1. Transmission Owner that owns overhead transmission lines operated at 200 kV and above and to any lower voltage lines designated by the RE as critical to the reliability of the electric system in the region.**

**4.3. Applicable Generator Owner**

**4.3.1. Generator Owner that owns an overhead transmission line(s) that extends greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard up to the point of interconnection with a Transmission Owner's Facility and is operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.**

### **5. Effective Dates:**

There are three effective dates associated with this implementation plan:

The first effective date applies to Transmission Owners.

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner become effective upon Board of Trustees' adoption.

The second effective date allows Generator Owners time to prepare a formal transmission vegetation management program as outlined in Requirement R1.

In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The third effective date allows entities time to comply with Requirements R2, R3, and R4.

In those jurisdictions where regulatory approval is required, Requirements R2, R3, and R4 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R2, R3, and R4 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

## **B. Requirements**

**R1.** Each applicable Transmission Owner or applicable Generator Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the applicable Transmission Owner's or applicable Generator Owner's objectives, practices, approved procedures, and work specifications<sup>1</sup>.

**R1.1.** The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the applicable Transmission Owner's or applicable Generator Owner's transmission lines.

**R1.2.** Each applicable Transmission Owner or applicable Generator Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the applicable Transmission Owner or applicable Generator Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.

**R1.2.1.** Clearance 1 — The applicable Transmission Owner or applicable Generator Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the applicable

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<sup>1</sup> ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.

Transmission Owner or applicable Generator Owner plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.

**R1.2.2.** Clearance 2 — The applicable Transmission Owner or applicable Generator Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These applicable Transmission Owner-specific or applicable Generator Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.

**R1.2.2.1** Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.

**R1.2.2.2** Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.

**R1.3.** All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner or Generator Owner, to perform their duties.

**R1.4.** Each applicable Transmission Owner or applicable Generator Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner or applicable Generator Owner is restricted from attaining the clearances specified in Requirement 1.2.1.

**R1.5.** Each Transmission Owner or applicable Generator Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.

[VRF – High]

**R2.** Each applicable Transmission Owner or applicable Generator Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or



regulatory authorities. Each applicable Transmission Owner or applicable Generator Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.

*[VRF – High]*

- R3.** Each applicable Transmission Owner or applicable Generator Owner shall report quarterly to its Regional Entity, or the Regional Entity’s designee, sustained transmission line outages determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation.
- R3.1.** Multiple sustained 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.
- R3.2.** The applicable Transmission Owner or applicable Generator Owner is not required to report to the Regional Entity, or the Regional Entity’s designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).
- R3.3.** The outage information provided by the applicable Transmission Owner or applicable Generator Owner to the Regional Entity, or the Regional Entity’s designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.
- R3.4.** An outage shall be categorized as one of the following:
- R3.4.1.** Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;
  - R3.4.2.** Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;
  - R3.4.3.** Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.

*[VRF – Lower]*

- R4.** The Regional Entity shall report the outage information provided to it by applicable Transmission Owners or applicable Generator Owners, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported outages.

*[VRF – Lower]*

**C. Measures**

- M1.** Each applicable Transmission Owner or applicable Generator Owner has a documented TVMP, as identified in Requirement 1.
  - M1.1.** Each applicable Transmission Owner or applicable Generator Owner has documentation that the applicable Transmission Owner or applicable Generator Owner performed the vegetation inspections as identified in Requirement 1.1.
  - M1.2.** Each applicable Transmission Owner or applicable Generator Owner has documentation that describes the clearances identified in Requirement 1.2.
  - M1.3.** Each applicable Transmission Owner or applicable Generator Owner has documentation that the personnel directly involved in the design and implementation of the applicable Transmission Owner’s or applicable Generator Owner TVMP hold the qualifications identified by the Transmission Owner or applicable Generator Owner as required in Requirement 1.3.
  - M1.4.** Each applicable Transmission Owner or applicable Generator Owner has documentation that it has identified any areas not meeting the applicable Transmission Owner’s or applicable Generator Owner’s standard for vegetation management and any mitigating measures the Transmission Owner or applicable Generator Owner has taken to address these deficiencies as identified in Requirement 1.4.
  - M1.5.** Each applicable Transmission Owner or applicable Generator Owner has a documented process for the immediate communication of imminent threats by vegetation as identified in Requirement 1.5.
- M2.** Each applicable Transmission Owner or applicable Generator Owner has documentation that the Transmission Owner implemented the work plan identified in Requirement 2.
- M3.** Each applicable Transmission Owner or applicable Generator Owner has documentation that it has supplied quarterly outage reports to the Regional Entity, or the Regional Entity’s designee, as identified in Requirement 3.
- M4.** The Regional Entity has documentation that it provided quarterly outage reports to NERC as identified in Requirement 4.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

Compliance Monitor:

- Regional Entity for the Transmission Owner and Generator Owner
- Electric Reliability Organization or another Regional Entity approved by the ERO and FERC or other applicable government authorities

**1.2. Compliance Monitoring and Enforcement Processes:**

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

**1.3. Data Retention**

The applicable Transmission Owner and applicable Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The applicable Transmission Owner and applicable Generator Owner shall retain evidence of Requirement 1, Measure 1, Requirement 2, Measure 2, and Requirement 3, Measure 3 from its last audit.

**1.4. Additional Compliance Information**

None.

**2. Violation Severity Levels**

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity did not include and keep current one of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current two of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current three of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current all required elements of the TVMP, as directed by the requirement.
R1.1	N/A	N/A	The applicable entity TVMP did not define a schedule, as directed by the requirement, or the type of ROW vegetation inspections, as directed by the requirement.	The applicable entity TVMP did not define a schedule, as directed by the requirement, nor the type of ROW vegetation inspections, as directed by the requirement.
R1.2	N/A	N/A	N/A	The responsible entity, in its TVMP, failed to identify and document clearances between vegetation and any overhead, ungrounded supply conductors.  OR  The responsible entity, in its

				<p>TVMP, failed to take into consideration transmission line voltage, or the effects of ambient temperature on conductor sag under maximum design loading, or the effects of wind velocities on conductor sway.</p> <p>OR</p> <p>The responsible entity, in its TVMP, failed to establish Clearance 1 or Clearance 2 values.</p>
R1.2.1	N/A	N/A	N/A	<p>The responsible entity failed to determine and document an appropriate clearance distance to be achieved at the time of transmission vegetation management work taking into account local conditions and the expected time frame in which the responsible entity expects to return for future vegetation management work.</p> <p>OR</p> <p>The responsible entity documented a Clearance 1 value that was smaller than its</p>

				Clearance 2 value.
R1.2.2	N/A	N/A	N/A	The responsible entity failed to determine and document Clearance 2 values taking into account local conditions and the expected time frame in which the responsible entity expects to return for future vegetation management work.
R1.2.2.1	N/A	N/A	N/A	Where transmission system transient overvoltage factors were known, clearances were not derived from Table 5, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.
R1.2.2.2	N/A	N/A	N/A	Where transmission system transient overvoltage factors are known, clearances were not derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.
R1.3	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, one of those persons did not hold appropriate	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, two of those persons did not hold appropriate	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, three of those persons did not hold appropriate	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, more than three of those persons did not hold appropriate

	qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, 5% or less of those persons did not hold appropriate qualifications and training to perform their duties.	qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 5% up to (and including) 10% of those persons did not hold appropriate qualifications and training to perform their duties.	qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 10% up to (and including) 15% of those persons did not hold appropriate qualifications and training to perform their duties.	qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 15% of those persons did not hold appropriate qualifications and training to perform their duties.
R1.4	N/A	N/A	N/A	The responsible entity's TVMP does not include mitigation measures to achieve sufficient clearances where restrictions to the ROW are in effect.
R1.5	N/A	N/A	N/A	The responsible entity did not establish or did not document a process for the immediate communication of vegetation conditions that present an imminent threat of line outage, as directed by the requirement.
R2	The responsible entity did not meet one of the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of	The responsible entity did not meet two of the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of	The responsible entity did not meet the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of	The responsible entity does not have an annual plan for vegetation management.  OR  The responsible entity has not implemented the annual plan for

	adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	vegetation management.
R3	<p>The responsible entity failed to provide a quarterly outage report, but did not experience any reportable outages.</p> <p>OR</p> <p>The responsible entity provided a quarterly report, but failed to report in the manner specified by one or more of the following subcomponents of Requirement R3: R3.1 or R3.2.</p>	<p>The responsible entity provided a quarterly report, but failed to include information required by R3.3.</p>	<p>The responsible entity provided a quarterly outage report, but failed to include a reportable Category 3 outage as described in R3.4.3.</p>	<p>The responsible entity experienced reportable outages but failed to provide a quarterly report.</p> <p>OR</p> <p>The responsible entity provided a quarterly outage report, but failed to include a reportable Category 1 (as described in R3.4.1) or Category 2 outage (as described in R3.4.2).</p>
R4	N/A	N/A	N/A	N/A

**E. Regional Differences**

None Identified.

**Version History**

Version	Date	Action	Change Tracking
1	TBA	<ol style="list-style-type: none"> <li>1. Added “Standard Development Roadmap.”</li> <li>2. Changed “60” to “Sixty” in section A, 5.2.</li> <li>3. Added “Proposed Effective Date: April 7, 2006” to footer.</li> <li>4. Added “Draft 3: November 17, 2005” to</li> </ol>	01/20/06

**Standard FAC-003-X — Transmission Vegetation Management Program**

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		footer.	
X	May 16, 2011	Made standard applicable to certain qualifying Generator Owners and brought overall standard format up to date	Revision under Project 2010-07



## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary. When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.*

### **Right-of-Way (ROW)**

A corridor of land on which electric lines may be located. The applicable Transmission Owner or applicable Generator Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

The current glossary definition of this NERC term was modified to include applicable Generator Owners.

FAC-003-2 is currently under development under Project 2007-07. The project is nearing its final stages, but the Project 2010-07 drafting team does not want to assume that the project will be approved by NERC's Board or Trustees (BOT) or FERC. Thus, the Project 2010-07 drafting team has developed two sets of proposed changes: one to this version, FAC-003-1, the current FERC-approved version of the standard, and one to FAC-003-2, the latest draft of Version 2 as proposed by the Project 2007-07 team

If FAC-003-2 is approved by NERC's BOT, the Project 2010-07 drafting team will likely proceed with the modifications it has proposed in the redline to that version of the standard. These changes would be submitted for stakeholder approval and balloted as FAC-003-3. FAC-003-2 would be retired once FAC-003-3 was approved.

If, however, FAC-003-2 remains under development, the Project 2010-07 drafting team will proceed with the changes to FAC-003-1 seen below to avoid further delay of its project goals. Changes to FAC-003-1 would address the addition of Generator Owners to the applicability section, modifications to the NERC defined terms Right-of-Way to include Generator Owners, and some formatting changes to bring the standard up to date. These changes would not be comprehensive; rather, they would aim to include the generator interconnection Facility in the standard with as few other changes as possible.

## A. Introduction

1. **Title:** Transmission Vegetation Management Program

2. **Number:** FAC-003-X

3. **Purpose:** To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation-related outages of the transmission systems to the respective Regional Entity (RE) and the North American Electric Reliability Council (NERC).

Within the text of NERC Reliability Standard FAC-003-X, "transmission line(s)" and "applicable line(s)" can also refer to the generation Facilities as referenced in 4.4 and its subsections.

4. **Applicability:**

4.1. Regional Entity.

4.2. Applicable Transmission Owner

4.2.1. Transmission Owner that owns overhead transmission lines operated at 200 kV and above and to any lower voltage lines designated by the RE as critical to the reliability of the electric system in the region.

4.3. Applicable Generator Owner

4.3.1. Generator Owner that owns an overhead ~~Facility~~ transmission line(s) that extends greater than one ~~half~~ or 1.609 kilometers beyond the fenced area of the ~~switchyard, generating station or generating substation~~ generating station switchyard up to the point of interconnection with ~~the Transmission system~~ Transmission Owner's Facility and is operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.

5. **Effective Dates:**

There are three effective dates associated with this implementation plan:

The first effective date applies to Transmission Owners.

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner become effective upon Board of Trustees' adoption.

The second effective date allows Generator Owners time to prepare a formal transmission vegetation management program as outlined in Requirement R1.

In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The third effective date allows entities time to comply with Requirements R2, R3, and R4.

In those jurisdictions where regulatory approval is required, Requirements R2, R3, and R4 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R2, R3, and R4 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

## **B. Requirements**

**R1.** Each applicable Transmission Owner or applicable Generator Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the applicable Transmission Owner's or applicable Generator Owner's objectives, practices, approved procedures, and work specifications<sup>1</sup>.

**R1.1.** The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the applicable Transmission Owner's or applicable Generator Owner's transmission lines.

**R1.2.** Each applicable Transmission Owner or applicable Generator Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the applicable Transmission Owner or applicable Generator Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.

**R1.2.1.** Clearance 1 — The applicable Transmission Owner or applicable Generator Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon

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<sup>1</sup> ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.

local conditions and the expected time frame in which the applicable Transmission Owner or applicable Generator Owner plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.

**R1.2.2.** Clearance 2 — The applicable Transmission Owner or applicable Generator Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These applicable Transmission Owner-specific or applicable Generator Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.

**R1.2.2.1** Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.

**R1.2.2.2** Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.

**R1.3.** All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner or Generator Owner, to perform their duties.

**R1.4.** Each applicable Transmission Owner or applicable Generator Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner or applicable Generator Owner is restricted from attaining the clearances specified in Requirement 1.2.1.

**R1.5.** Each Transmission Owner or applicable Generator Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.

[VRF – High]

**R2.** Each applicable Transmission Owner or applicable Generator Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into

consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each applicable Transmission Owner or applicable Generator Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.

*[VRF – High]*

**R3.** Each applicable Transmission Owner or applicable Generator Owner shall report quarterly to its Regional Entity, or the Regional Entity's designee, sustained transmission line outages determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation.

**R3.1.** Multiple sustained 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.

**R3.2.** The applicable Transmission Owner or applicable Generator Owner is not required to report to the Regional Entity, or the Regional Entity's designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).

**R3.3.** The outage information provided by the applicable Transmission Owner or applicable Generator Owner to the Regional Entity, or the Regional Entity's designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

**R3.4.** An outage shall be categorized as one of the following:

**R3.4.1.** Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;

**R3.4.2.** Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;

**R3.4.3.** Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.

*[VRF – Lower]*

**R4.** The Regional Entity shall report the outage information provided to it by applicable Transmission Owners or applicable Generator Owners, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported outages.

*[VRF – Lower]*

## C. Measures

- M1.** Each applicable Transmission Owner or applicable Generator Owner has a documented TVMP, as identified in Requirement 1.
- M1.1.** Each applicable Transmission Owner or applicable Generator Owner has documentation that the applicable Transmission Owner or applicable Generator Owner performed the vegetation inspections as identified in Requirement 1.1.
- M1.2.** Each applicable Transmission Owner or applicable Generator Owner has documentation that describes the clearances identified in Requirement 1.2.
- M1.3.** Each applicable Transmission Owner or applicable Generator Owner has documentation that the personnel directly involved in the design and implementation of the applicable Transmission Owner's or applicable Generator Owner TVMP hold the qualifications identified by the Transmission Owner or applicable Generator Owner as required in Requirement 1.3.
- M1.4.** Each applicable Transmission Owner or applicable Generator Owner has documentation that it has identified any areas not meeting the applicable Transmission Owner's or applicable Generator Owner's standard for vegetation management and any mitigating measures the Transmission Owner or applicable Generator Owner has taken to address these deficiencies as identified in Requirement 1.4.
- M1.5.** Each applicable Transmission Owner or applicable Generator Owner has a documented process for the immediate communication of imminent threats by vegetation as identified in Requirement 1.5.
- M2.** Each applicable Transmission Owner or applicable Generator Owner has documentation that the Transmission Owner implemented the work plan identified in Requirement 2.
- M3.** Each applicable Transmission Owner or applicable Generator Owner has documentation that it has supplied quarterly outage reports to the Regional Entity, or the Regional Entity's designee, as identified in Requirement 3.
- M4.** The Regional Entity has documentation that it provided quarterly outage reports to NERC as identified in Requirement 4.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

Compliance Monitor:

- Regional Entity for the Transmission Owner and Generator Owner
- Electric Reliability Organization or another Regional Entity for the Regional Entity approved by the ERO and FERC or other applicable government authorities

**1.2. Compliance Monitoring and Enforcement Processes:**

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

**1.3. Data Retention**

The applicable Transmission Owner and applicable Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The applicable Transmission Owner and applicable Generator Owner shall retain evidence of Requirement 1, Measure 1, Requirement 2, Measure 2, and Requirement 3, Measure 3 from its last audit.

**1.4. Additional Compliance Information**

None.

**2. Violation Severity Levels**

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity did not include and keep current one of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current two of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current three of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current all required elements of the TVMP, as directed by the requirement.
R1.1	N/A	N/A	The applicable entity TVMP did not define a schedule, as directed by the requirement, or the type of ROW vegetation inspections, as directed by the requirement.	The applicable entity TVMP did not define a schedule, as directed by the requirement, nor the type of ROW vegetation inspections, as directed by the requirement.
R1.2	N/A	N/A	N/A	The responsible entity, in its TVMP, failed to identify and document clearances between vegetation and any overhead, ungrounded supply conductors.  OR  The responsible



				<p>entity, in its TVMP, failed to take into consideration transmission line voltage, or the effects of ambient temperature on conductor sag under maximum design loading, or the effects of wind velocities on conductor sway.</p> <p>OR</p> <p>The responsible entity, in its TVMP, failed to establish Clearance 1 or Clearance 2 values.</p>
R1.2.1	N/A	N/A	N/A	<p>The responsible entity failed to determine and document an appropriate clearance distance to be achieved at the time of transmission vegetation management work taking into account local conditions and the expected time frame in which the responsible entity expects to return for future vegetation management work.</p> <p>OR</p> <p>The responsible entity documented a Clearance 1 value that was</p>



				smaller than its Clearance 2 value.
R1.2.2	N/A	N/A	N/A	The responsible entity failed to determine and document Clearance 2 values taking into account local conditions and the expected time frame in which the responsible entity expects to return for future vegetation management work.
R1.2.2.1	N/A	N/A	N/A	Where transmission system transient overvoltage factors were known, clearances were not derived from Table 5, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.
R1.2.2.2	N/A	N/A	N/A	Where transmission system transient overvoltage factors are known, clearances were not derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.
R1.3	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, one of those persons did not hold	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, two of those persons did not hold	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, three of those persons did not hold	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, more than three of those persons did not

	appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, 5% or less of those persons did not hold appropriate qualifications and training to perform their duties.	appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 5% up to (and including) 10% of those persons did not hold appropriate qualifications and training to perform their duties.	appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 10% up to (and including) 15% of those persons did not hold appropriate qualifications and training to perform their duties.	hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 15% of those persons did not hold appropriate qualifications and training to perform their duties.
R1.4	N/A	N/A	N/A	The responsible entity's TVMP does not include mitigation measures to achieve sufficient clearances where restrictions to the ROW are in effect.
R1.5	N/A	N/A	N/A	The responsible entity did not establish or did not document a process for the immediate communication of vegetation conditions that present an imminent threat of line outage, as directed by the requirement.
R2	The responsible entity did not meet one of the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining	The responsible entity did not meet two of the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining	The responsible entity did not meet the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining	The responsible entity does not have an annual plan for vegetation management.  OR  The responsible entity has not implemented the

	documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	annual plan for vegetation management.
R3	<p>The responsible entity failed to provide a quarterly outage report, but did not experience any reportable outages.</p> <p>OR</p> <p>The responsible entity provided a quarterly report, but failed to report in the manner specified by one or more of the following subcomponents of Requirement R3: R3.1 or R3.2.</p>	<p>The responsible entity provided a quarterly report, but failed to include information required by R3.3.</p>	<p>The responsible entity provided a quarterly outage report, but failed to include a reportable Category 3 outage as described in R3.4.3.</p>	<p>The responsible entity experienced reportable outages but failed to provide a quarterly report.</p> <p>OR</p> <p>The responsible entity provided a quarterly outage report, but failed to include a reportable Category 1 (as described in R3.4.1) or Category 2 outage (as described in R3.4.2).</p>
R4	N/A	N/A	N/A	N/A

**E. Regional Differences**

None Identified.

**Version History**

Version	Date	Action	Change Tracking
1	TBA	<ol style="list-style-type: none"> <li>Added “Standard Development Roadmap.”</li> <li>Changed “60” to “Sixty” in section A, 5.2.</li> <li>Added “Proposed Effective Date: April 7, 2006” to footer.</li> </ol>	01/20/06

**Standard FAC-003-X — Transmission Vegetation Management Program**

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		4. Added “Draft 3: November 17, 2005” to footer.	
X	May 16, 2011	<del>Added</del> <u>Made standard applicable to certain qualifying requirements for</u> Generator Owners and brought overall standard format up to date	Revision under Project 2010-07

### Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary. When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.*

#### **Right-of-Way (ROW)**

A corridor of land on which electric lines may be located. The applicable Transmission Owner or applicable Generator Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

The current glossary definition of this NERC term was modified to include applicable Generator Owners.

FAC-003-2 is currently under development under Project 2007-07. The project is nearing its final stages, but the Project 2010-07 drafting team does not want to assume that the project will be approved by NERC’s Board or Trustees (BOT) or FERC. Thus, the Project 2010-07 drafting team has develop two sets of proposed changes: one to this version, FAC-003-1, the current FERC-approved version of the standard, and one to FAC-003-2, the latest draft of Version 2 as proposed by the Project 2007-07 team

If FAC-003-2 is approved by NERC’s BOT, the Project 2010-07 drafting team will likely proceed with the modifications it has proposed in the redline to that version of the standard. These changes would be submitted for stakeholder approval and balloted as FAC-003-3. FAC-003-2 would be retired once FAC-003-03 was approved.

If, however, FAC-003-2 remains under development, the Project 2010-07 drafting team will proceed with the changes to FAC-003-1 seen below to avoid further delay of its project goals. Changes to FAC-003-1 would address the addition of Generator Owners to the applicability section, modifications to the NERC defined terms Right-of-Way to include Generator Owners, and some formatting changes to bring the standard up to date. These changes would not be comprehensive; rather, they would aim to include the generator interconnection Facility in the standard with as few other changes as possible.

**A. Introduction**

**1. Title: Transmission Vegetation Management Program**

**2. Number: FAC-003-~~1X~~**

**3. Purpose:** To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation-related outages of the transmission systems to the respective Regional ~~Reliability Organizations (RRO)~~Entity (RE) and the North American Electric Reliability Council (NERC).

Within the text of NERC Reliability Standard FAC-003-X, “transmission line(s)” and “applicable line(s)” can also refer to the generation Facilities as referenced in 4.4 and its subsections.

**4. Applicability:**

**4.1. Regional Entity.**

**4.1.4.2. Applicable Transmission Owner-**

**4.2. Regional Reliability Organization-**

**4.2.1. This standard shall apply to all Transmission Owner that owns overhead transmission lines operated at 200 kV and above and to any lower voltage lines designated by the ~~RRO~~RE as critical to the reliability of the electric system in the region.**

**4.3. Applicable Generator Owner**

**4.3.1. Generator Owner that owns an overhead transmission line(s) that extends greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard up to the point of interconnection with the a Transmission Owner’s Facility and is operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.**

5. **Effective Dates:**

~~5.1. One calendar year from the date of adoption by the NERC Board of Trustees for Requirements 1 and 2.~~

~~5.2. Sixty calendar days from the date of adoption by the NERC Board of Trustees for Requirements 3 and 4.~~

**B. Requirements**

~~The Transmission~~ There are three effective dates associated with this implementation plan:

The first effective date applies to Transmission Owners.

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner become effective upon Board of Trustees' adoption.

The second effective date allows Generator Owners time to prepare a formal transmission vegetation management program as outlined in Requirement R1.

In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The third effective date allows entities time to comply with Requirements R2, R3, and R4.

In those jurisdictions where regulatory approval is required, Requirements R2, R3, and R4 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R2, R3, and R4 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

**B. Requirements**

**R1.** Each applicable Transmission Owner or applicable Generator Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the applicable Transmission Owner's or applicable Generator Owner's objectives, practices, approved procedures, and work specifications<sup>1</sup>.

**R1.1.** The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the applicable Transmission Owner's or applicable Generator Owner's transmission lines.

**R1.2.** ~~The~~Each applicable Transmission Owner or applicable Generator Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the

<sup>1</sup> ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.

effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the applicable Transmission Owner or applicable Generator Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.

**R1.2.1.** Clearance 1 — The applicable Transmission Owner or applicable Generator Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the applicable Transmission Owner or applicable Generator Owner plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.

**R1.2.2.** Clearance 2 — The applicable Transmission Owner or applicable Generator Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These applicable Transmission Owner-specific or applicable Generator Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.

**R1.2.2.1** Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.

**R1.2.2.2** Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.

**R1.3.** All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner or Generator Owner, to perform their duties.

**R1.4.** Each applicable Transmission Owner or applicable Generator Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner or applicable Generator Owner is restricted from attaining the clearances specified in Requirement 1.2.1.

**R1.5.** Each Transmission Owner or applicable Generator Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action



(temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.

~~The~~[VRF – High]

- R2.** Each applicable Transmission Owner or applicable Generator Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each applicable Transmission Owner or applicable Generator Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.

~~The~~[VRF – High]

- R3.** Each applicable Transmission Owner or applicable Generator Owner shall report quarterly to its ~~RRO~~Regional Entity, or the ~~RRO's~~Regional Entity's designee, sustained transmission line outages determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation.
- R3.1.** Multiple sustained 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.
- R3.2.** The applicable Transmission Owner or applicable Generator Owner is not required to report to the ~~RRO~~Regional Entity, or the ~~RRO's~~Regional Entity's designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).
- R3.3.** The outage information provided by the applicable Transmission Owner or applicable Generator Owner to the ~~RRO~~Regional Entity, or the ~~RRO's~~Regional Entity's designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.
- R3.4.** An outage shall be categorized as one of the following:
- R3.4.1.** Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;

**R3.4.2.** Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;

**R3.4.3.** Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.

*[VRF – Lower]*

**R4.** The ~~RRO~~Regional Entity shall report the outage information provided to it by applicable Transmission ~~Owner's~~Owners or applicable Generator Owners, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the ~~RRO~~Regional Entity as a result of any of the reported outages.

*[VRF – Lower]*

## C. Measures

**M1.** ~~The~~Each applicable Transmission Owner or applicable Generator Owner has a documented TVMP, as identified in Requirement 1.

**M1.1.** ~~The~~Each applicable Transmission Owner or applicable Generator Owner has documentation that the applicable Transmission Owner or applicable Generator Owner performed the vegetation inspections as identified in Requirement 1.1.

**M1.2.** ~~The~~Each applicable Transmission Owner or applicable Generator Owner has documentation that describes the clearances identified in Requirement 1.2.

**M1.3.** ~~The~~Each applicable Transmission Owner or applicable Generator Owner has documentation that the personnel directly involved in the design and implementation of the applicable Transmission Owner's or applicable Generator Owner TVMP hold the qualifications identified by the Transmission Owner or applicable Generator Owner as required in Requirement 1.3.

**M1.4.** ~~The~~Each applicable Transmission Owner or applicable Generator Owner has documentation that it has identified any areas not meeting the applicable Transmission Owner's or applicable Generator Owner's standard for vegetation management and any mitigating measures the Transmission Owner or applicable Generator Owner has taken to address these deficiencies as identified in Requirement 1.4.

**M1.5.** ~~The~~Each applicable Transmission Owner or applicable Generator Owner has a documented process for the immediate communication of imminent threats by vegetation as identified in Requirement 1.5.

**M2.** ~~The~~Each applicable Transmission Owner or applicable Generator Owner has documentation that the Transmission Owner implemented the work plan identified in Requirement 2.

**M3.** ~~The~~Each applicable Transmission Owner or applicable Generator Owner has documentation that it has supplied quarterly outage reports to the ~~RRO~~Regional Entity, or the ~~RRO's~~Regional Entity's designee, as identified in Requirement 3.

**M4.** The ~~RRO~~Regional Entity has documentation that it provided quarterly outage reports to NERC as identified in Requirement 4.

## D. Compliance

### 1. Compliance Monitoring Process

**1.1.** ~~Compliance~~ ~~Monitoring Responsibility~~ ~~Enforcement Authority~~

~~RRO~~

~~NERC~~

~~6 of 13~~ ~~Adopted by NERC Board of Trustees: February 7, 2006~~

~~Effective Date: April 7, 2006~~

~~Draft 2: August 31, 2011~~

~~of~~

Compliance Monitor:

- Regional Entity for the Transmission Owner and Generator Owner
- Electric Reliability Organization or another Regional Entity approved by the ERO and FERC or other applicable government authorities

**1.2. Compliance Monitoring ~~Period~~ and ~~Reset~~ Enforcement Processes:**

~~One calendar Year~~

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

**1.3. Data Retention**

~~Five Years~~

The applicable Transmission Owner and applicable Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The applicable Transmission Owner and applicable Generator Owner shall retain evidence of Requirement 1, Measure 1, Requirement 2, Measure 2, and Requirement 3, Measure 3 from its last audit.

**1.4. Additional Compliance Information**

~~The Transmission Owner shall demonstrate compliance through self-certification submitted to the compliance monitor (RRO) annually that it meets the requirements of NERC Reliability Standard FAC-003-1. The compliance monitor shall conduct an on-site audit every five years or more frequently as deemed appropriate by the compliance monitor to review documentation related to Reliability Standard FAC-003-1. Field audits of ROW vegetation conditions may be conducted if determined to be necessary by the compliance monitor.~~

None.

**2. Violation Severity Levels of Non-Compliance**

**~~2.1. Level 1:~~**

~~2.1.1. The TVMP was incomplete in one of the requirements specified in any subpart of Requirement 1, or;~~

~~2.1.2. Documentation of the annual work plan, as specified in Requirement 2, was incomplete when presented to the Compliance Monitor during an on-site audit, or;~~

~~2.1.3. The RRO provided an outage report to NERC that was incomplete and did not contain the information required in Requirement 4.~~

**~~2.2. Level 2:~~**

~~2.2.1. The TVMP was incomplete in two of the requirements specified in any subpart of Requirement 1, or;~~

~~2.2.2. The Transmission Owner was unable to certify during its annual self-certification that it fully implemented its annual work plan, or documented deviations from, as specified in Requirement 2.~~

~~2.2.3. The Transmission Owner reported one Category 2 transmission vegetation-related outage in a calendar year.~~

~~2.3. Level 3: ———~~

~~2.3.1. The Transmission Owner reported one Category 1 or multiple Category 2 transmission vegetation related outages in a calendar year, or;~~

~~2.3.2. The Transmission Owner did not maintain a set of clearances (Clearance 2), as defined in Requirement 1.2.2, to prevent flashover between vegetation and overhead ungrounded supply conductors, or;~~

~~2.3.3. The TVMP was incomplete in three of the requirements specified in any subpart of Requirement 1.~~

~~2.4. Level 4: —~~

~~2.4.1. The Transmission Owner reported more than one Category 1 transmission vegetation related outage in a calendar year, or;~~

~~2.4.2. The TVMP was incomplete in four or more of the requirements specified in any subpart of Requirement 1.~~

<u>R #</u>	<u>Lower VSL</u>	<u>Moderate VSL</u>	<u>High VSL</u>	<u>Severe VSL</u>
<u>R1</u>	<u>The responsible entity did not include and keep current one of the four required elements of its TVMP, as directed by the requirement.</u>	<u>The responsible entity did not include and keep current two of the four required elements of its TVMP, as directed by the requirement.</u>	<u>The responsible entity did not include and keep current three of the four required elements of its TVMP, as directed by the requirement.</u>	<u>The responsible entity did not include and keep current all required elements of the TVMP, as directed by the requirement.</u>
<u>R1.1</u>	<u>N/A</u>	<u>N/A</u>	<u>The applicable entity TVMP did not define a schedule, as directed by the requirement, or the type of ROW vegetation inspections, as directed by the requirement.</u>	<u>The applicable entity TVMP did not define a schedule, as directed by the requirement, nor the type of ROW vegetation inspections, as directed by the requirement.</u>
<u>R1.2</u>	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	<u>The responsible entity, in its TVMP, failed to</u>

				<p><u>identify and document clearances between vegetation and any overhead, ungrounded supply conductors.</u></p> <p><u>OR</u></p> <p><u>The responsible entity, in its TVMP, failed to take into consideration transmission line voltage, or the effects of ambient temperature on conductor sag under maximum design loading, or the effects of wind velocities on conductor sway.</u></p> <p><u>OR</u></p> <p><u>The responsible entity, in its TVMP, failed to establish Clearance 1 or Clearance 2 values.</u></p>
<u>R1.2.1</u>	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	<p><u>The responsible entity failed to determine and document an appropriate clearance distance to be achieved at the time of transmission vegetation management work taking into account local conditions and the expected time frame in</u></p>

				<p><u>which the responsible entity expects to return for future vegetation management work.</u></p> <p><u>OR</u></p> <p><u>The responsible entity documented a Clearance 1 value that was smaller than its Clearance 2 value.</u></p>
<u>R1.2.2</u>	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	<p><u>The responsible entity failed to determine and document Clearance 2 values taking into account local conditions and the expected time frame in which the responsible entity expects to return for future vegetation management work.</u></p>
<u>R1.2.2.1</u>	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	<p><u>Where transmission system transient overvoltage factors were known, clearances were not derived from Table 5, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.</u></p>
<u>R1.2.2.2</u>	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	<p><u>Where transmission system transient overvoltage factors are known, clearances were not derived from Table 7, IEEE</u></p>

				<u>516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.</u>
<u>R1.3</u>	<u>For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, one of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, 5% or less of those persons did not hold appropriate qualifications and training to perform their duties.</u>	<u>For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, two of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 5% up to (and including) 10% of those persons did not hold appropriate qualifications and training to perform their duties.</u>	<u>For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, three of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 10% up to (and including) 15% of those persons did not hold appropriate qualifications and training to perform their duties.</u>	<u>For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, more than three of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 15% of those persons did not hold appropriate qualifications and training to perform their duties.</u>
<u>R1.4</u>	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	<u>The responsible entity's TVMP does not include mitigation measures to achieve sufficient clearances where restrictions to the ROW are in effect.</u>
<u>R1.5</u>	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	<u>The responsible entity did not establish or did not document a process for the immediate communication of vegetation conditions that present an</u>

				<u>imminent threat of line outage, as directed by the requirement.</u>
<u>R2</u>	<u>The responsible entity did not meet one of the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.</u>	<u>The responsible entity did not meet two of the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.</u>	<u>The responsible entity did not meet the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.</u>	<u>The responsible entity does not have an annual plan for vegetation management.</u>  <u>OR</u>  <u>The responsible entity has not implemented the annual plan for vegetation management.</u>
<u>R3</u>	<u>The responsible entity failed to provide a quarterly outage report, but did not experience any reportable outages.</u>  <u>OR</u>  <u>The responsible entity provided a quarterly report, but failed to report in the manner specified by one or more of the following subcomponents of Requirement R3: R3.1 or R3.2.</u>	<u>The responsible entity provided a quarterly report, but failed to include information required by R3.3.</u>	<u>The responsible entity provided a quarterly outage report, but failed to include a reportable Category 3 outage as described in R3.4.3.</u>	<u>The responsible entity experienced reportable outages but failed to provide a quarterly report.</u>  <u>OR</u>  <u>The responsible entity provided a quarterly outage report, but failed to include a reportable Category 1 (as described in R3.4.1) or Category 2 outage (as described in R3.4.2).</u>
<u>R4</u>	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>



E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
1	TBA	<ol style="list-style-type: none"> <li>1. Added “Standard Development Roadmap.”</li> <li>2. Changed “60” to “Sixty” in section A, 5.2.</li> <li>3. Added “Proposed Effective Date: April 7, 2006” to footer.</li> <li>4. Added “Draft 3: November 17, 2005” to footer.</li> </ol>	01/20/06
<u>X</u>	<u>May 16, 2011</u>	<u>Made standard applicable to certain qualifying Generator Owners and brought overall standard format up to date</u>	<u>Revision under Project 2010-07</u>

## Effective Dates

There are two effective dates associated with this standard.

The first effective date allows Generator Owners time to develop documented maintenance strategies or procedures or processes or specifications as outlined in Requirement R3.

In those jurisdictions where regulatory approval is required, Requirement R3 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The second effective date allows entities time to comply with Requirements R1, R2, R4, R5, R6, and R7.

In those jurisdictions where regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.
2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.
3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.

4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.
5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

Version History

<b>Version</b>	<b>Date</b>	<b>Action</b>	<b>Change Tracking</b>
3	September 29, 2011	Using the latest draft of FAC-003-2 from the Project 2007-07 SDT, modified proposed definitions and Applicability to include Generator Owners of a certain length.	Revision under Project 2010-07

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

### **Right-of-Way (ROW)**

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria.

The current glossary definition of this NERC term is modified to address the issues set forth in Paragraph 734 of FERC Order 693.

### **Vegetation Inspection**

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the applicable Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.

Current definition of Vegetation Inspection:  
The systematic examination of a transmission corridor to document vegetation conditions.

### **Minimum Vegetation Clearance Distance (MVCD)**

The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

*When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.*

FAC-003-2 is currently under development under Project 2007-07. The project is nearing its final stages, but the Project 2010-07 drafting team does not want to assume that the project will be approved by NERC’s Board or Trustees (BOT) or FERC. Thus, the Project 2010-07 drafting team has developed two sets of proposed changes: one to this version, the latest draft of Version 2 as proposed by the Project 2007-07 team, and one to FAC-003-1, the current FERC-approved version of the standard.

If FAC-003-2 is approved by NERC’s BOT, the Project 2010-07 drafting team will likely proceed with the modifications seen in this standard. These changes would be submitted for stakeholder approval and balloted as FAC-003-3. Several scenarios that could play out based on the order of the approval of these versions of the standards are addressed in the FAC-003-3 implementation plan.

If, however, FAC-003-2 remains under development, the Project 2010-07 drafting team will proceed with changes to FAC-003-1 to avoid further delay of its project goals. Changes to FAC-003-1 would address the addition of Generator Owners to the applicability, the proposal of modifications to the NERC defined term Right-of-Way to include applicable Generator Owners, and some formatting changes to bring the standard up to date. These changes would not be comprehensive; rather, they would aim to include the generator interconnection Facility in the standard with as few other changes as possible.

## A. Introduction

1. **Title:** Transmission Vegetation Management
2. **Number:** FAC-003-3
3. **Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.
4. **Applicability**
  - 4.1. **Functional Entities:**
    - 4.1.1. Applicable Transmission Owners
      - 4.1.1.1. Transmission Owners that own Transmission Facilities defined in 4.2.
    - 4.1.2. Applicable Generator Owners

**4.1.2.1.** Generator Owners that own generation Facilities defined in 4.3

**4.2. Transmission Facilities:** Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal<sup>1</sup>, state, provincial, public, private, or tribal entities:

**4.2.1.** Each overhead transmission line operated at 200kV or higher.

**4.2.2.** Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.

**4.2.3.** Each overhead transmission line operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

**4.2.4.** Each overhead transmission line identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

**4.3. Generation Facilities:** Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal<sup>2</sup>, state, provincial, public, private, or tribal entities:

**4.3.1.** Overhead transmission lines that extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating switchyard and are:

**4.3.1.1.** Operated at 200kV or higher; or

**4.3.1.2.** Operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.

**4.3.1.3.** Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

**Rationale:** The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

Within the text of NERC Reliability Standard FAC-003-3, “transmission line(s) and “applicable line(s) can also refer to the generation Facilities as referenced in 4.3 and its subsections.

Enforcement:

<sup>1</sup> EPAAct 2005 section 1211c: “Access approvals by Federal agencies.”

<sup>2</sup> EPAAct 2005 section 1211c: “Access approvals by Federal agencies.”

The Requirements within a Reliability Standard govern and will be enforced. The Requirements within a Reliability Standard define what an entity must do to be compliant and binds an entity to certain obligations of performance under Section 215 of the Federal Power Act. Compliance will in all cases be measured by determining whether a party met or failed to meet the Reliability Standard Requirement given the specific facts and circumstances of its use, ownership or operation of the bulk power system.

Measures provide guidance on assessing non-compliance with the Requirements. Measures are the evidence that could be presented to demonstrate compliance with a Reliability Standard Requirement and are not intended to contain the quantitative metrics for determining satisfactory performance nor to limit how an entity may demonstrate compliance if valid alternatives to demonstrating compliance are available in a specific case. A Reliability Standard may be enforced in the absence of specified Measures.

Entities must comply with the “Compliance” section in its entirety, including the Administrative Procedure that sets forth, among other things, reporting requirements.

The “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” are provided for informational purposes. They are designed to convey guidance from NERC’s various activities. The “Guideline and Technical Basis” section and text boxes with “Examples” and “Rationale” are not intended to establish new Requirements under NERC’s Reliability Standards or to modify the Requirements in any existing NERC Reliability Standard. Implementation of the “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” is not a substitute for compliance with Requirements in NERC’s Reliability Standards.”

## **5. Background:**

- 5.1.1.** This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:
- 5.1.2.** a) Performance-based — defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome?*
- 5.1.3.** b) Risk-based — preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?*
- 5.1.4.** c) Competency-based — defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should



be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?*

- 5.1.5.** The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

**5.1.6.** For this standard, the requirements have been developed as follows:

**5.1.7.** Performance-based: Requirements 1 and 2

**5.1.8.** Competency-based: Requirement 3

**5.1.9.** Risk-based: Requirements 4, 5, 6 and 7

**5.1.10.** R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

- 5.1.11.** Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term “public lands” includes municipal lands, village lands, city lands, and a host of other governmental entities.
- 5.1.12.** This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.
- 5.1.13.** This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.
- 5.1.14.** Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

## B. Requirements and Measures

**R1.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below<sup>3</sup> [*Violation Risk Factor: High*] [*Time Horizon: Real-time*]:

1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage<sup>4</sup>,
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage<sup>5</sup>,
3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage<sup>4</sup>,
4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage<sup>4</sup>.

**M1.** Each applicable Transmission Owner

### Rationale for R1 and R2:

Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable Transmission Owner's or applicable Generator Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.
2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

<sup>3</sup> This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.

<sup>4</sup> If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

<sup>5</sup> Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

**R2.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below<sup>2</sup> [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time*]:

1. An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage<sup>3</sup>,
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage<sup>4</sup>,
3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage<sup>4</sup>,
4. An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage<sup>4</sup>

**M2.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)

**R3.** Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following:

**3.1** Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;

**3.2** Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]:

**Rationale**

The documentation provides a basis for evaluating the competency of the applicable Transmission Owner’s or applicable Generator Owner’s vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions. See Figure

**M3.** The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

**R4.** Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment [Violation Risk Factor: Medium] [Time Horizon: Real-time].

**Rationale**

This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

**M4.** Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

**R5.** When a applicable Transmission Owner and applicable Generator Owner is constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

**Rationale**

Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

**M5.** Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

**R6.** Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW<sup>6</sup> [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

**Rationale**

Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could

<sup>6</sup> When the applicable Transmission Owner or applicable Generator Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.

**M6.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

**R7.** Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan

**Rationale**

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

(measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

- Change in expected growth rate/ environmental factors
- Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner<sup>7</sup>
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Emerging technologies

**M7.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of

<sup>7</sup> Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.

acceptable forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records.  
(R7)



## C. Compliance

### 1. Compliance Monitoring Process

#### 1.1 Compliance Enforcement Authority

#### 1.2 Regional Entity Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, Measures M1, M2, M3, M5, M6 and M7 for three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.3 Compliance Monitoring and Enforcement Processes:

5.1.15. Compliance Audit

5.1.16. Self-Certification

5.1.17. Spot Checking

5.1.18. Compliance Violation Investigation

5.1.19. Self-Reporting

Complaint

Periodic Data Submittal

#### 1.4 Additional Compliance Information

***Periodic Data Submittal:*** The applicable Transmission Owner and applicable Generator Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

**Table of Compliance Elements**

R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Real-time	High	The responsible entity failed to manage vegetation in a manner such that the responsible entity had an encroachment into the MVCD observed in Real-time, absent a Sustained Outage.	The responsible entity failed to manage vegetation in a manner such that the responsible entity had an encroachment into the MVCD due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage.	The responsible entity failed to manage vegetation in a manner such that the responsible entity had an encroachment into the MVCD due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage.	The responsible entity failed to manage vegetation in a manner such that the responsible entity had an encroachment into the MVCD due to a grow-in that caused a vegetation-related Sustained Outage.
R2	Real-time	Medium	The responsible entity failed to manage vegetation in a manner such that the responsible entity had an encroachment into the MVCD observed in Real-time, absent a Sustained Outage.	The responsible entity failed to manage vegetation in a manner such that the responsible entity had an encroachment into the MVCD due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage.	The responsible entity failed to manage vegetation in a manner such that the responsible entity had an encroachment into the MVCD due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage.	The responsible entity failed to manage vegetation in a manner such that the responsible entity had an encroachment into the MVCD due to a grow-in that caused a vegetation-related Sustained Outage.
R3	Long-Term Planning	Lower		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity’s applicable lines. (Requirement R3, Part 3.2)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity’s applicable lines. Requirement R3, Part 3.1)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity’s applicable lines.

R4	Real-time	Medium			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5	Operations Planning	Medium				The responsible entity did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6	Operations Planning	Medium	The responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7	Operations Planning	Medium	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Differences

None.

E. Interpretations

None.

F. Associated Documents

Guideline and Technical Basis (attached).

## Guideline and Technical Basis

### Effective dates:

The first two sentences of the Effective Dates section is standard language used in most NERC standards to cover the general effective date and is sufficient to cover the vast majority of situations. Five special cases are needed to cover effective dates for individual lines which undergo transitions after the general effective date. These special cases cover the effective dates for those lines which are initially becoming subject to the standard, those lines which are changing their applicability within the standard, and those lines which are changing in a manner that removes their applicability to the standard.

Case 1 is needed because the Planning Coordinators may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2011 may identify a line to have that designation beginning in PY 2021, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. The table below has some explanatory examples of the application.

<u>Date that Planning Study is completed</u>	<u>PY the line will become an IROL element</u>	<u>Date 1</u>	<u>Date 2</u>	<u>Effective Date The latter of Date 1 or Date 2</u>
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Case 2 is needed because a line operating below 200kV designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Case 3 is needed because a line operating at 200 kV or above that once was designated as an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network. Such changes result in the need to apply R1 to that line until that date is reached and then to apply R2 to that line thereafter.

Case 4 is needed because an existing line that is to be operated at 200 kV or above can be acquired by an applicable Transmission Owner or applicable Generator Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network which will thereafter make the line subject to the standard.

Case 5 is needed because an existing line that is operated below 200 kV can be acquired by an applicable Transmission Owner or applicable Generator Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network. In this special case the line upon acquisition was designated as an element of an Interconnection Reliability Operating Limit (IROL) or an element of a Major WECC Transfer Path.

### **Defined Terms:**

#### **Explanation for revising the definition of ROW:**

The current NERC glossary definition of Right of Way has been modified to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This modified definition represents a slight but significant departure from the strict legal definition of “right of way” in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the revised definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

**Explanation for revising the definition of Vegetation Inspections:**

The current glossary definition of this NERC term is being modified to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

**Explanation of the definition of the MVCD:**

The MVCD is a calculated minimum distance that is derived from the Gallet Equations. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 below provides MVCD values for various voltages and altitudes. Details of the equations and an example calculation are provided in Appendix 1 of the Technical Reference Document.

**Requirements R1 and R2:**

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each applicable Transmission Owner or applicable Generator Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element of an IROL or Major WECC Transfer Path. R2 is applicable to all other lines that are not elements of IROLs, and not elements of Major WECC Transfer Paths.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations as described more fully in the Technical Reference document.



These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will prevent transmission outages.

If the applicable Transmission Owner or applicable Generator Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

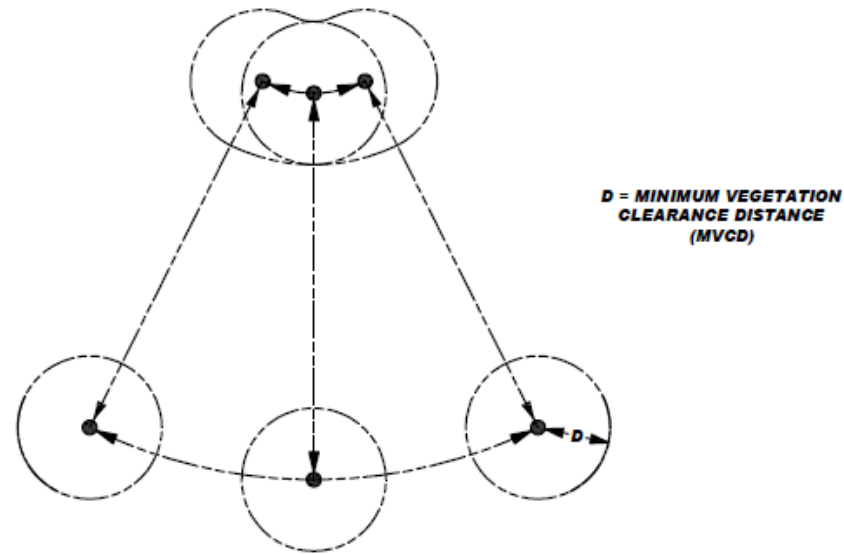
**Requirement R3:** R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable Transmission Owner or applicable Generator Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an applicable Transmission Owner or applicable Generator Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below. In the Technical Reference document more figures and explanations of conductor dynamics are provided.



**Figure 1**

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

**Requirement R4:**

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner or applicable Generator Owner employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

**Requirement R5:**

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the applicable Transmission Owner or applicable Generator Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The applicable Transmission Owner or applicable Generator Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

**Requirement R6:**

R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner’s ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission Owner or applicable Generator Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be  $100/2000 = 0.05$  or 5%. The “Low VSL” for R6 would apply in this example.

**Requirement R7:**

R7 is a risk-based requirement. The applicable Transmission Owner or applicable Generator Owner is required to complete its annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a “span-by-span”, or even a “line-by-line” detailed description of all work to be performed. It is only intended to require that the applicable Transmission Owner or applicable Generator Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

For example, when an applicable Transmission Owner or applicable Generator Owner identifies 1,000 miles of applicable transmission lines to be completed in the applicable Transmission Owner’s or applicable Generator Owner’s annual plan, the applicable Transmission Owner or applicable Generator Owner will be responsible completing those identified miles. If a applicable Transmission Owner or applicable Generator Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be:  $1000 - 100$  (deferred miles) = 900 modified annual plan, or  $900 / 900 = 100\%$  completed annual miles. If an applicable Transmission Owner or applicable Generator Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be:  $1000 - 875 = 125$  miles failed to complete then,  $125$  miles (not completed) /  $1000$  total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner’s or applicable Generator Owner’s system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.

In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner’s or applicable Generator Owner’s easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.





FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)<sup>8</sup>  
For **Alternating Current** Voltages (feet)

( AC ) Nominal System Voltage (KV)	( AC ) Maximum System Voltage (kV) <sup>9</sup>	MVCD (feet)	MVCD (feet)	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet
		Over sea level up to 500 ft	Over 500 ft up to 1000 ft	Over 1000 ft up to 2000 ft	Over 2000 ft up to 3000 ft	Over 3000 ft up to 4000 ft	Over 4000 ft up to 5000 ft	Over 5000 ft up to 6000 ft	Over 6000 ft up to 7000 ft	Over 7000 ft up to 8000 ft	Over 8000 ft up to 9000 ft	Over 9000 ft up to 10000 ft	Over 10000 ft up to 11000 ft
765	800	8.2ft	8.33ft	8.61ft	8.89ft	9.17ft	9.45ft	9.73ft	10.01ft	10.29ft	10.57ft	10.85ft	11.13ft
500	550	5.15ft	5.25ft	5.45ft	5.66ft	5.86ft	6.07ft	6.28ft	6.49ft	6.7ft	6.92ft	7.13ft	7.35ft
345	362	3.19ft	3.26ft	3.39ft	3.53ft	3.67ft	3.82ft	3.97ft	4.12ft	4.27ft	4.43ft	4.58ft	4.74ft
287	302	3.88ft	3.96ft	4.12ft	4.29ft	4.45ft	4.62ft	4.79ft	4.97ft	5.14ft	5.32ft	5.50ft	5.68ft
230	242	3.03ft	3.09ft	3.22ft	3.36ft	3.49ft	3.63ft	3.78ft	3.92ft	4.07ft	4.22ft	4.37ft	4.53ft
161*	169	2.05ft	2.09ft	2.19ft	2.28ft	2.38ft	2.48ft	2.58ft	2.69ft	2.8ft	2.91ft	3.03ft	3.14ft
138*	145	1.74ft	1.78ft	1.86ft	1.94ft	2.03ft	2.12ft	2.21ft	2.3ft	2.4ft	2.49ft	2.59ft	2.7ft
115*	121	1.44ft	1.47ft	1.54ft	1.61ft	1.68ft	1.75ft	1.83ft	1.91ft	1.99ft	2.07ft	2.16ft	2.25ft
88*	100	1.18ft	1.21ft	1.26ft	1.32ft	1.38ft	1.44ft	1.5ft	1.57ft	1.64ft	1.71ft	1.78ft	1.86ft
69*	72	0.84ft	0.86ft	0.90ft	0.94ft	0.99ft	1.03ft	1.08ft	1.13ft	1.18ft	1.23ft	1.28ft	1.34ft

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

<sup>8</sup> The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

<sup>9</sup> Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

**TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)<sup>7</sup>  
For Alternating Current Voltages (meters)**

( AC ) Nominal System Voltage (KV)	( AC ) Maximum System Voltage <sup>8</sup> (kV)	MVCD meters  Over sea level up to 152.4 m	MVCD meters  Over 152.4 m up to 304.8 m	MVCD meters  Over 304.8 m up to 609.6m	MVCD meters  Over 609.6m up to 914.4m	MVCD meters  Over 914.4m up to 1219.2m	MVCD meters  Over 1219.2m up to 1524m	MVCD meters  Over 1524 m up to 1828.8 m	MVCD meters  Over 1828.8m up to 2133.6m	MVCD meters  Over 2133.6m up to 2438.4m	MVCD meters  Over 2438.4m up to 2743.2m	MVCD meters  Over 2743.2m up to 3048m	MVCD meters  Over 3048m up to 3352.8m
765	800	2.49m	2.54m	2.62m	2.71m	2.80m	2.88m	2.97m	3.05m	3.14m	3.22m	3.31m	3.39m
500	550	1.57m	1.6m	1.66m	1.73m	1.79m	1.85m	1.91m	1.98m	2.04m	2.11m	2.17m	2.24m
345	362	0.97m	0.99m	1.03m	1.08m	1.12m	1.16m	1.21m	1.26m	1.30m	1.35m	1.40m	1.44m
287	302	1.18m	0.88m	1.26m	1.31m	1.36m	1.41m	1.46m	1.51m	1.57m	1.62m	1.68m	1.73m
230	242	0.92m	0.94m	0.98m	1.02m	1.06m	1.11m	1.15m	1.19m	1.24m	1.29m	1.33m	1.38m
161*	169	0.62m	0.64m	0.67m	0.69m	0.73m	0.76m	0.79m	0.82m	0.85m	0.89m	0.92m	0.96m
138*	145	0.53m	0.54m	0.57m	0.59m	0.62m	0.65m	0.67m	0.70m	0.73m	0.76m	0.79m	0.82m
115*	121	0.44m	0.45m	0.47m	0.49m	0.51m	0.53m	0.56m	0.58m	0.61m	0.63m	0.66m	0.69m
88*	100	0.36m	0.37m	0.38m	0.40m	0.42m	0.44m	0.46m	0.48m	0.50m	0.52m	0.54m	0.57m
69*	72	0.26m	0.26m	0.27m	0.29m	0.30m	0.31m	0.33m	0.34m	0.36m	0.37m	0.39m	0.41m

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)<sup>7</sup>  
 For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)
	Over sea level up to 500 ft	Over 500 ft up to 1000 ft	Over 1000 ft up to 2000 ft	Over 2000 ft up to 3000 ft	Over 3000 ft up to 4000 ft	Over 4000 ft up to 5000 ft	Over 5000 ft up to 6000 ft	Over 6000 ft up to 7000 ft	Over 7000 ft up to 8000 ft	Over 8000 ft up to 9000 ft	Over 9000 ft up to 10000 ft	Over 10000 ft up to 11000 ft
	(Over sea level up to 152.4 m)	(Over 152.4 m up to 304.8 m)	(Over 304.8 m up to 609.6m)	(Over 609.6m up to 914.4m)	(Over 914.4m up to 1219.2m)	(Over 1219.2m up to 1524m)	(Over 1524 m up to 1828.8 m)	(Over 1828.8m up to 2133.6m)	(Over 2133.6m up to 2438.4m)	(Over 2438.4m up to 2743.2m)	(Over 2743.2m up to 3048m)	(Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

**Notes:**

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet Equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 uses the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-01 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines, as such, are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line is approximately 2.0 per unit. This value is a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the

maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below is considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit is considered a realistic maximum.

The Gallet Equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet Equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

While EPRI is currently trying to establish empirical data for spark-over distances to live vegetation, there are no spark-over formulas currently derived expressly for vegetation to conductor minimum distances. Therefore the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice. The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

**Comparison of spark-over distances computed using Gallet wet equations vs.  
IEEE 516-2003 MAID distances**

<b>( AC ) Nom System Voltage (kV)</b>	<b>( AC ) Max System Voltage (kV)</b>	<b>Transient Over-voltage Factor (T)</b>	<b>Clearance (ft.) Gallet (wet) @ Alt. 3000 feet</b>	<b>Table 7 (Table D.5 for feet) IEEE 516-2003 MAID (ft) @ Alt. 3000 feet</b>
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

**Standard Development Timeline**

*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**

- ~~1. SC approved SAR for initial posting (January 11, 2007).~~
- ~~2. SAR posted for comment (January 15–February 14, 2007).~~
- ~~3. SAR posted for comment (April 10–May 9, 2007).~~
- ~~4. SC authorized moving the SAR forward to standard development (June 27, 2007).~~
- ~~5. First draft of proposed standard posted (October 27, 2008–November 25, 2008).~~
- ~~6. Second draft of revised standard posted (September 10, 20–October 24, 2009).~~
- ~~7. Third draft of revised standard posted (March 1, 2010–March 31, 2010).~~
- ~~8. Fourth draft of revised standard posted (June 17, 2010–July 17, 2010).~~
- ~~9. Fifth draft of revised standard posted (February 18, 2011–February 28, 2011)~~
10. Sixth draft of revised standard posted (September xx–2011)

**Proposed Action Plan and Description of Current Draft**

This is the fourth posting of the proposed revisions to the standard in accordance with Results-Based Criteria and the sixth draft overall.

**Future Development Plan**

<b>Anticipated Actions</b>	<b>Anticipated Date</b>
Recirculation ballot of standards.	September 2011
Receive BOT approval	November 2011

## Effective Dates

There are two effective dates associated with this standard.

The first effective date allows Generator Owners time to develop documented maintenance strategies or procedures or processes or specifications as outlined in Requirement R3.

In those jurisdictions where regulatory approval is required, Requirement R3 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The second effective date allows entities time to comply with Requirements R1, R2, R4, R5, R6, and R7.

In those jurisdictions where regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

~~This standard becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval is required. Where no regulatory approval is required, the standard becomes effective on the first calendar day of the first calendar quarter one year after Board of Trustees adoption.~~

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.
2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.



3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.
4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.
5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

Version History

Version	Date	Action	Change Tracking
<del>1</del>	<del>TBA</del>	<del>1. Added “Standard Development Roadmap.”</del> <del>2. Changed “60” to “Sixty” in section A, 5.2.</del> <del>3. Added “Proposed Effective Date: April 7, 2006” to footer.</del> <del>4. Added “Draft 3: November 17, 2005” to footer.</del>	<del>01/20/06</del>
<del>1</del>	<del>April 4, 2007</del>	<del>Regulatory Approval — Effective Date</del>	<del>New</del>
<del>23</del>	<del>September 29, 2011</del>	<del>Using the latest draft of FAC-003-2 from the Project 2007-07 SDT, modified proposed definitions and Applicability to include Generator Owners of a certain length.</del>	<del>Revision under Project 2010-07</del>

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

### **Right-of-Way (ROW)**

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria.

The current glossary definition of this NERC term is modified to address the issues set forth in Paragraph 734 of FERC Order 693.

### **Vegetation Inspection**

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the applicable Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.

Current definition of Vegetation Inspection:  
The systematic examination of a transmission corridor to document vegetation conditions.

### **Minimum Vegetation Clearance Distance (MVCD)**

The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

*When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.*

FAC-003-2 is currently under development under Project 2007-07. The project is nearing its final stages, but the Project 2010-07 drafting team does not want to assume that the project will be approved by NERC's Board or Trustees (BOT) or FERC. Thus, the Project 2010-07 drafting team has developed two sets of proposed changes: one to this version, the latest draft of Version 2 as proposed by the Project 2007-07 team, and one to FAC-003-1, the current FERC-approved version of the standard.

If FAC-003-2 is approved by NERC's BOT, the Project 2010-07 drafting team will likely proceed with the modifications seen in this standard. These changes would be submitted for stakeholder approval and balloted as FAC-003-3. Several scenarios that could play out based on the order of the approval of these versions of the standards are addressed in the FAC-003-3 implementation plan.

If, however, FAC-003-2 remains under development, the Project 2010-07 drafting team will proceed with changes to FAC-003-1 to avoid further delay of its project goals. Changes to FAC-003-1 would address the addition of Generator Owners to the applicability, the proposal of modifications to the NERC defined term Right-of-Way to include applicable Generator Owners, and some formatting changes to bring the standard up to date. These changes would not be comprehensive; rather, they would aim to include the generator interconnection Facility in the standard with as few other changes as possible.

## A. Introduction

1. **Title:** Transmission Vegetation Management
2. **Number:** FAC-003-~~3~~2
3. **Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

### 4. Applicability

#### 4.1. Functional Entities:

##### 4.1.1. Applicable Transmission Owners

##### 4.1.1.1. Transmission Owners that own Transmission Facilities defined in 4.2.

##### 4.1.2. Applicable Generator Owners



**Enforcement:**

The Requirements within a Reliability Standard govern and will be enforced. The Requirements within a Reliability Standard define what an entity must do to be compliant and binds an entity to certain obligations of performance under Section 215 of the Federal Power Act. Compliance will in all cases be measured by determining whether a party met or failed to meet the Reliability Standard Requirement given the specific facts and circumstances of its use, ownership or operation of the bulk power system.

Measures provide guidance on assessing non-compliance with the Requirements. Measures are the evidence that could be presented to demonstrate compliance with a Reliability Standard Requirement and are not intended to contain the quantitative metrics for determining satisfactory performance nor to limit how an entity may demonstrate compliance if valid alternatives to demonstrating compliance are available in a specific case. A Reliability Standard may be enforced in the absence of specified Measures.

Entities must comply with the “Compliance” section in its entirety, including the Administrative Procedure that sets forth, among other things, reporting requirements.

The “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” are provided for informational purposes. They are designed to convey guidance from NERC’s various activities. The “Guideline and Technical Basis” section and text boxes with “Examples” and “Rationale” are not intended to establish new Requirements under NERC’s Reliability Standards or to modify the Requirements in any existing NERC Reliability Standard. Implementation of the “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” is not a substitute for compliance with Requirements in NERC’s Reliability Standards.”

**5. Background:**

- 5.1.1.** This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:
- 5.1.2.** a) Performance-based — defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome?*
- 5.1.3.** b) Risk-based — preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?*

**5.1.4.** c) Competency-based — defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?*

**5.1.5.** The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

**5.1.6.** For this standard, the requirements have been developed as follows:

**5.1.7.** Performance-based: Requirements 1 and 2

**5.1.8.** Competency-based: Requirement 3

**5.1.9.** Risk-based: Requirements 4, 5, 6 and 7

**5.1.10.** R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). R4 serves

as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

- 5.1.11.** Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term “public lands” includes municipal lands, village lands, city lands, and a host of other governmental entities.
- 5.1.12.** This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.
- 5.1.13.** This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.
- 5.1.14.** Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.



## B. Requirements and Measures

- R1.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below<sup>3</sup> [*Violation Risk Factor: High*] [*Time Horizon: Real-time*]:
1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage<sup>4</sup>,
  2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage<sup>5</sup>,
  3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage<sup>4</sup>,
  4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage<sup>4</sup>.

- M1.** Each applicable Transmission Owner

### Rationale for R1 and R2:

Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of ~~a~~an applicable Transmission Owner's or applicable Generator Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.
2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

<sup>3</sup> This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner ~~a Transmission Owner~~ subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.

<sup>4</sup> If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

<sup>5</sup> Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

~~and applicable Generator Owner Transmission Owner~~ has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

- R2.** Each ~~applicable Transmission Owner and applicable Generator Owner Transmission Owner~~ shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below<sup>2</sup> [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time*]:
1. An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage<sup>3</sup>,
  2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage<sup>4</sup>,
  3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage<sup>4</sup>,
  4. An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage<sup>4</sup>

- M2.** Each ~~applicable Transmission Owner and applicable Generator Owner Transmission Owner~~ has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)

**R3.** Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following:

- 3.1** Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;
- 3.2** Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

*[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning];*

**Rationale**

The documentation provides a basis for evaluating the competency of the applicable Transmission Owner’s or applicable Generator Owner’s vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating

**M3.** The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

**R4.** Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment *[Violation Risk Factor: Medium] [Time Horizon: Real-time].*

**Rationale**

This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ and the control center when a critical situation is confirmed.

**M4.** Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

**R5.** When a applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ is constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

#### Rationale

Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

**M5.** Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

#### Rationale

Inspections are used by applicable Transmission Owners and applicable Generator Owners ~~Transmission Owners~~ to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors

**R6.** Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW<sup>6</sup> [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

<sup>6</sup> When the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a

**M6.** Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

**R7.** Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

**Rationale**

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

- Change in expected growth rate/ environmental factors
- Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner<sup>7</sup>
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Emerging technologies

time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.

<sup>7</sup> Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.

- M7.** Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

## C. Compliance

### 1. Compliance Monitoring Process

#### 1.1 Compliance Enforcement Authority

#### 1.2 Regional Entity Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, Measures M1, M2, M3, M5, M6 and M7 for three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.3 Compliance Monitoring and Enforcement Processes:

- 5.1.15. Compliance Audit
- 5.1.16. Self-Certification
- 5.1.17. Spot Checking
- 5.1.18. Compliance Violation Investigation
- 5.1.19. Self-Reporting
  - Complaint
  - Periodic Data Submittal



## 1.4 Additional Compliance Information

**Periodic Data Submittal:** The applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~.

A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.



The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners~~Transmission Owners~~, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Real-time	High	The <del>Transmission Owner</del> <u>responsible entity</u> failed to manage vegetation in a manner such that the <u>responsible entity</u> <del>Transmission Owner</del> had an encroachment into the MVCD observed in Real-time, absent a Sustained Outage.	The <u>responsible entity</u> <del>Transmission Owner</del> failed to manage vegetation in a manner such that the <u>responsible entity</u> <del>Transmission Owner</del> had an encroachment into the MVCD due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage.	The <u>responsible entity</u> <del>Transmission Owner</del> failed to manage vegetation in a manner such that the <u>responsible entity</u> <del>Transmission Owner</del> had an encroachment into the MVCD due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage.	The <u>responsible entity</u> <del>Transmission Owner</del> failed to manage vegetation in a manner such that the <u>responsible entity</u> <del>Transmission Owner</del> had an encroachment into the MVCD due to a grow-in that caused a vegetation-related Sustained Outage.
R2	Real-time	Medium	The <u>responsible entity</u> <del>Transmission Owner</del> failed to manage vegetation in a manner such that the <u>responsible entity</u> <del>Transmission Owner</del> had an encroachment into the MVCD observed in Real-time, absent a Sustained Outage.	The <u>responsible entity</u> <del>Transmission Owner</del> failed to manage vegetation in a manner such that the <u>responsible entity</u> <del>Transmission Owner</del> had an encroachment into the MVCD due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage.	The <u>responsible entity</u> <del>Transmission Owner</del> failed to manage vegetation in a manner such that the <u>responsible entity</u> <del>Transmission Owner</del> had an encroachment into the MVCD due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage.	The <u>responsible entity</u> <del>Transmission Owner</del> failed to manage vegetation in a manner such that the <u>responsible entity</u> <del>Transmission Owner</del> had an encroachment into the MVCD due to a grow-in that caused a vegetation-related Sustained Outage.
R3	Long-Term Planning	Lower		The <u>responsible entity</u> <del>Transmission Owner</del> has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates,	The <u>responsible entity</u> <del>Transmission Owner</del> has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating	The <u>responsible entity</u> <del>Transmission Owner</del> does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the

				vegetation control methods, and inspection frequency, for the <del>responsible entity's Transmission Owner's</del> applicable lines. (Requirement R3, Part 3.2)	and all Rated Electrical Operating Conditions, for the <del>responsible entity's Transmission Owner's</del> applicable lines. Requirement R3, Part 3.1)	<del>responsible entity's Transmission Owner's</del> applicable lines.
R4	Real-time	Medium			The <del>responsible entity Transmission Owner</del> experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The <del>responsible entity Transmission Owner</del> experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5	Operations Planning	Medium				The <del>responsible entity Transmission Owner</del> did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6	Operations Planning	Medium	The <del>responsible entity Transmission Owner</del> failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The <del>responsible entity Transmission Owner</del> failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The <del>responsible entity Transmission Owner</del> failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The <del>responsible entity Transmission Owner</del> failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7	Operations Planning	Medium	The <del>responsible entity Transmission Owner</del> failed to complete 5% or less of its annual	The <del>responsible entity Transmission Owner</del> failed to complete more than 5% and up to and including 10% of its	The <del>responsible entity Transmission Owner</del> failed to complete more than 10% and up to and including 15% of its	The <del>responsible entity Transmission Owner</del> failed to complete more than 15% of its annual vegetation work plan for

			vegetation work plan for its applicable lines (as finally modified).	annual vegetation work plan for its applicable lines (as finally modified).	annual vegetation work plan for its applicable lines (as finally modified).	its applicable lines (as finally modified).
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D. Regional Differences

None.

E. Interpretations

None.

F. Associated Documents

Guideline and Technical Basis (attached).

## Guideline and Technical Basis

### Effective dates:

The first two sentences of the Effective Dates section is standard language used in most NERC standards to cover the general effective date and is sufficient to cover the vast majority of situations. Five special cases are needed to cover effective dates for individual lines which undergo transitions after the general effective date. These special cases cover the effective dates for those lines which are initially becoming subject to the standard, those lines which are changing their applicability within the standard, and those lines which are changing in a manner that removes their applicability to the standard.

Case 1 is needed because the Planning Coordinators may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2011 may identify a line to have that designation beginning in PY 2021, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. The table below has some explanatory examples of the application.

<u>Date that Planning Study is completed</u>	<u>PY the line will become an IROL element</u>	<u>Date 1</u>	<u>Date 2</u>	<u>Effective Date The latter of Date 1 or Date 2</u>
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Case 2 is needed because a line operating below 200kV designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Case 3 is needed because a line operating at 200 kV or above that once was designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network. Such changes result in the need to apply R1 to that line until that date is reached and then to apply R2 to that line thereafter.

Case 4 is needed because an existing line that is to be operated at 200 kV or above can be acquired by an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator ~~Owner~~ ~~Transmission Owner~~, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network which will thereafter make the line subject to the standard.

Case 5 is needed because an existing line that is operated below 200 kV can be acquired by an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner ~~Transmission owner~~, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network. In this special case the line upon acquisition was designated as an element of an Interconnection Reliability Operating Limit (IROL) or an element of a Major WECC Transfer Path.

### **Defined Terms:**

#### **Explanation for revising the definition of ROW:**

The current NERC glossary definition of Right of Way has been modified to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This modified definition represents a slight but significant departure from the strict legal definition of “right of way” in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the revised definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

### **Explanation for revising the definition of Vegetation Inspections:**

The current glossary definition of this NERC term is being modified to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

### **Explanation of the definition of the MVCD:**

The MVCD is a calculated minimum distance that is derived from the Gallet Equations. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 below provides MVCD values for various voltages and altitudes. Details of the equations and an example calculation are provided in Appendix 1 of the Technical Reference Document.

### **Requirements R1 and R2:**

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element of an IROL or Major WECC Transfer Path. R2 is applicable to all other lines that are not elements of IROLs, and not elements of Major WECC Transfer Paths.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations as described more fully in the Technical Reference document.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner ~~Transmission Operator~~ or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable Transmission Owner's or applicable Generator Owner's ~~Transmission Owner's~~ inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will prevent transmission outages.

If the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ has applicable lines operated at nominal voltage levels not listed in Table 2, then the applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.



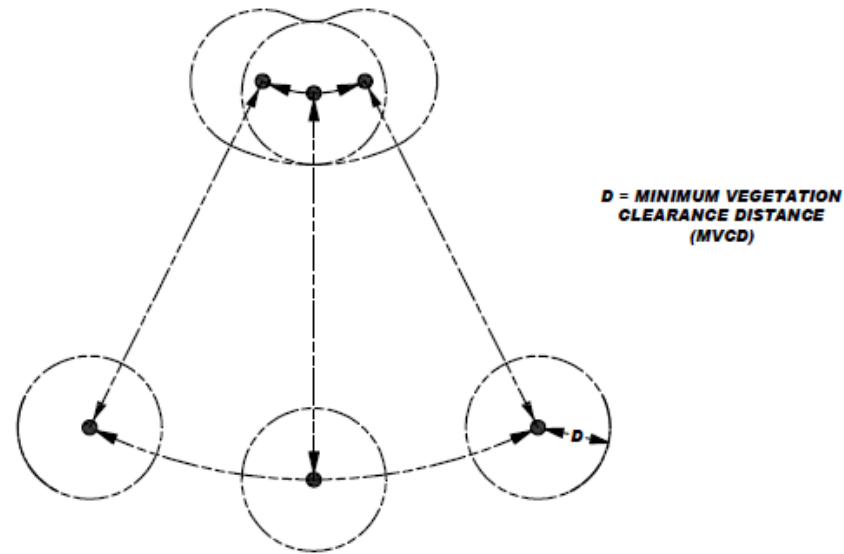
**Requirement R3:** R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below. In the Technical Reference document more figures and explanations of conductor dynamics are provided.



**Figure 1**

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

**Requirement R4:**

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner's~~ employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners ~~Transmission Owners~~ may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

#### **Requirement R5:**

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's ~~Transmission Owner's~~ rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

**Requirement R6:**

R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner's ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be  $100/2000 = 0.05$  or 5%. The "Low VSL" for R6 would apply in this example.

**Requirement R7:**

R7 is a risk-based requirement. The ~~applicable Transmission Owner or applicable Generator Owner~~ Transmission Owner is required to complete its an annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a “span-by-span”, or even a “line-by-line” detailed description of all work to be performed. It is only intended to require that the ~~applicable Transmission Owner or applicable Generator Owner~~ Transmission Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

For example, when an ~~an applicable Transmission Owner or applicable Generator Owner~~ Transmission Owner identifies 1,000 miles of applicable transmission lines to be completed in the ~~applicable Transmission Owner’s or applicable Generator Owner’s~~ Transmission Owner’s annual plan, the ~~applicable Transmission Owner or applicable Generator Owner~~ Transmission Owner will be responsible completing those identified miles. If a ~~applicable Transmission Owner or applicable Generator Owner~~ Transmission Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be:  $1000 - 100$  (deferred miles) = 900 modified annual plan, or  $900 / 900 = 100\%$  completed annual miles. If an ~~an applicable Transmission Owner or applicable Generator Owner~~ Transmission Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be:  $1000 - 875 = 125$  miles failed to complete then,  $125$  miles (not completed) /  $1000$  total annual plan miles =  $12.5\%$  failed to complete.

The ability to modify the work plan allows the ~~applicable Transmission Owner or applicable Generator Owner~~ Transmission Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the ~~applicable Transmission Owner’s or applicable Generator Owner’s~~ Transmission Owner’s system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.

In general, the vegetation management maintenance approach should use the full extent of the ~~applicable Transmission Owner’s or applicable Generator Owner’s~~ Transmission Owner’s easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners ~~Transmission Owners~~ may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.



FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)<sup>8</sup>  
For Alternating Current Voltages (feet)

( AC ) Nominal System Voltage (KV)	( AC ) Maximum System Voltage (kV) <sup>9</sup>	MVCD (feet)  Over sea level up to 500 ft	MVCD (feet)  Over 500 ft up to 1000 ft	MVCD feet  Over 1000 ft up to 2000 ft	MVCD feet  Over 2000 ft up to 3000 ft	MVCD feet  Over 3000 ft up to 4000 ft	MVCD feet  Over 4000 ft up to 5000 ft	MVCD feet  Over 5000 ft up to 6000 ft	MVCD feet  Over 6000 ft up to 7000 ft	MVCD feet  Over 7000 ft up to 8000 ft	MVCD feet  Over 8000 ft up to 9000 ft	MVCD feet  Over 9000 ft up to 10000 ft	MVCD feet  Over 10000 ft up to 11000 ft
765	800	8.2ft	8.33ft	8.61ft	8.89ft	9.17ft	9.45ft	9.73ft	10.01ft	10.29ft	10.57ft	10.85ft	11.13ft
500	550	5.15ft	5.25ft	5.45ft	5.66ft	5.86ft	6.07ft	6.28ft	6.49ft	6.7ft	6.92ft	7.13ft	7.35ft
345	362	3.19ft	3.26ft	3.39ft	3.53ft	3.67ft	3.82ft	3.97ft	4.12ft	4.27ft	4.43ft	4.58ft	4.74ft
287	302	3.88ft	3.96ft	4.12ft	4.29ft	4.45ft	4.62ft	4.79ft	4.97ft	5.14ft	5.32ft	5.50ft	5.68ft
230	242	3.03ft	3.09ft	3.22ft	3.36ft	3.49ft	3.63ft	3.78ft	3.92ft	4.07ft	4.22ft	4.37ft	4.53ft
161*	169	2.05ft	2.09ft	2.19ft	2.28ft	2.38ft	2.48ft	2.58ft	2.69ft	2.8ft	2.91ft	3.03ft	3.14ft
138*	145	1.74ft	1.78ft	1.86ft	1.94ft	2.03ft	2.12ft	2.21ft	2.3ft	2.4ft	2.49ft	2.59ft	2.7ft
115*	121	1.44ft	1.47ft	1.54ft	1.61ft	1.68ft	1.75ft	1.83ft	1.91ft	1.99ft	2.07ft	2.16ft	2.25ft
88*	100	1.18ft	1.21ft	1.26ft	1.32ft	1.38ft	1.44ft	1.5ft	1.57ft	1.64ft	1.71ft	1.78ft	1.86ft
69*	72	0.84ft	0.86ft	0.90ft	0.94ft	0.99ft	1.03ft	1.08ft	1.13ft	1.18ft	1.23ft	1.28ft	1.34ft

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

<sup>8</sup> The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

<sup>9</sup> Where applicable lines are operated at nominal voltages other than those listed, ~~the~~ the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ should use the maximum system voltage to determine the appropriate clearance for that line.



TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)<sup>7</sup>  
For Alternating Current Voltages (meters)

( AC ) Nominal System Voltage (KV)	( AC ) Maximum System Voltage <sup>8</sup> (kV)	MVCD meters  Over sea level up to 152.4 m	MVCD meters  Over 152.4 m up to 304.8 m	MVCD meters  Over 304.8 m up to 609.6m	MVCD meters  Over 609.6m up to 914.4m	MVCD meters  Over 914.4m up to 1219.2m	MVCD meters  Over 1219.2m up to 1524m	MVCD meters  Over 1524 m up to 1828.8 m	MVCD meters  Over 1828.8m up to 2133.6m	MVCD meters  Over 2133.6m up to 2438.4m	MVCD meters  Over 2438.4m up to 2743.2m	MVCD meters  Over 2743.2m up to 3048m	MVCD meters  Over 3048m up to 3352.8m
765	800	2.49m	2.54m	2.62m	2.71m	2.80m	2.88m	2.97m	3.05m	3.14m	3.22m	3.31m	3.39m
500	550	1.57m	1.6m	1.66m	1.73m	1.79m	1.85m	1.91m	1.98m	2.04m	2.11m	2.17m	2.24m
345	362	0.97m	0.99m	1.03m	1.08m	1.12m	1.16m	1.21m	1.26m	1.30m	1.35m	1.40m	1.44m
287	302	1.18m	0.88m	1.26m	1.31m	1.36m	1.41m	1.46m	1.51m	1.57m	1.62m	1.68m	1.73m
230	242	0.92m	0.94m	0.98m	1.02m	1.06m	1.11m	1.15m	1.19m	1.24m	1.29m	1.33m	1.38m
161*	169	0.62m	0.64m	0.67m	0.69m	0.73m	0.76m	0.79m	0.82m	0.85m	0.89m	0.92m	0.96m
138*	145	0.53m	0.54m	0.57m	0.59m	0.62m	0.65m	0.67m	0.70m	0.73m	0.76m	0.79m	0.82m
115*	121	0.44m	0.45m	0.47m	0.49m	0.51m	0.53m	0.56m	0.58m	0.61m	0.63m	0.66m	0.69m
88*	100	0.36m	0.37m	0.38m	0.40m	0.42m	0.44m	0.46m	0.48m	0.50m	0.52m	0.54m	0.57m
69*	72	0.26m	0.26m	0.27m	0.29m	0.30m	0.31m	0.33m	0.34m	0.36m	0.37m	0.39m	0.41m

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)<sup>7</sup>  
 For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)
	Over sea level up to 500 ft	Over 500 ft up to 1000 ft	Over 1000 ft up to 2000 ft	Over 2000 ft up to 3000 ft	Over 3000 ft up to 4000 ft	Over 4000 ft up to 5000 ft	Over 5000 ft up to 6000 ft	Over 6000 ft up to 7000 ft	Over 7000 ft up to 8000 ft	Over 8000 ft up to 9000 ft	Over 9000 ft up to 10000 ft	Over 10000 ft up to 11000 ft
	(Over sea level up to 152.4 m)	(Over 152.4 m up to 304.8 m)	(Over 304.8 m up to 609.6m)	(Over 609.6m up to 914.4m)	(Over 914.4m up to 1219.2m)	(Over 1219.2m up to 1524m)	(Over 1524 m up to 1828.8 m)	(Over 1828.8m up to 2133.6m)	(Over 2133.6m up to 2438.4m)	(Over 2438.4m up to 2743.2m)	(Over 2743.2m up to 3048m)	(Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

**Notes:**

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet Equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 uses the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-01 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines, as such, are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line is approximately 2.0 per unit. This value is a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the

maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below is considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit is considered a realistic maximum.

The Gallet Equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet Equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

While EPRI is currently trying to establish empirical data for spark-over distances to live vegetation, there are no spark-over formulas currently derived expressly for vegetation to conductor minimum distances. Therefore the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice. The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

**Comparison of spark-over distances computed using Gallet wet equations vs.  
IEEE 516-2003 MAID distances**

( AC ) Nom System Voltage (kV)	( AC ) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 feet	Table 7 (Table D.5 for feet) IEEE 516-2003 MAID (ft) @ Alt. 3000 feet
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

## Effective Dates

There are two effective dates associated with this standard.

The first effective date allows Generator Owners time to develop documented maintenance strategies or procedures or processes or specifications as outlined in Requirement R3.

In those jurisdictions where regulatory approval is required, Requirement R3 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The second effective date allows entities time to comply with Requirements R1, R2, R4, R5, R6, and R7.

In those jurisdictions where regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.
2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.
3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.

4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.
5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

Version History

<b>Version</b>	<b>Date</b>	<b>Action</b>	<b>Change Tracking</b>
3	September 29, 2011	Using the latest draft of FAC-003-2 from the Project 2007-07 SDT, modified proposed definitions and Applicability to include Generator Owners of a certain length.	Revision under Project 2010-07



## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

### **Right-of-Way (ROW)**

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria.

The current glossary definition of this NERC term is modified to address the issues set forth in Paragraph 734 of FERC Order 693.

### **Vegetation Inspection**

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the applicable Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.

Current definition of Vegetation Inspection:  
The systematic examination of a transmission corridor to document vegetation conditions.

### **Minimum Vegetation Clearance Distance (MVCD)**

The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

*When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.*

FAC-003-2 is currently under development under Project 2007-07. The project is nearing its final stages, but the Project 2010-07 drafting team does not want to assume that the project will be approved by NERC's Board or Trustees (BOT) or FERC. Thus, the Project 2010-07 drafting team has developed two sets of proposed changes: one to this version, the latest draft of Version 2 as proposed by the Project 2007-07 team, and one to FAC-003-1, the current FERC-approved version of the standard.

If FAC-003-2 is approved by NERC's BOT, the Project 2010-07 drafting team will likely proceed with the modifications seen in this standard. These changes would be submitted for stakeholder approval and balloted as FAC-003-3. Several scenarios that could play out based on the order of the approval of these versions of the standards are addressed in the FAC-003-3 implementation plan.

If, however, FAC-003-2 remains under development, the Project 2010-07 drafting team will proceed with changes to FAC-003-1 to avoid further delay of its project goals. Changes to FAC-003-1 would address the addition of Generator Owners to the applicability, the proposal of modifications to the NERC defined term Right-of-Way to include applicable Generator Owners, and some formatting changes to bring the standard up to date. These changes would not be comprehensive; rather, they would aim to include the generator interconnection Facility in the standard with as few other changes as possible.

## A. Introduction

- 1. Title:** Transmission Vegetation Management
- 2. Number:** FAC-003-3
- 3. Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.
- 4. Applicability**
  - 4.1. Functional Entities:**
    - 4.1.1. Applicable Transmission Owners**
      - 4.1.1.1. Transmission Owners that own Transmission Facilities defined in 4.2.**
    - 4.1.2. Applicable Generator Owners**

**4.1.2.1.** Generator Owners that own generation Facilities defined in 4.3

**4.2. Transmission Facilities:** Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal<sup>1</sup>, state, provincial, public, private, or tribal entities:

**4.2.1.** Each overhead transmission line operated at 200kV or higher.

**4.2.2.** Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.

**4.2.3.** Each overhead transmission line operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

**4.2.4.** Each overhead transmission line identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

**4.3. Generation Facilities:** Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal<sup>2</sup>, state, provincial, public, private, or tribal entities:

**4.3.1.** Overhead transmission lines that extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating switchyard and are:

**4.3.1.1.** Operated at 200kV or higher; or

**4.3.1.2.** Operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.

**4.3.1.3.** Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

**Rationale:** The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

Within the text of NERC Reliability Standard FAC-003-3, “transmission line(s) and “applicable line(s) can also refer to the generation Facilities as referenced in 4.3 and its subsections.

Enforcement:

<sup>1</sup> EPAAct 2005 section 1211c: “Access approvals by Federal agencies.”

<sup>2</sup> EPAAct 2005 section 1211c: “Access approvals by Federal agencies.”

The Requirements within a Reliability Standard govern and will be enforced. The Requirements within a Reliability Standard define what an entity must do to be compliant and binds an entity to certain obligations of performance under Section 215 of the Federal Power Act. Compliance will in all cases be measured by determining whether a party met or failed to meet the Reliability Standard Requirement given the specific facts and circumstances of its use, ownership or operation of the bulk power system.

Measures provide guidance on assessing non-compliance with the Requirements. Measures are the evidence that could be presented to demonstrate compliance with a Reliability Standard Requirement and are not intended to contain the quantitative metrics for determining satisfactory performance nor to limit how an entity may demonstrate compliance if valid alternatives to demonstrating compliance are available in a specific case. A Reliability Standard may be enforced in the absence of specified Measures.

Entities must comply with the “Compliance” section in its entirety, including the Administrative Procedure that sets forth, among other things, reporting requirements.

The “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” are provided for informational purposes. They are designed to convey guidance from NERC’s various activities. The “Guideline and Technical Basis” section and text boxes with “Examples” and “Rationale” are not intended to establish new Requirements under NERC’s Reliability Standards or to modify the Requirements in any existing NERC Reliability Standard. Implementation of the “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” is not a substitute for compliance with Requirements in NERC’s Reliability Standards.”

## **5. Background:**

- 5.1.1.** This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:
- 5.1.2.** a) Performance-based — defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome?*
- 5.1.3.** b) Risk-based — preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?*
- 5.1.4.** c) Competency-based — defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should

be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?*

- 5.1.5.** The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

**5.1.6.** For this standard, the requirements have been developed as follows:

**5.1.7.** Performance-based: Requirements 1 and 2

**5.1.8.** Competency-based: Requirement 3

**5.1.9.** Risk-based: Requirements 4, 5, 6 and 7

**5.1.10.** R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

- 5.1.11.** Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term “public lands” includes municipal lands, village lands, city lands, and a host of other governmental entities.
- 5.1.12.** This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.
- 5.1.13.** This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.
- 5.1.14.** Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

## B. Requirements and Measures

**R1.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below<sup>3</sup> [*Violation Risk Factor: High*] [*Time Horizon: Real-time*]:

1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage<sup>4</sup>,
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage<sup>5</sup>,
3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage<sup>4</sup>,
4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage<sup>4</sup>.

**M1.** Each applicable Transmission Owner

### Rationale for R1 and R2:

Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable Transmission Owner's or applicable Generator Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.
2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

<sup>3</sup> This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.

<sup>4</sup> If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

<sup>5</sup> Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

- R2.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below<sup>2</sup> [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time*]:
1. An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage<sup>3</sup>,
  2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage<sup>4</sup>,
  3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage<sup>4</sup>,
  4. An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage<sup>4</sup>
- M2.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)



**R3.** Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following:

**3.1** Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;

**3.2** Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

*[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]:*

**Rationale**

The documentation provides a basis for evaluating the competency of the applicable Transmission Owner’s or applicable Generator Owner’s vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions. See Figure

**M3.** The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

**R4.** Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment *[Violation Risk Factor: Medium] [Time Horizon: Real-time]*.

**Rationale**

This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

**M4.** Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

**R5.** When a applicable Transmission Owner and applicable Generator Owner is constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

**Rationale**

Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

**M5.** Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

**R6.** Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW<sup>6</sup> [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

**Rationale**

Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could

<sup>6</sup> When the applicable Transmission Owner or applicable Generator Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.

**M6.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

**R7.** Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan

**Rationale**

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

(measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

- Change in expected growth rate/ environmental factors
- Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner<sup>7</sup>
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Emerging technologies

**M7.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of

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<sup>7</sup> Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.

acceptable forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records.  
(R7)

## **C. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1 Compliance Enforcement Authority**

#### **1.2 Regional Entity Evidence Retention**

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, Measures M1, M2, M3, M5, M6 and M7 for three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### **1.3 Compliance Monitoring and Enforcement Processes:**

**5.1.15.** Compliance Audit

**5.1.16.** Self-Certification

**5.1.17.** Spot Checking

**5.1.18.** Compliance Violation Investigation

**5.1.19.** Self-Reporting

Complaint

Periodic Data Submittal

#### **1.4 Additional Compliance Information**

***Periodic Data Submittal:*** The applicable Transmission Owner and applicable Generator Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

**Table of Compliance Elements**

On November 3, NERC’s Board of Trustees adopted FAC-003-2 – Transmission Vegetation Management with NERC staff-proposed changes to the VSLs for R1 and R2 in lieu of the Project 2007-07 SDT’s original proposed VSLs. The table below now reflects the VSLs for R1 and R2 that were approved by NERC’s Board of Trustees. The only additional change made by the Project 2010-07 SDT was to change “Transmission Owner” to “responsible entity.”

R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Real-time	High			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following: <ul style="list-style-type: none"> <li>• A fall-in from inside the active transmission line ROW</li> <li>• Blowing together of applicable lines and vegetation located inside the active transmission line ROW</li> <li>• A grow-in</li> </ul>
R2	Real-time	Medium			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and	The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and

					encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.	a vegetation-related Sustained Outage was caused by one of the following: <ul style="list-style-type: none"> <li>• A fall-in from inside the active transmission line ROW</li> <li>• Blowing together of applicable lines and vegetation located inside the active transmission line ROW</li> <li>• A grow-in</li> </ul>
R3	Long-Term Planning	Lower		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity's applicable lines. (Requirement R3, Part 3.2)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines. Requirement R3, Part 3.1)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity's applicable lines.
R4	Real-time	Medium			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5	Operations Planning	Medium				The responsible entity did not take corrective action when it



						was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6	Operations Planning	Medium	The responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7	Operations Planning	Medium	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Differences

None.

E. Interpretations

None.

F. Associated Documents

Guideline and Technical Basis (attached).

## Guideline and Technical Basis

### Effective dates:

The first two sentences of the Effective Dates section is standard language used in most NERC standards to cover the general effective date and is sufficient to cover the vast majority of situations. Five special cases are needed to cover effective dates for individual lines which undergo transitions after the general effective date. These special cases cover the effective dates for those lines which are initially becoming subject to the standard, those lines which are changing their applicability within the standard, and those lines which are changing in a manner that removes their applicability to the standard.

Case 1 is needed because the Planning Coordinators may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2011 may identify a line to have that designation beginning in PY 2021, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. The table below has some explanatory examples of the application.

<u>Date that Planning Study is completed</u>	<u>PY the line will become an IROL element</u>	<u>Date 1</u>	<u>Date 2</u>	<u>Effective Date The latter of Date 1 or Date 2</u>
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Case 2 is needed because a line operating below 200kV designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Case 3 is needed because a line operating at 200 kV or above that once was designated as an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network. Such changes result in the need to apply R1 to that line until that date is reached and then to apply R2 to that line thereafter.

Case 4 is needed because an existing line that is to be operated at 200 kV or above can be acquired by an applicable Transmission Owner or applicable Generator Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network which will thereafter make the line subject to the standard.

Case 5 is needed because an existing line that is operated below 200 kV can be acquired by an applicable Transmission Owner or applicable Generator Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network. In this special case the line upon acquisition was designated as an element of an Interconnection Reliability Operating Limit (IROL) or an element of a Major WECC Transfer Path.

### **Defined Terms:**

#### **Explanation for revising the definition of ROW:**

The current NERC glossary definition of Right of Way has been modified to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This modified definition represents a slight but significant departure from the strict legal definition of “right of way” in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the revised definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

### **Explanation for revising the definition of Vegetation Inspections:**

The current glossary definition of this NERC term is being modified to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

### **Explanation of the definition of the MVCD:**

The MVCD is a calculated minimum distance that is derived from the Gallet Equations. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 below provides MVCD values for various voltages and altitudes. Details of the equations and an example calculation are provided in Appendix 1 of the Technical Reference Document.

### **Requirements R1 and R2:**

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each applicable Transmission Owner or applicable Generator Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element of an IROL or Major WECC Transfer Path. R2 is applicable to all other lines that are not elements of IROLs, and not elements of Major WECC Transfer Paths.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations as described more fully in the Technical Reference document.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will prevent transmission outages.

If the applicable Transmission Owner or applicable Generator Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

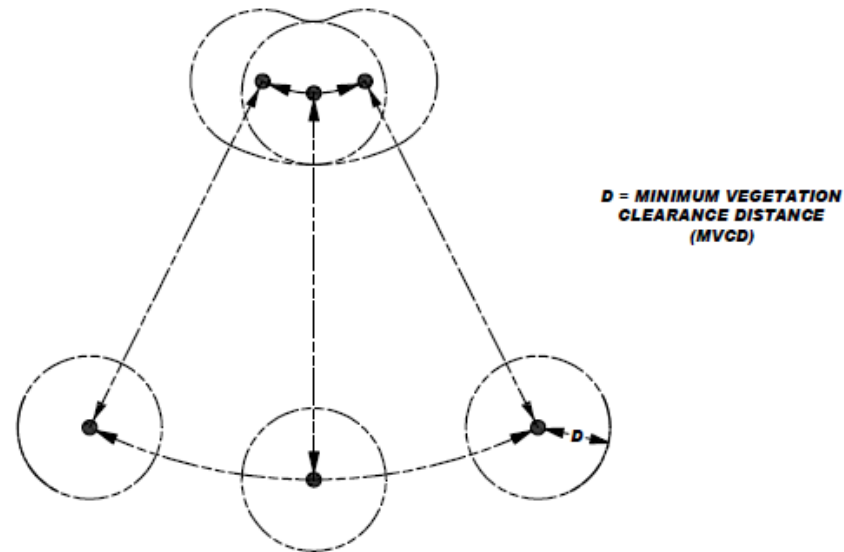
**Requirement R3:** R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable Transmission Owner or applicable Generator Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an applicable Transmission Owner or applicable Generator Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below. In the Technical Reference document more figures and explanations of conductor dynamics are provided.



**Figure 1**

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

**Requirement R4:**

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner or applicable Generator Owner employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

**Requirement R5:**

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:



- Identifying locations where the applicable Transmission Owner or applicable Generator Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The applicable Transmission Owner or applicable Generator Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

**Requirement R6:**

R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner’s ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission Owner or applicable Generator Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be  $100/2000 = 0.05$  or 5%. The “Low VSL” for R6 would apply in this example.

**Requirement R7:**

R7 is a risk-based requirement. The applicable Transmission Owner or applicable Generator Owner is required to complete its annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a “span-by-span”, or even a “line-by-line” detailed description of all work to be performed. It is only intended to require that the applicable Transmission Owner or applicable Generator Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

For example, when an applicable Transmission Owner or applicable Generator Owner identifies 1,000 miles of applicable transmission lines to be completed in the applicable Transmission Owner’s or applicable Generator Owner’s annual plan, the applicable Transmission Owner or applicable Generator Owner will be responsible completing those identified miles. If a applicable Transmission Owner or applicable Generator Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be:  $1000 - 100$  (deferred miles) = 900 modified annual plan, or  $900 / 900 = 100\%$  completed annual miles. If an applicable Transmission Owner or applicable Generator Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be:  $1000 - 875 = 125$  miles failed to complete then,  $125$  miles (not completed) /  $1000$  total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner’s or applicable Generator Owner’s system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.

In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner’s or applicable Generator Owner’s easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.



FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)<sup>8</sup>  
 For **Alternating Current** Voltages (feet)

( AC ) Nominal System Voltage (KV)	( AC ) Maximum System Voltage (kV) <sup>9</sup>	MVCD (feet)  Over sea level up to 500 ft	MVCD (feet)  Over 500 ft up to 1000 ft	MVCD feet  Over 1000 ft up to 2000 ft	MVCD feet  Over 2000 ft up to 3000 ft	MVCD feet  Over 3000 ft up to 4000 ft	MVCD feet  Over 4000 ft up to 5000 ft	MVCD feet  Over 5000 ft up to 6000 ft	MVCD feet  Over 6000 ft up to 7000 ft	MVCD feet  Over 7000 ft up to 8000 ft	MVCD feet  Over 8000 ft up to 9000 ft	MVCD feet  Over 9000 ft up to 10000 ft	MVCD feet  Over 10000 ft up to 11000 ft
765	800	8.2ft	8.33ft	8.61ft	8.89ft	9.17ft	9.45ft	9.73ft	10.01ft	10.29ft	10.57ft	10.85ft	11.13ft
500	550	5.15ft	5.25ft	5.45ft	5.66ft	5.86ft	6.07ft	6.28ft	6.49ft	6.7ft	6.92ft	7.13ft	7.35ft
345	362	3.19ft	3.26ft	3.39ft	3.53ft	3.67ft	3.82ft	3.97ft	4.12ft	4.27ft	4.43ft	4.58ft	4.74ft
287	302	3.88ft	3.96ft	4.12ft	4.29ft	4.45ft	4.62ft	4.79ft	4.97ft	5.14ft	5.32ft	5.50ft	5.68ft
230	242	3.03ft	3.09ft	3.22ft	3.36ft	3.49ft	3.63ft	3.78ft	3.92ft	4.07ft	4.22ft	4.37ft	4.53ft
161*	169	2.05ft	2.09ft	2.19ft	2.28ft	2.38ft	2.48ft	2.58ft	2.69ft	2.8ft	2.91ft	3.03ft	3.14ft
138*	145	1.74ft	1.78ft	1.86ft	1.94ft	2.03ft	2.12ft	2.21ft	2.3ft	2.4ft	2.49ft	2.59ft	2.7ft
115*	121	1.44ft	1.47ft	1.54ft	1.61ft	1.68ft	1.75ft	1.83ft	1.91ft	1.99ft	2.07ft	2.16ft	2.25ft
88*	100	1.18ft	1.21ft	1.26ft	1.32ft	1.38ft	1.44ft	1.5ft	1.57ft	1.64ft	1.71ft	1.78ft	1.86ft
69*	72	0.84ft	0.86ft	0.90ft	0.94ft	0.99ft	1.03ft	1.08ft	1.13ft	1.18ft	1.23ft	1.28ft	1.34ft

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

<sup>8</sup> The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

<sup>9</sup> Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

**TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)<sup>7</sup>  
For Alternating Current Voltages (meters)**

( AC ) Nominal System Voltage (KV)	( AC ) Maximum System Voltage <sup>8</sup> (kV)	MVCD meters  Over sea level up to 152.4 m	MVCD meters  Over 152.4 m up to 304.8 m	MVCD meters  Over 304.8 m up to 609.6m	MVCD meters  Over 609.6m up to 914.4m	MVCD meters  Over 914.4m up to 1219.2m	MVCD meters  Over 1219.2m up to 1524m	MVCD meters  Over 1524 m up to 1828.8 m	MVCD meters  Over 1828.8m up to 2133.6m	MVCD meters  Over 2133.6m up to 2438.4m	MVCD meters  Over 2438.4m up to 2743.2m	MVCD meters  Over 2743.2m up to 3048m	MVCD meters  Over 3048m up to 3352.8m
765	800	2.49m	2.54m	2.62m	2.71m	2.80m	2.88m	2.97m	3.05m	3.14m	3.22m	3.31m	3.39m
500	550	1.57m	1.6m	1.66m	1.73m	1.79m	1.85m	1.91m	1.98m	2.04m	2.11m	2.17m	2.24m
345	362	0.97m	0.99m	1.03m	1.08m	1.12m	1.16m	1.21m	1.26m	1.30m	1.35m	1.40m	1.44m
287	302	1.18m	0.88m	1.26m	1.31m	1.36m	1.41m	1.46m	1.51m	1.57m	1.62m	1.68m	1.73m
230	242	0.92m	0.94m	0.98m	1.02m	1.06m	1.11m	1.15m	1.19m	1.24m	1.29m	1.33m	1.38m
161*	169	0.62m	0.64m	0.67m	0.69m	0.73m	0.76m	0.79m	0.82m	0.85m	0.89m	0.92m	0.96m
138*	145	0.53m	0.54m	0.57m	0.59m	0.62m	0.65m	0.67m	0.70m	0.73m	0.76m	0.79m	0.82m
115*	121	0.44m	0.45m	0.47m	0.49m	0.51m	0.53m	0.56m	0.58m	0.61m	0.63m	0.66m	0.69m
88*	100	0.36m	0.37m	0.38m	0.40m	0.42m	0.44m	0.46m	0.48m	0.50m	0.52m	0.54m	0.57m
69*	72	0.26m	0.26m	0.27m	0.29m	0.30m	0.31m	0.33m	0.34m	0.36m	0.37m	0.39m	0.41m

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)<sup>7</sup>  
 For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)
	Over sea level up to 500 ft	Over 500 ft up to 1000 ft	Over 1000 ft up to 2000 ft	Over 2000 ft up to 3000 ft	Over 3000 ft up to 4000 ft	Over 4000 ft up to 5000 ft	Over 5000 ft up to 6000 ft	Over 6000 ft up to 7000 ft	Over 7000 ft up to 8000 ft	Over 8000 ft up to 9000 ft	Over 9000 ft up to 10000 ft	Over 10000 ft up to 11000 ft
	(Over sea level up to 152.4 m)	(Over 152.4 m up to 304.8 m)	(Over 304.8 m up to 609.6m)	(Over 609.6m up to 914.4m)	(Over 914.4m up to 1219.2m)	(Over 1219.2m up to 1524m)	(Over 1524 m up to 1828.8 m)	(Over 1828.8m up to 2133.6m)	(Over 2133.6m up to 2438.4m)	(Over 2438.4m up to 2743.2m)	(Over 2743.2m up to 3048m)	(Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

**Notes:**

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet Equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 uses the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-01 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines, as such, are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line is approximately 2.0 per unit. This value is a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the



maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below is considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit is considered a realistic maximum.

The Gallet Equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet Equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

While EPRI is currently trying to establish empirical data for spark-over distances to live vegetation, there are no spark-over formulas currently derived expressly for vegetation to conductor minimum distances. Therefore the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice. The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

**Comparison of spark-over distances computed using Gallet wet equations vs.  
IEEE 516-2003 MAID distances**

( AC ) Nom System Voltage (kV)	( AC ) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 feet	Table 7 (Table D.5 for feet) IEEE 516-2003 MAID (ft) @ Alt. 3000 feet
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

**Standard Development Timeline**

*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**

- ~~1. SC approved SAR for initial posting (January 11, 2007).~~
- ~~2. SAR posted for comment (January 15–February 14, 2007).~~
- ~~3. SAR posted for comment (April 10–May 9, 2007).~~
- ~~4. SC authorized moving the SAR forward to standard development (June 27, 2007).~~
- ~~5. First draft of proposed standard posted (October 27, 2008–November 25, 2008).~~
- ~~6. Second draft of revised standard posted (September 10, 20–October 24, 2009).~~
- ~~7. Third draft of revised standard posted (March 1, 2010–March 31, 2010).~~
- ~~8. Fourth draft of revised standard posted (June 17, 2010–July 17, 2010).~~
- ~~9. Fifth draft of revised standard posted (February 18, 2011–February 28, 2011)~~
10. Sixth draft of revised standard posted (September xx–2011)

**Proposed Action Plan and Description of Current Draft**

This is the fourth posting of the proposed revisions to the standard in accordance with Results-Based Criteria and the sixth draft overall.

**Future Development Plan**

<b>Anticipated Actions</b>	<b>Anticipated Date</b>
Recirculation ballot of standards.	September 2011
Receive BOT approval	November 2011

## Effective Dates

There are two effective dates associated with this standard.

The first effective date allows Generator Owners time to develop documented maintenance strategies or procedures or processes or specifications as outlined in Requirement R3.

In those jurisdictions where regulatory approval is required, Requirement R3 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The second effective date allows entities time to comply with Requirements R1, R2, R4, R5, R6, and R7.

In those jurisdictions where regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

~~This standard becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval is required. Where no regulatory approval is required, the standard becomes effective on the first calendar day of the first calendar quarter one year after Board of Trustees adoption.~~

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.
2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.

3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.
4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.
5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

Version History

Version	Date	Action	Change Tracking
<del>1</del>	<del>TBA</del>	<del>1. Added “Standard Development Roadmap.”</del> <del>2. Changed “60” to “Sixty” in section A, 5.2.</del> <del>3. Added “Proposed Effective Date: April 7, 2006” to footer.</del> <del>4. Added “Draft 3: November 17, 2005” to footer.</del>	<del>01/20/06</del>
<del>1</del>	<del>April 4, 2007</del>	<del>Regulatory Approval — Effective Date</del>	<del>New</del>
<del>23</del>	<del>September 29, 2011</del>	<del>Using the latest draft of FAC-003-2 from the Project 2007-07 SDT, modified proposed definitions and Applicability to include Generator Owners of a certain length.</del>	<del>Revision under Project 2010-07</del>

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

### **Right-of-Way (ROW)**

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria.

The current glossary definition of this NERC term is modified to address the issues set forth in Paragraph 734 of FERC Order 693.

### **Vegetation Inspection**

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the applicable Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.

Current definition of Vegetation Inspection:  
The systematic examination of a transmission corridor to document vegetation conditions.

### **Minimum Vegetation Clearance Distance (MVCD)**

The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

*When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.*

FAC-003-2 is currently under development under Project 2007-07. The project is nearing its final stages, but the Project 2010-07 drafting team does not want to assume that the project will be approved by NERC's Board or Trustees (BOT) or FERC. Thus, the Project 2010-07 drafting team has developed two sets of proposed changes: one to this version, the latest draft of Version 2 as proposed by the Project 2007-07 team, and one to FAC-003-1, the current FERC-approved version of the standard.

If FAC-003-2 is approved by NERC's BOT, the Project 2010-07 drafting team will likely proceed with the modifications seen in this standard. These changes would be submitted for stakeholder approval and balloted as FAC-003-3. Several scenarios that could play out based on the order of the approval of these versions of the standards are addressed in the FAC-003-3 implementation plan.

If, however, FAC-003-2 remains under development, the Project 2010-07 drafting team will proceed with changes to FAC-003-1 to avoid further delay of its project goals. Changes to FAC-003-1 would address the addition of Generator Owners to the applicability, the proposal of modifications to the NERC defined term Right-of-Way to include applicable Generator Owners, and some formatting changes to bring the standard up to date. These changes would not be comprehensive; rather, they would aim to include the generator interconnection Facility in the standard with as few other changes as possible.

## A. Introduction

1. **Title:** Transmission Vegetation Management
2. **Number:** FAC-003-~~3~~2
3. **Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

### 4. Applicability

#### 4.1. Functional Entities:

##### 4.1.1. Applicable Transmission Owners

##### 4.1.1.1. Transmission Owners that own Transmission Facilities defined in 4.2.

##### 4.1.2. Applicable Generator Owners





**Enforcement:**

The Requirements within a Reliability Standard govern and will be enforced. The Requirements within a Reliability Standard define what an entity must do to be compliant and binds an entity to certain obligations of performance under Section 215 of the Federal Power Act. Compliance will in all cases be measured by determining whether a party met or failed to meet the Reliability Standard Requirement given the specific facts and circumstances of its use, ownership or operation of the bulk power system.

Measures provide guidance on assessing non-compliance with the Requirements. Measures are the evidence that could be presented to demonstrate compliance with a Reliability Standard Requirement and are not intended to contain the quantitative metrics for determining satisfactory performance nor to limit how an entity may demonstrate compliance if valid alternatives to demonstrating compliance are available in a specific case. A Reliability Standard may be enforced in the absence of specified Measures.

Entities must comply with the “Compliance” section in its entirety, including the Administrative Procedure that sets forth, among other things, reporting requirements.

The “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” are provided for informational purposes. They are designed to convey guidance from NERC’s various activities. The “Guideline and Technical Basis” section and text boxes with “Examples” and “Rationale” are not intended to establish new Requirements under NERC’s Reliability Standards or to modify the Requirements in any existing NERC Reliability Standard. Implementation of the “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” is not a substitute for compliance with Requirements in NERC’s Reliability Standards.”

**5. Background:**

- 5.1.1.** This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:
- 5.1.2.** a) Performance-based — defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome?*
- 5.1.3.** b) Risk-based — preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?*

**5.1.4.** c) Competency-based — defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?*

**5.1.5.** The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

**5.1.6.** For this standard, the requirements have been developed as follows:

**\*5.1.7.** Performance-based: Requirements 1 and 2

**\*5.1.8.** Competency-based: Requirement 3

**\*5.1.9.** Risk-based: Requirements 4, 5, 6 and 7

**5.1.10.** R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). R4 serves

as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

- 5.1.11.** Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term “public lands” includes municipal lands, village lands, city lands, and a host of other governmental entities.
- 5.1.12.** This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.
- 5.1.13.** This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.
- 5.1.14.** Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

## B. Requirements and Measures

**R1.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below<sup>3</sup> [*Violation Risk Factor: High*] [*Time Horizon: Real-time*]:

1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage<sup>4</sup>,
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage<sup>5</sup>,
3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage<sup>4</sup>,
4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage<sup>4</sup>.

**M1.** Each applicable Transmission Owner

### Rationale for R1 and R2:

Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of ~~a~~an applicable Transmission Owner's or applicable Generator Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.
2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

<sup>3</sup> This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner ~~a Transmission Owner~~ subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.

<sup>4</sup> If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

<sup>5</sup> Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

~~and applicable Generator Owner Transmission Owner~~ has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

**R2.** Each ~~applicable Transmission Owner and applicable Generator Owner Transmission Owner~~ shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below<sup>2</sup> [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time*]:

1. An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage<sup>3</sup>,
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage<sup>4</sup>,
3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage<sup>4</sup>,
4. An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage<sup>4</sup>

**M2.** Each ~~applicable Transmission Owner and applicable Generator Owner Transmission Owner~~ has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)



**R3.** Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following:

- 3.1** Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;
- 3.2** Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

*[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning];*

**Rationale**

The documentation provides a basis for evaluating the competency of the applicable Transmission Owner’s or applicable Generator Owner’s vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating

**M3.** The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

**R4.** Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment *[Violation Risk Factor: Medium] [Time Horizon: Real-time].*

**Rationale**

This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ and the control center when a critical situation is confirmed.

**M4.** Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

**R5.** When a applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ is constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

**Rationale**

Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

**M5.** Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

**Rationale**

Inspections are used by applicable Transmission Owners and applicable Generator Owners ~~Transmission Owners~~ to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors

**R6.** Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW<sup>6</sup> [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

<sup>6</sup> When the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a



**M6.** Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

**R7.** Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

**Rationale**

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

- Change in expected growth rate/ environmental factors
- Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner<sup>7</sup>
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Emerging technologies

time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.

<sup>7</sup> Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.

- M7.** Each applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

## C. Compliance

### 1. Compliance Monitoring Process

#### 1.1 Compliance Enforcement Authority

#### 1.2 Regional Entity Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, Measures M1, M2, M3, M5, M6 and M7 for three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.3 Compliance Monitoring and Enforcement Processes:

- 5.1.15. Compliance Audit
- 5.1.16. Self-Certification
- 5.1.17. Spot Checking
- 5.1.18. Compliance Violation Investigation
- 5.1.19. Self-Reporting
  - Complaint
  - Periodic Data Submittal

## 1.4 Additional Compliance Information

**Periodic Data Submittal:** The applicable Transmission Owner and applicable Generator Owner ~~Transmission Owner~~ will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~.

A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners~~Transmission Owners~~, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

**Table of Compliance Elements**

On November 3, NERC’s Board of Trustees adopted FAC-003-2 – Transmission Vegetation Management with NERC staff-proposed changes to the VSLs for R1 and R2 in lieu of the Project 2007-07 SDT’s original proposed VSLs. Those latest changes are reflected here. The only additional change made by the Project 2010-07 SDT was to change “Transmission Owner” to “responsible entity” in both sets of VSLs.

R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Real-time	High	<p><del>The Transmission Owner responsible entity failed to manage vegetation in a manner such that the responsible entity Transmission Owner had an encroachment into the MVCD observed in Real-time, absent a Sustained Outage.</del></p>	<p><del>The responsible entity Transmission Owner failed to manage vegetation in a manner such that the responsible entity Transmission Owner had an encroachment into the MVCD due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage.</del></p>	<p><del>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage. The responsible entity Transmission Owner failed to manage vegetation in a manner such that the responsible entity Transmission Owner had an encroachment into the MVCD due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage.</del></p>	<p><del>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following:</del></p> <ul style="list-style-type: none"> <li><del>• A fall-in from inside the active transmission line ROW</del></li> <li><del>• Blowing together of applicable lines and vegetation located inside the active transmission line ROW</del></li> <li><del>• A grow-in The responsible entity Transmission Owner failed to manage vegetation in a manner such that the responsible entity Transmission Owner had an encroachment into the MVCD due to a grow-in</del></li> </ul>

						that caused a vegetation-related Sustained Outage.
R2	Real-time	Medium	<del>The responsible entity Transmission Owner failed to manage vegetation in a manner such that the responsible entity Transmission Owner had an encroachment into the MVCD observed in Real-time, absent a Sustained Outage.</del>	<del>The responsible entity Transmission Owner failed to manage vegetation in a manner such that the responsible entity Transmission Owner had an encroachment into the MVCD due to a fall in from inside the ROW that caused a vegetation-related Sustained Outage.</del>	<del>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage. The responsible entity Transmission Owner failed to manage vegetation in a manner such that the responsible entity Transmission Owner had an encroachment into the MVCD due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage.</del>	<del>The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following:</del> <ul style="list-style-type: none"> <li><del>• A fall-in from inside the active transmission line ROW</del></li> <li><del>• Blowing together of applicable lines and vegetation located inside the active transmission line ROW</del></li> <li><del>• A grow-in The responsible entity Transmission Owner failed to manage vegetation in a manner such that the responsible entity Transmission Owner had an encroachment into the MVCD due to a grow in that caused a vegetation-related Sustained Outage.</del></li> </ul>
R3	Long-Term Planning	Lower		<del>The responsible entity Transmission Owner has maintenance strategies or documented procedures or processes or specifications but has not accounted for the</del>	<del>The responsible entity Transmission Owner has maintenance strategies or documented procedures or processes or specifications but has not accounted for the</del>	<del>The responsible entity Transmission Owner does not have any maintenance strategies or documented procedures or processes or specifications used to prevent</del>

				inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the <del>responsible entity's Transmission Owner's</del> applicable lines. (Requirement R3, Part 3.2)	movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the <del>responsible entity's Transmission Owner's</del> applicable lines. Requirement R3, Part 3.1)	the encroachment of vegetation into the MVCD, for the <del>responsible entity's Transmission Owner's</del> applicable lines.
R4	Real-time	Medium			The <del>responsible entity Transmission Owner</del> experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The <del>responsible entity Transmission Owner</del> experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5	Operations Planning	Medium				The <del>responsible entity Transmission Owner</del> did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6	Operations Planning	Medium	The <del>responsible entity Transmission Owner</del> failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The <del>responsible entity Transmission Owner</del> failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The <del>responsible entity Transmission Owner</del> failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The <del>responsible entity Transmission Owner</del> failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7	Operations Planning	Medium	The <del>responsible entity Transmission Owner</del>	The <del>responsible entity Transmission Owner</del> failed to	The <del>responsible entity Transmission Owner</del> failed to	The <del>responsible entity Transmission Owner</del> failed to



			failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).
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D. Regional Differences

None.

E. Interpretations

None.

F. Associated Documents

Guideline and Technical Basis (attached).

## Guideline and Technical Basis

### Effective dates:

The first two sentences of the Effective Dates section is standard language used in most NERC standards to cover the general effective date and is sufficient to cover the vast majority of situations. Five special cases are needed to cover effective dates for individual lines which undergo transitions after the general effective date. These special cases cover the effective dates for those lines which are initially becoming subject to the standard, those lines which are changing their applicability within the standard, and those lines which are changing in a manner that removes their applicability to the standard.

Case 1 is needed because the Planning Coordinators may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2011 may identify a line to have that designation beginning in PY 2021, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. The table below has some explanatory examples of the application.

<u>Date that Planning Study is completed</u>	<u>PY the line will become an IROL element</u>	<u>Date 1</u>	<u>Date 2</u>	<u>Effective Date The latter of Date 1 or Date 2</u>
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Case 2 is needed because a line operating below 200kV designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Case 3 is needed because a line operating at 200 kV or above that once was designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network. Such changes result in the need to apply R1 to that line until that date is reached and then to apply R2 to that line thereafter.

Case 4 is needed because an existing line that is to be operated at 200 kV or above can be acquired by an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator ~~Owner~~ ~~Transmission Owner~~, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network which will thereafter make the line subject to the standard.

Case 5 is needed because an existing line that is operated below 200 kV can be acquired by an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner ~~Transmission owner~~, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network. In this special case the line upon acquisition was designated as an element of an Interconnection Reliability Operating Limit (IROL) or an element of a Major WECC Transfer Path.

### **Defined Terms:**

#### **Explanation for revising the definition of ROW:**

The current NERC glossary definition of Right of Way has been modified to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This modified definition represents a slight but significant departure from the strict legal definition of “right of way” in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the revised definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

### **Explanation for revising the definition of Vegetation Inspections:**

The current glossary definition of this NERC term is being modified to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

### **Explanation of the definition of the MVCD:**

The MVCD is a calculated minimum distance that is derived from the Gallet Equations. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 below provides MVCD values for various voltages and altitudes. Details of the equations and an example calculation are provided in Appendix 1 of the Technical Reference Document.

### **Requirements R1 and R2:**

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element of an IROL or Major WECC Transfer Path. R2 is applicable to all other lines that are not elements of IROLs, and not elements of Major WECC Transfer Paths.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations as described more fully in the Technical Reference document.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner ~~Transmission Operator~~ or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable Transmission Owner's or applicable Generator Owner's ~~Transmission Owner's~~ inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will prevent transmission outages.

If the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ has applicable lines operated at nominal voltage levels not listed in Table 2, then the applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

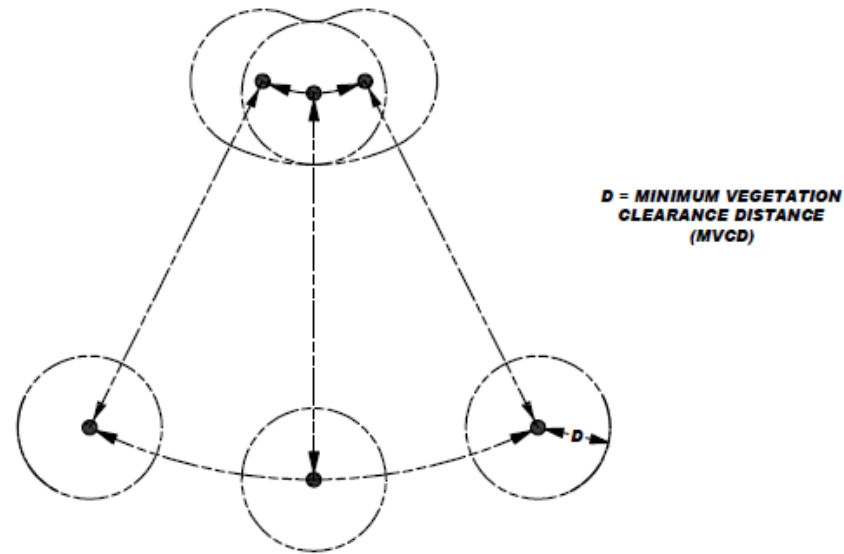
**Requirement R3:** R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below. In the Technical Reference document more figures and explanations of conductor dynamics are provided.



**Figure 1**

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

**Requirement R4:**

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner's~~ employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners ~~Transmission Owners~~ may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

**Requirement R5:**

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's ~~Transmission Owner's~~ rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:



- Identifying locations where the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

**Requirement R6:**

R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner’s ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when an applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be  $100/2000 = 0.05$  or 5%. The “Low VSL” for R6 would apply in this example.

**Requirement R7:**

R7 is a risk-based requirement. The ~~applicable Transmission Owner or applicable Generator Owner~~ Transmission Owner is required to complete its an annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a “span-by-span”, or even a “line-by-line” detailed description of all work to be performed. It is only intended to require that the ~~applicable Transmission Owner or applicable Generator Owner~~ Transmission Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

For example, when an ~~an applicable Transmission Owner or applicable Generator Owner~~ Transmission Owner identifies 1,000 miles of applicable transmission lines to be completed in the ~~applicable Transmission Owner’s or applicable Generator Owner’s~~ Transmission Owner’s annual plan, the ~~applicable Transmission Owner or applicable Generator Owner~~ Transmission Owner will be responsible completing those identified miles. If a ~~applicable Transmission Owner or applicable Generator Owner~~ Transmission Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be:  $1000 - 100$  (deferred miles) = 900 modified annual plan, or  $900 / 900 = 100\%$  completed annual miles. If an ~~an applicable Transmission Owner or applicable Generator Owner~~ Transmission Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be:  $1000 - 875 = 125$  miles failed to complete then,  $125$  miles (not completed) / 1000 total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the ~~applicable Transmission Owner or applicable Generator Owner~~ Transmission Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the ~~applicable Transmission Owner’s or applicable Generator Owner’s~~ Transmission Owner’s system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.

In general, the vegetation management maintenance approach should use the full extent of the ~~applicable Transmission Owner’s or applicable Generator Owner’s~~ Transmission Owner’s easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners ~~Transmission Owners~~ may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.



FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)<sup>8</sup>  
For Alternating Current Voltages (feet)

( AC ) Nominal System Voltage (KV)	( AC ) Maximum System Voltage (kV) <sup>9</sup>	MVCD (feet)	MVCD (feet)	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet
		Over sea level up to 500 ft	Over 500 ft up to 1000 ft	Over 1000 ft up to 2000 ft	Over 2000 ft up to 3000 ft	Over 3000 ft up to 4000 ft	Over 4000 ft up to 5000 ft	Over 5000 ft up to 6000 ft	Over 6000 ft up to 7000 ft	Over 7000 ft up to 8000 ft	Over 8000 ft up to 9000 ft	Over 9000 ft up to 10000 ft	Over 10000 ft up to 11000 ft
765	800	8.2ft	8.33ft	8.61ft	8.89ft	9.17ft	9.45ft	9.73ft	10.01ft	10.29ft	10.57ft	10.85ft	11.13ft
500	550	5.15ft	5.25ft	5.45ft	5.66ft	5.86ft	6.07ft	6.28ft	6.49ft	6.7ft	6.92ft	7.13ft	7.35ft
345	362	3.19ft	3.26ft	3.39ft	3.53ft	3.67ft	3.82ft	3.97ft	4.12ft	4.27ft	4.43ft	4.58ft	4.74ft
287	302	3.88ft	3.96ft	4.12ft	4.29ft	4.45ft	4.62ft	4.79ft	4.97ft	5.14ft	5.32ft	5.50ft	5.68ft
230	242	3.03ft	3.09ft	3.22ft	3.36ft	3.49ft	3.63ft	3.78ft	3.92ft	4.07ft	4.22ft	4.37ft	4.53ft
161*	169	2.05ft	2.09ft	2.19ft	2.28ft	2.38ft	2.48ft	2.58ft	2.69ft	2.8ft	2.91ft	3.03ft	3.14ft
138*	145	1.74ft	1.78ft	1.86ft	1.94ft	2.03ft	2.12ft	2.21ft	2.3ft	2.4ft	2.49ft	2.59ft	2.7ft
115*	121	1.44ft	1.47ft	1.54ft	1.61ft	1.68ft	1.75ft	1.83ft	1.91ft	1.99ft	2.07ft	2.16ft	2.25ft
88*	100	1.18ft	1.21ft	1.26ft	1.32ft	1.38ft	1.44ft	1.5ft	1.57ft	1.64ft	1.71ft	1.78ft	1.86ft
69*	72	0.84ft	0.86ft	0.90ft	0.94ft	0.99ft	1.03ft	1.08ft	1.13ft	1.18ft	1.23ft	1.28ft	1.34ft

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

<sup>8</sup> The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

<sup>9</sup> Where applicable lines are operated at nominal voltages other than those listed, ~~the~~ the applicable Transmission Owner or applicable Generator Owner ~~Transmission Owner~~ should use the maximum system voltage to determine the appropriate clearance for that line.

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)<sup>7</sup>  
For Alternating Current Voltages (meters)

( AC ) Nominal System Voltage (KV)	( AC ) Maximum System Voltage <sup>8</sup> (kV)	MVCD meters  Over sea level up to 152.4 m	MVCD meters  Over 152.4 m up to 304.8 m	MVCD meters  Over 304.8 m up to 609.6m	MVCD meters  Over 609.6m up to 914.4m	MVCD meters  Over 914.4m up to 1219.2m	MVCD meters  Over 1219.2m up to 1524m	MVCD meters  Over 1524 m up to 1828.8 m	MVCD meters  Over 1828.8m up to 2133.6m	MVCD meters  Over 2133.6m up to 2438.4m	MVCD meters  Over 2438.4m up to 2743.2m	MVCD meters  Over 2743.2m up to 3048m	MVCD meters  Over 3048m up to 3352.8m
765	800	2.49m	2.54m	2.62m	2.71m	2.80m	2.88m	2.97m	3.05m	3.14m	3.22m	3.31m	3.39m
500	550	1.57m	1.6m	1.66m	1.73m	1.79m	1.85m	1.91m	1.98m	2.04m	2.11m	2.17m	2.24m
345	362	0.97m	0.99m	1.03m	1.08m	1.12m	1.16m	1.21m	1.26m	1.30m	1.35m	1.40m	1.44m
287	302	1.18m	0.88m	1.26m	1.31m	1.36m	1.41m	1.46m	1.51m	1.57m	1.62m	1.68m	1.73m
230	242	0.92m	0.94m	0.98m	1.02m	1.06m	1.11m	1.15m	1.19m	1.24m	1.29m	1.33m	1.38m
161*	169	0.62m	0.64m	0.67m	0.69m	0.73m	0.76m	0.79m	0.82m	0.85m	0.89m	0.92m	0.96m
138*	145	0.53m	0.54m	0.57m	0.59m	0.62m	0.65m	0.67m	0.70m	0.73m	0.76m	0.79m	0.82m
115*	121	0.44m	0.45m	0.47m	0.49m	0.51m	0.53m	0.56m	0.58m	0.61m	0.63m	0.66m	0.69m
88*	100	0.36m	0.37m	0.38m	0.40m	0.42m	0.44m	0.46m	0.48m	0.50m	0.52m	0.54m	0.57m
69*	72	0.26m	0.26m	0.27m	0.29m	0.30m	0.31m	0.33m	0.34m	0.36m	0.37m	0.39m	0.41m

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)<sup>7</sup>  
 For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)
	Over sea level up to 500 ft	Over 500 ft up to 1000 ft	Over 1000 ft up to 2000 ft	Over 2000 ft up to 3000 ft	Over 3000 ft up to 4000 ft	Over 4000 ft up to 5000 ft	Over 5000 ft up to 6000 ft	Over 6000 ft up to 7000 ft	Over 7000 ft up to 8000 ft	Over 8000 ft up to 9000 ft	Over 9000 ft up to 10000 ft	Over 10000 ft up to 11000 ft
	(Over sea level up to 152.4 m)	(Over 152.4 m up to 304.8 m)	(Over 304.8 m up to 609.6m)	(Over 609.6m up to 914.4m)	(Over 914.4m up to 1219.2m)	(Over 1219.2m up to 1524m)	(Over 1524 m up to 1828.8 m)	(Over 1828.8m up to 2133.6m)	(Over 2133.6m up to 2438.4m)	(Over 2438.4m up to 2743.2m)	(Over 2743.2m up to 3048m)	(Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

**Notes:**

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet Equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 uses the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-01 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines, as such, are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line is approximately 2.0 per unit. This value is a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the



maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below is considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit is considered a realistic maximum.

The Gallet Equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet Equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

While EPRI is currently trying to establish empirical data for spark-over distances to live vegetation, there are no spark-over formulas currently derived expressly for vegetation to conductor minimum distances. Therefore the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice. The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

**Comparison of spark-over distances computed using Gallet wet equations vs.  
IEEE 516-2003 MAID distances**

( AC ) Nom System Voltage (kV)	( AC ) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 feet	Table 7 (Table D.5 for feet) IEEE 516-2003 MAID (ft) @ Alt. 3000 feet
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

## Standard PRC-004-2.1 – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

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### A. Introduction

1. **Title:** Analysis and Mitigation of Transmission and Generation Protection System Misoperations
2. **Number:** PRC-004-2.1
3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.
4. **Applicability**
  - 4.1. Transmission Owner.
  - 4.2. Distribution Provider that owns a transmission Protection System.
  - 4.3. Generator Owner.
5. **(Proposed) Effective Date:** In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements become effective upon Board of Trustees' adoption.

### B. Requirements

- R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- R2. The Generator Owner shall analyze its generator and generator interconnection Facility Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.

### C. Measures

- M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Entity's procedures.

### D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Enforcement Authority**  
Regional Entity.

## Standard PRC-004-2.1 – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

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### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

### 1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

### 1.4. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

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

### 1.5. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

## 2. Violation Severity Levels (no changes)

### E. Regional Differences

None identified.

### Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
2	TBD	Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised.
3	XX	Errata change: Edited R2 to add “...and generator interconnection Facility...”	Revision under Project 2010-07

## Standard PRC-004-2.1 – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

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### A. Introduction

1. **Title:** Analysis and Mitigation of Transmission and Generation Protection System Misoperations
2. **Number:** PRC-004-2.1
3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.
4. **Applicability**
  - 4.1. Transmission Owner.
  - 4.2. Distribution Provider that owns a transmission Protection System.
  - 4.3. Generator Owner.
5. **(Proposed) Effective Date:** In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements become effective upon Board of Trustees' adoption.  
~~The first day of the first calendar quarter, one year after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year after Board of Trustees' adoption.~~

### B. Requirements

- R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- R2. The Generator Owner shall analyze its generator and generator interconnection Facility Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.

### C. Measures

- M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Entity's procedures.

### D. Compliance

1. **Compliance Monitoring Process**

**Standard PRC-004-2.1 – Analysis and Mitigation of Transmission and Generation Protection System Misoperations**

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**1.1. Compliance Enforcement Authority**

Regional Entity.

**1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

**1.3. Compliance Monitoring and Enforcement Processes:**

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.4. Data Retention**

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

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

**1.5. Additional Compliance Information**

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

**2. Violation Severity Levels (no changes)**

**E. Regional Differences**

None identified.

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
2	TBD	Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised.
<u>3</u>	<u>XX</u>	<u>Errata change: Edited R2 to add “...and</u>	<u>Revision under Project</u>

**Standard PRC-004-2.1 – Analysis and Mitigation of Transmission and Generation Protection System Misoperations**

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		<u>generator interconnection Facility...”</u>	<u>2010-07</u>
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# Implementation Plan for FAC-001-1—Facility Connection Requirements

## **Prerequisite Approvals**

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

## **Revision to Sections of Approved Standards and Definitions**

There are no proposed revisions to requirements in other already approved standards. FAC-001-0 – Facility Connection Requirements will be retired at midnight the day before FAC-001-1 becomes effective.

## **Compliance with Standard**

Since this version of the standard imposes no changes to Transmission Owners from those in the FERC-approved version of the standard, the expectation is that Transmission Owners will maintain their current state of compliance. Thus, the standard is effective for Transmission Owners upon approval, as detailed below.

The proposed changes to the FERC-approved version of this standard only address Generator Owner applicability and requirements (add Generator Owner to section 4.2, introduce a new requirement (R2), and modify one existing requirement (now R3)). Therefore, this implementation plan only identifies a compliance timeframe for Generator Owners to which this standard will apply.

## **Effective Date**

There are two effective dates associated with this standard:

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner and Regional Entity become effective upon Board of Trustees' adoption.

In those jurisdictions where regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities. In those jurisdictions where no regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after Board of Trustees' adoption.



# Implementation Plan for FAC-001-1 Facility Connection Requirements

## Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

## Revision to Sections of Approved Standards and Definitions

There are no proposed revisions to requirements in other already approved standards. FAC-001-0 Facility Connection Requirements will be retired ~~when~~ at midnight the day before FAC-001-1 becomes effective.

## Compliance with Standard

Since this version of the standard imposes no changes to Transmission Owners from those in the FERC-approved version of the standard, the expectation is that Transmission Owners will maintain their current state of compliance. Thus, the standard is effective for Transmission Owners upon approval, as detailed below.

The proposed changes to the FERC-approved version of this standard only address Generator Owner applicability and requirements (add Generator Owner to section 4.2, introduce a new requirement (R2), and modify ~~two~~ one existing ~~requirements~~ requirement (now R3 ~~and~~ R4)). Therefore, this implementation plan only identifies a compliance timeframe for Generator Owners to which this standard will apply.

## Effective Date

There are two effective dates associated with this standard:

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner and Regional Entity become effective upon Board of Trustees' adoption.

In those jurisdictions where regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities. In those jurisdictions where no regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after Board of Trustees' adoption.

# Implementation Plan for FAC-003-3— Transmission Vegetation Management

## Prerequisite Approvals

There are a number of scenarios that could occur regarding the approval of FAC-003-2 that would affect the implementation of FAC-003-3.

If FAC-003-2 is filed with applicable regulatory authorities and approved before FAC-003-3 is filed with applicable regulatory authorities, then when and if FAC-003-3 is approved by applicable regulatory authorities, the implementation plan and effective dates for Transmission Owners in FAC-003-2 will be transferred into this implementation plan. The “clock” for calculating effective dates for Transmission Owners will still have started at the time specified in FAC-003-2 (based on the approval date of that standard). Generator Owners will be required to comply with the implementation plan as outlined below.

If applicable regulatory authorities elect to approve only FAC-003-3 and not FAC-003-2, the original implementation plan for Transmission Owners as outlined in FAC-003-2 will be transferred into this implementation plan. Generator Owners will be required to comply with the implementation plan as outlined below. The “clocks” for calculating the effective dates for both Transmission Owners and Generator Owners will begin at the same time.

If applicable regulatory authorities approve FAC-003-2 and FAC-003-3 at the same time, the implementation plan and effective dates for Transmission Owners in FAC-003-2 will be transferred into this implementation plan and FAC-003-2 will be immediately retired. Generator Owners will be required to comply with the implementation plan as outlined below. The “clocks” for calculating the effective dates for both Transmission Owners and Generator Owners will begin at the same time.

## Revision to Sections of Approved Standards and Definitions

There are no proposed revisions to requirements in other already approved standards. All requirements and the two revised definitions in the proposed standard FAC-003-2 will be retired at midnight the day before FAC-003-3 becomes effective.

There are two revised definitions in the proposed standard:

### Right-of-Way (ROW)

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either

construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria.

### **Vegetation Inspection**

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

There is one new definition in the proposed standard:

### **Minimum Vegetation Clearance Distance (MVCD)**

The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

The current glossary definitions of Right-of-Way and Vegetation Inspection, or the glossary definitions of Right-of-Way and Vegetation Inspection in FAC-003-2, if that standard has been approved, will be retired at midnight the day before FAC-003-3 (and with it, the above definitions of Right-of-Way and Vegetation Inspection) becomes effective. The above definition of Minimum Vegetation Clearance Distance will be added to the NERC glossary upon approval of FAC-003-3, or the above definition of Minimum Vegetation Clearance Distance will replace (and thus force the retirement, at midnight the day before FAC-003-3 is approved) of the same definition in FAC-003-2, if FAC-003-2 has been approved.

### **Compliance with Standard**

As outlined above under "Prerequisite Approvals," the inclusion of Transmission Owners in this implementation plan will depend on order in which regulatory authorities approved FAC-003-2 and FAC-003-3. Therefore, this implementation plan only identifies a compliance timeframe for Generator Owners to which this standard will apply.

To reach compliance with the standard, a Generator Owner will have to perform a full review of as-built drawings and determine which generation interconnection Facilities require a Transmission Vegetation Management Plan (TVMP) and inspection as specified by NERC Reliability Standard FAC-003-3. In general, Generator Owners do not have staff that are qualified and experienced to create a TVMP, perform Right-of-Way inspections, and perform any required tree trimming (as is required by FAC-003-3 Requirement 1.3). Once a complete inventory is created, the Generator Owner will begin the process of gathering information for the TVMP. In instances where the generation interconnection Facilities are owned by a partnership, a majority or operating partner will need to obtain partnership

approval to proceed with procurement of a TVMP expert, and later a tree trimming crew. Typically, a request for proposal to hire TVMP consultant is initiated which could take several weeks in order to obtain sufficient bids (and also satisfy Sarbanes Oxley requirements). Once all bids have been received, a contract with a TVMP consultant is signed. At this point, the TVMP consultant and Generator Owner staff will develop the TVMP, which needs to take into account local growth conditions, types of vegetation and other aspects required by FAC-003. Once the TVMP is developed, Generator Owner staff and the TVMP consultant will need to perform a Right-of-Way inspection (as required in FAC-003-3 Requirement 1), usually done using GPS, LIDAR and other tools by experienced and qualified staff.

Once a Right-of-Way inspection is completed and clearances are required, the Generator Owner will need to issue a request for proposal to hire a tree trimming crew that is qualified and experienced to perform required clearance trimming. Once all bids have been received, a contract with a tree trimming crew is signed. When the tree trimming crew is acquired, the crew will need to familiarize themselves with the entity's TVMP and required clearances. The Generator Owner will typically need to schedule any required outages in order for the tree trimming crew to perform the needed clearance trimming. This action would also include the implementation of the work plan as required in FAC-003-3 Requirement 2. During scheduled outages, if required, the tree trimming crew will perform any required clearances and document the activities.

Another typical action is the Generator Owner establishing a system for maintaining TVMP-related activities, including maintenance of inspection and clearance documentation (as required in FAC-003-3 Requirement 1.2). On an ongoing basis, in addition to performing inspections and clearances as required by the entity's TVMP, the Generator Owner will need to ensure that the training and qualification requirements for the standard are met. The entity will also need to maintain documentation of all FAC-003-3 activities for compliance period of one year to meet compliance with the standard.

Again, due to a typical lack of experience and qualifications required by FAC-003-3, compliance with this standard by a Generator Owner may take as long as two years – in part because many entities will have generator interconnection Facilities in various parts of the country which may require several instances of TVMP and numerous Right-of-Way inspections.

### **Effective Date**

There are two effective dates associated with this implementation plan:

The first effective date allows Generator Owners time to develop documented maintenance strategies or procedures or processes or specifications as outlined in Requirement R3.

In those jurisdictions where regulatory approval is required, Requirement R3 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one

year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The second effective date allows entities time to comply with Requirements R1, R2, R4, R5, R6, and R7.

In those jurisdictions where regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.
2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.
3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.
4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.
5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12

months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.



# Implementation Plan for FAC-003-3 — Transmission Vegetation Management

## Prerequisite Approvals

There are a number of scenarios that could occur regarding the approval of FAC-003-2 —Vegetation Management must be implemented that would affect the implementation of FAC-003-3.

If FAC-003-2 is filed with applicable regulatory authorities and approved before FAC-003-3 is filed with applicable regulatory authorities, then when and if FAC-003-3 is approved by applicable regulatory authorities, the implementation plan and effective dates for Transmission Owners in FAC-003-2 will be transferred into this implementation plan. The “clock” for calculating effective dates for Transmission Owners will still have started at the time specified in FAC-003-2 (based on the approval date of that standard ~~can~~). Generator Owners will be implemented required to comply with the implementation plan as outlined below.

If applicable regulatory authorities elect to approve only FAC-003-3 and not FAC-003-2, the original implementation plan for Transmission Owners as outlined in FAC-003-2 will be transferred into this implementation plan. Generator Owners will be required to comply with the implementation plan as outlined below. The “clocks” for calculating the effective dates for both Transmission Owners and Generator Owners will begin at the same time.

If applicable regulatory authorities approve FAC-003-2 and FAC-003-3 at the same time, the implementation plan and effective dates for Transmission Owners in FAC-003-2 will be transferred into this implementation plan and FAC-003-2 will be immediately retired. Generator Owners will be required to comply with the implementation plan as outlined below. The “clocks” for calculating the effective dates for both Transmission Owners and Generator Owners will begin at the same time.

## Revision to Sections of Approved Standards and Definitions

There are no proposed revisions to requirements in other already approved standards. All requirements and the two revised definitions in the proposed standard FAC-003-2 will be retired when at midnight the day before FAC-003-3 becomes effective.

There are two revised definitions in the proposed standard:

### Right-of-Way (ROW)

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either

construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria.

### **Vegetation Inspection**

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

There is one new definition in the proposed standard:

### **Minimum Vegetation Clearance Distance (MVCD)**

The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

The current glossary definitions of Right-of-Way and Vegetation Inspection, or the glossary definitions of Right-of-Way and Vegetation Inspection in FAC-003-2, if that standard has been approved, will be retired at midnight the day before FAC-003-3 (and with it, the above definitions of Right-of-Way and Vegetation Inspection) becomes effective. The above definition of Minimum Vegetation Clearance Distance will be added to the NERC glossary upon approval of FAC-003-3, or the above definition of Minimum Vegetation Clearance Distance will replace (and thus force the retirement, at midnight the day before FAC-003-3 is approved) of the same definition in FAC-003-2, if FAC-003-2 has been approved.

### **Compliance with Standard**

~~There are no changes to~~ As outlined above under "Prerequisite Approvals," the requirements applicable to inclusion of Transmission Owners already proposed in this implementation plan will depend on order in which regulatory authorities approved FAC-003-2, and the expectation is that Transmission Owners will maintain their current state of compliance. Thus, the standard is effective for Transmission Owners upon approval, as detailed below.

~~The proposed changes to Version 2 of the standard only address Generator Owner applicability and requirements (add Generator Owner to sections 4.1.2 and 4.FAC-003-3 and add applicable Generator Owner to all requirements).~~ Therefore, this implementation plan only identifies a compliance timeframe for Generator Owners to which this standard will apply.

To reach compliance with the standard, a Generator Owner will have to perform a full review of as-built drawings and determine which generation interconnection Facilities require a Transmission



Vegetation Management Plan (TVMP) and inspection as specified by NERC Reliability Standard FAC-003-3. In general, Generator Owners do not have staff that are qualified and experienced to create a TVMP, perform Right-of-Way inspections, and perform any required tree trimming (as is required by FAC-003-3 Requirement 1.3). Once a complete inventory is created, the Generator Owner will begin the process of gathering information for the TVMP. In instances where the generation interconnection Facilities are owned by a partnership, a majority or operating partner will need to obtain partnership approval to proceed with procurement of a TVMP expert, and later a tree trimming crew. Typically, a request for proposal to hire TVMP consultant is initiated which could take several weeks in order to obtain sufficient bids (and also satisfy Sarbanes Oxley requirements). Once all bids have been received, a contract with a TVMP consultant is signed. At this point, the TVMP consultant and Generator Owner staff will develop the TVMP, which needs to take into account local growth conditions, types of vegetation and other aspects required by FAC-003. Once the TVMP is developed, Generator Owner staff and the TVMP consultant will need to perform a Right-of-Way inspection (as required in FAC-003-3 Requirement 1), usually done using GPS, LIDAR and other tools by experienced and qualified staff.

Once a Right-of-Way inspection is completed and clearances are required, the Generator Owner will need to issue a request for proposal to hire a tree trimming crew that is qualified and experienced to perform required clearance trimming. Once all bids have been received, a contract with a tree trimming crew is signed. When the tree trimming crew is acquired, the crew will need to familiarize themselves with the entity's TVMP and required clearances. The Generator Owner will typically need to schedule any required outages in order for the tree trimming crew to perform the needed clearance trimming. This action would also include the implementation of the work plan as required in FAC-003-3 Requirement 2. During scheduled outages, if required, the tree trimming crew will perform any required clearances and document the activities.

Another typical action is the Generator Owner establishing a system for maintaining TVMP-related activities, including maintenance of inspection and clearance documentation (as required in FAC-003-3 Requirement 1.2). On an ongoing basis, in addition to performing inspections and clearances as required by the entity's TVMP, the Generator Owner will need to ensure that the training and qualification requirements for the standard are met. The entity will also need to maintain documentation of all FAC-003-3 activities for compliance period of one year to meet compliance with the standard.

Again, due to a typical lack of experience and qualifications required by FAC-003-3, compliance with this standard by a Generator Owner may take as long as two years – in part because many entities will have generator interconnection Facilities in various parts of the country which may require several instances of TVMP and numerous Right-of-Way inspections.

### Effective Date

There are ~~three~~two effective dates associated with this implementation plan:

~~116-390 Village Blvd.  
Princeton, NJ 08540~~

~~609.452.8060~~ | ~~www.nerc.com~~ **Implementation Plan for FAC-003-3**

The first ~~effective date applies to Transmission Owners.~~

~~In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner become effective upon Board of Trustees' adoption.~~

The ~~second~~ effective date allows Generator Owners time to develop documented maintenance strategies or procedures or processes or specifications as outlined in Requirement R3.

In those jurisdictions where regulatory approval is required, Requirement R3 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The ~~third~~ second effective date allows entities time to comply with Requirements R1, R2, R4, R5, R6, and R7.

In those jurisdictions where regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

#### Exceptions:

##### Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or as designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being ~~subject~~ an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to ~~this~~ become an element of an IROL or an element of a Major WECC Transfer Path.

2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.
3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.
4. An existing transmission line operated at 200kV or higher ~~that~~which is newly acquired by an asset owner and which was not previously subject to this standard; becomes subject to this standard 12 months after the acquisition date ~~of the line.~~
5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

## **Implementation Plan for FAC-003-X – Transmission Vegetation Management Program**

### **Prerequisite Approvals**

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

### **Revision to Sections of Approved Standards and Definitions**

There are no proposed revisions to requirements in other already approved standards. FAC-003-1 will be retired at midnight the day before FAC-003-X becomes effective.

There is one revised definition in the proposed standard:

**Right-of-Way:** A corridor of land on which electric lines may be located. The Transmission Owner or applicable Generator Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

The current glossary definition of Right-of-Way will be retired at midnight the day before FAC-003-X (and with it, the above definition of Right-of-Way) becomes effective.

### **Compliance with Standard**

There are no changes to the requirements applicable to Transmission Owners already in effect in FAC-003-1, and the expectation is that Transmission Owners will maintain their current state of compliance. Thus, the standard is effective for Transmission Owners upon approval, as detailed below.

The proposed changes to FAC-003-1 only address Generator Owner applicability and requirements (add Generator Owner to section 4.3 and add applicable Generator Owner to all requirements). Therefore, this implementation plan only identifies a compliance timeframe for Generator Owners to which this standard will apply.

To reach compliance with the standard, a Generator Owner will have to perform a full review of as-built drawings and determine which generation interconnection Facilities require a Transmission Vegetation Management Plan (TVMP) and inspection as specified by NERC Reliability Standard FAC-003-X. In general, Generator Owners do not have staff that are qualified and experienced to create a TVMP and implement annual plans for vegetation management. Once a complete inventory is created, the Generator Owner will begin the process of gathering information for the TVMP. In instances where the generation interconnection Facilities are owned by a partnership, a majority or operating partner will need to obtain partnership approval to proceed with procurement of a TVMP expert, and later a tree trimming crew. Typically, a request for proposal to hire TVMP consultant is initiated, which could take several weeks in order to obtain sufficient bids (and also satisfy Sarbanes Oxley requirements). Once all bids have been received, a contract with a TVMP consultant is signed. At this point, the TVMP consultant and

Generator Owner staff will develop the TVMP, which needs to take into account local growth conditions, types of vegetation and other aspects required by FAC-003-X. Once the TVMP is developed, Generator Owner staff and the TVMP consultant will need to perform a Right-of-Way inspection, usually done using GPS, LIDAR and other tools by experienced and qualified staff.

Once a Right-of-Way inspection is completed and clearances are required, the Generator Owner will need to issue a request for proposal to hire a tree trimming crew that is qualified and experienced to perform required clearance trimming. Once all bids have been received, a contract with a tree trimming crew is signed. When the tree trimming crew is acquired, the crew will need to familiarize themselves with the entity's TVMP and required clearances. The Generator Owner will typically need to schedule any required outages in order for the tree trimming crew to perform the needed clearance trimming. This action would also include the implementation of the work plan. During scheduled outages, if required, the tree trimming crew will perform any required clearances and document the activities.

Another typical action is the Generator Owner establishing a system for maintaining TVMP-related activities, including maintenance of inspection and clearance documentation. On an ongoing basis, in addition to performing inspections and clearances as required by the entity's TVMP, the Generator Owner will need to ensure that the training and qualification requirements for the standard are met. The entity will also need to maintain documentation of all FAC-003-X activities for compliance period of one year to meet compliance with the standard.

Again, due to a typical lack of experience and qualifications required by FAC-003-X, compliance with this standard by a Generator Owner may take as long as two years – in part because many entities will have generator interconnection Facilities in various parts of the country which may require several instances of TVMP and numerous Right-of-Way inspections.

### **Effective Date**

There are three effective dates associated with this implementation plan:

The first effective date applies to Transmission Owners.

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner become effective upon Board of Trustees' adoption.

The second effective date allows Generator Owners time to prepare a formal transmission vegetation management program as outlined in Requirement R1.

In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The third effective date allows entities time to comply with Requirements R2, R3, and R4.

In those jurisdictions where regulatory approval is required, Requirements R2, R3, and R4 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R2, R3, and R4 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

## Implementation Plan for FAC-003-X – Transmission Vegetation Management Program

### Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

### Revision to Sections of Approved Standards and Definitions

There are no proposed revisions to requirements in other already approved standards.

FAC-003-1 will be retired ~~when~~ at midnight the day before FAC-003-~~2~~X becomes effective.

There is one revised definition in the proposed standard:

**Right-of-Way:** A corridor of land on which electric lines may be located. The Transmission Owner or applicable Generator Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

The current glossary definition of Right-of-Way will be retired at midnight the day before FAC-003-X (and with it, the above definition of Right-of-Way) becomes effective.

### Compliance with Standard

There are no changes to the requirements applicable to Transmission Owners already in effect in FAC-003-1, and the expectation is that Transmission Owners will maintain their current state of compliance. Thus, the standard is effective for Transmission Owners upon approval, as detailed below.

The proposed changes to FAC-003-1 only address Generator Owner applicability and requirements (add Generator Owner to section 4.3 and add applicable Generator Owner to all requirements). Therefore, this implementation plan only identifies a compliance timeframe for Generator Owners to which this standard will apply.

To reach compliance with the standard, a Generator Owner will have to perform a full review of as-built drawings and determine which generation interconnection Facilities require a Transmission Vegetation Management Plan (TVMP) and inspection as specified by NERC Reliability Standard FAC-003-X. In general, Generator Owners do not have staff that are qualified and experienced to create a TVMP and implement annual plans for vegetation management. Once a complete inventory is created, the Generator Owner will begin the process of gathering information for the TVMP. In instances where the generation interconnection Facilities are owned by a partnership, a majority or operating partner will need to obtain partnership approval to proceed with procurement of a TVMP expert, and later a tree trimming crew. Typically, a request for proposal to hire TVMP consultant is initiated, which could take several weeks in order to obtain sufficient bids (and also satisfy Sarbanes Oxley requirements). Once all bids have been received, a

contract with a TVMP consultant is signed. At this point, the TVMP consultant and Generator Owner staff will develop the TVMP, which needs to take into account local growth conditions, types of vegetation and other aspects required by FAC-003-X. Once the TVMP is developed, Generator Owner staff and the TVMP consultant will need to perform a Right-of-Way inspection, usually done using GPS, LIDAR and other tools by experienced and qualified staff.

Once a Right-of-Way inspection is completed and clearances are required, the Generator Owner will need to issue a request for proposal to hire a tree trimming crew that is qualified and experienced to perform required clearance trimming. Once all bids have been received, a contract with a tree trimming crew is signed. When the tree trimming crew is acquired, the crew will need to familiarize themselves with the entity's TVMP and required clearances. The Generator Owner will typically need to schedule any required outages in order for the tree trimming crew to perform the needed clearance trimming. This action would also include the implementation of the work plan. During scheduled outages, if required, the tree trimming crew will perform any required clearances and document the activities.

Another typical action is the Generator Owner establishing a system for maintaining TVMP-related activities, including maintenance of inspection and clearance documentation. On an ongoing basis, in addition to performing inspections and clearances as required by the entity's TVMP, the Generator Owner will need to ensure that the training and qualification requirements for the standard are met. The entity will also need to maintain documentation of all FAC-003-X activities for compliance period of one year to meet compliance with the standard.

Again, due to a typical lack of experience and qualifications required by FAC-003-X, compliance with this standard by a Generator Owner may take as long as two years – in part because many entities will have generator interconnection Facilities in various parts of the country which may require several instances of TVMP and numerous Right-of-Way inspections.

### **Effective Date**

There are three effective dates associated with this implementation plan:

The first effective date applies to Transmission Owners.

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner become effective upon Board of Trustees' adoption.

The second effective date allows Generator Owners time to prepare a formal transmission vegetation management program as outlined in Requirement R1.



In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The third effective date allows entities time to comply with Requirements R2, R3, and R4.

In those jurisdictions where regulatory approval is required, Requirements R2, R3, and R4 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R2, R3, and R4 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

# Implementation Plan for PRC-004-2.1— Analysis of Transmission and Generation Protection System Misoperations

## **Prerequisite Approvals**

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

## **Revision to Sections of Approved Standards and Definitions**

There are no proposed revisions to requirements in other already approved standards. PRC-004-2 will be retired when PRC-004-2.1 becomes effective.

## **Compliance with Standard**

The proposed change to Requirement R2 is a clarifying change. While there was no reliability gap in the previous version of the standard, if applied literally, there was the possibility for the misperception that the Generator Owner was only responsible for analyzing its generator Protection System Misoperations, exclusive of its generator interconnection Facility. The errata change to R2 makes clear that generator interconnection Facilities are also part of Generator Owners' responsibility in the context of this standard.

Because the change is merely a clarifying change, no additional time for compliance is needed.

## **Effective Date**

In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements become effective upon Board of Trustees' adoption.

# Technical Justification

## Project 2010-07 Generator Requirements at the Transmission Interface

### Background

As part of its work on Project 2010-07—Generator Requirements at the Transmission Interface, the standard drafting team (SDT) reviewed 34 reliability standards and 102 requirements to determine what changes are necessary to close a reliability gap with respect to what is commonly known as the generator interconnection Facility. The majority of these standards and requirements had been addressed in the [Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface](#) (Ad Hoc Report), and additional standards have been reviewed, and will continue to be reviewed, as a result of informal discussions with NERC and FERC staffs.

The basis for standard modifications recommended by the Ad Hoc Group for Generator Requirements at the Transmission Interface (Ad Hoc Group) was a few fundamental clarifications to the definitions of Generator Owner, Generator Operator, and Transmission, along with the creation of new definitions: one for Generator Interconnection Facility and one for Generator Interconnection Operational Interface. The Ad Hoc Group proposed the addition of these two new definitions to 26 standards encompassing 29 requirements (new and old), along with some modifications to FAC-003 to make it applicable to Generator Owners under certain circumstances.

Since the publication of the Ad Hoc Report, various entities have challenged these modifications and the recommended creation of the new definitions. The SDT has developed a more focused approach than that of the Ad Hoc Group: to propose recommendations whereby radial interconnection Facilities (at or above 100 kV) that are owned and operated by generating entities will be included in a small set of standards and requirements previously only applicable to Transmission Owners. The SDT agrees completely with the Ad Hoc Group's conclusion that Generator Owners and Operators of these radial generator tie-line Facilities (at voltages equal to or greater than 100 kV) should not be registered as Transmission Owners and Transmission Operators in order to maintain reliability on the Bulk Electric System (BES).

The SDT's justification for this strategy is rooted in the very title of its standards project: "Generator Requirements at the Transmission Interface." That is, the goal and scope of the project has always been to determine the responsibilities of those Generator Owners and Generator Operators that own or operate an interconnection Facility (in some cases labeled a "transmission Facility") between the generator and the interface with the portion of the BES where Transmission Owners and Transmission Operators take over ownership and operating responsibility. These kinds of Generator Owners and Generator Operators do not own or operate Facilities that are part of the interconnected system; rather, they own and operate radial Facilities that are connected to the boundary of the

interconnected system and as such have a limited role in providing reliability compared to those that operate in a networked fashion beyond the point of interconnection.

While some argue that these interconnecting portions of a Generator Owner's Facilities could be defined as Transmission and thus require the Generator Owner and Generator Operator for the Facility to be classified and registered as a Transmission Owner and Transmission Operator, the SDT does not believe this is necessary to provide an appropriate level of reliability for the BES. Just as important, such classification and registration could actually cause a reduction in reliability. Generator Owners and Generator Operators do not need, and in some cases may be prohibited from having, a wide-area view and responsibility for the integrated transmission system. Requiring Generator Owners and Generator Operators to have such responsibilities would require significant training, would require substantially more data and modeling responsibilities, and would detract from the entities' primary functions: to own and operate their generation equipment – including any Facilities owned and operated at voltages of 100 kV or greater that connect to the interconnected system – in a reliable manner.

Additionally, the SDT believes that the industry is much more aware today of the need to include all elements (owned and operated at 100 kV or higher) of a generator Facility in the procedures and compliance program of the registered entity that owns or has operational responsibility of those elements. Industry awareness was raised substantially at the time the [October 17, 2010 Facility Ratings Recommendation to Industry](#) was issued (which included Generator Owners and specifically addressed interconnection Facilities in [the Q&A document](#)). While this applies to a specific NERC Recommendation, the SDT considers this compelling evidence that the paradigm for thinking about generator interconnection Facilities is shifting.

All of this has led the SDT to its current conclusions to modify FAC-001, FAC-003, and PRC-004. The SDT does not believe any further modifications to standards are necessary to maintain an appropriate level of reliability based on the revised assumption that while generator Facilities (at 100 kV and above) will be considered by some to be transmission, Generator Owners and Generator Operators should not be registered as Transmission Owners and Transmission Operators simply as a result of the ownership and operation of such Facilities. Because the majority of commenters support the SDT's current recommendation to not adopt new terms, the SDT has elected to focus on its standard changes and to postpone discussions on revisions to existing, or creation of new, definitions until the standards have been successfully balloted.

Below, the SDT discusses the changes it has proposed for FAC-001, FAC-003, and PRC-004 and then provides justification for not modifying any additional standards that had been proposed for substantive modification in the Ad Hoc Report.

### **Review of SDT's Proposed Standard Changes**

### ***FAC-001-1—Facility Connection Requirements***

While some stakeholders have questioned the modifications in the proposed FAC-001-1, the SDT remains convinced that there is the potential for a reliability gap if this standard is not modified so that it applies to a Generator Owner if and when it executes an Agreement to evaluate the reliability impact of interconnecting a third party Facility to its existing generation interconnection Facility. The intent of this modified language is to start the compliance clock when the Generator Owner executes an Agreement to perform the reliability assessment required in FAC-002-1. This step is expected to occur if a Generator Owner is compelled by a regulatory body to allow such interconnection. Assuming that a regulatory body would require a Generator Owner to evaluate such an interconnection request, the SDT expects the Generator Owner and the third party to execute some form of an Agreement. The SDT intentionally excluded a specific reference to the form of Agreement (such as a feasibility study) in deference to stakeholder suggestions to avoid comingling of commercial and reliability issues in reliability standards.

The SDT acknowledges that the scenario described in the proposed FAC-001-1 may be rare, but in the past (for instance, FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities, and the SDT thinks it is important to clarify the responsibilities related to such a request in NERC's Reliability Standards. And, while the SDT acknowledges that such regulatory action might also result in the Generator Owner being registered for other functions, such as Transmission Owner, Transmission Planner, and/or Transmission Service Provider, it decided the proposed revision provides appropriate reliability coverage until any additional registration is required and does not impact any Generator Owner that never executes an Agreement as described in the standard.

### ***FAC-003-X and FAC-003-3—Vegetation Management***

The SDT and most stakeholders agree with the Ad Hoc Group recommendation that FAC-003 be applicable to Generator Owners that own a generation interconnection if that Facility contains overhead conductors. The Ad Hoc Group originally excluded such a Facility from this requirement if its length is less than two spans (generally one half mile from the generator property line). After reviewing formal comments, the SDT agreed to revise the exclusion so that it applies to a Facility if its length is "one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard" to approximate line of sign from a fixed point. Other than revising this exclusion, the SDT applied the same criteria to the Generator Owner as applies to the Transmission Owner in the current FERC approved version of this standard as well as one approved by stakeholders (under Project 2007-07) in February 2011. The SDT is communicating with NERC staff and the Project 2007-07 SDT to ensure that changes to this standard will be coordinated before submitting to NERC's Board of Trustees, but feels compelled to continue to posting both versions until the outcome of Project 2007-07 efforts is clearer.

### ***PRC-004-2.1—Analysis and Mitigation of Transmission and Generation Protection System Misoperations***

After examining all standards it had previously reviewed, the SDT elected to propose a slight change to PRC-004-2.1. While the SDT rejected other opportunities to “drop” the phrase “generator interconnection Facility” into requirements because it is not typically the best way to add clarity, in the case of PRC-004-2, the SDT fears that the phrasing of R2 (“The Generator Owner shall analyze its generator Protection System Misoperations...”) could lead to some confusion about whether an interconnection Facility is included. Thus, the SDT proposes adding “and generator interconnection Facility” as redlined in the draft standard. Because there is no change in applicability, and because the SDT believes that most Generator Owners already interpret the standard in this manner, we consider this to be a minor and not substantive change employed only to add clarity.

### **Review of Other Substantive Standard Modifications from the Ad Hoc Report**

To ensure that no reliability gaps were left when the SDT shifted its strategy from the original strategy of the Ad Hoc Group, the SDT reviewed all standards for which the Ad Hoc Group had proposed changes, and again discussed whether making these standards applicable to Generator Owners or Generator Operators would increase reliability with respect to generator requirements at the transmission interface. Below, the SDT provides its reasons for not proposing the substantive changes that were included in the Ad Hoc Report (that is, a change in applicability or new requirement, beyond simply adding the text “including its Generator Interconnection Facility” to an existing requirement). As Project 2010-07 continues, the SDT will work with FERC staff, NERC staff, and industry groups to determine if its list of proposed standards is supported industry-wide, and whether other standards need to be considered.

#### ***EOP-003-1—Load Shedding Plans***

For **EOP-003-1**, the Ad Hoc Group originally proposed that Generator Operators be added to the requirement that requires Transmission Operators and Balancing Authorities to coordinate automatic load-shedding throughout their areas. The SDT determined that this addition was unnecessary because PRC-001 already includes the requirement that Transmission Operators coordinate their underfrequency load shedding programs with underfrequency isolation of generating units, which infers that Generator Operators need to provide their underfrequency settings to their respective Transmission Operator. Further, Generator Operators typically do not have the technical expertise or access to the data necessary for the high-level coordination that this standard requires.

#### ***IRO-005-2—Reliability Coordination – Current Day Operations***

The SDT chose not to adopt the revision to **IRO-005-2** proposed by the Ad Hoc Group. This revision would have added a new requirement that would read, “The Generator Operator shall immediately inform the Transmission Operator of the status of the Special Protection System, including any degradation or potential failure to operate as expected for SPS relay or control equipment under its control.” The SDT initially arrived at this decision because of the planned retirement of IRO-005-2. In subsequent meetings, the SDT also reached the conclusion that there is no reliability gap as PRC-001-1 R2 already requires the Generator Operator to notify reliability entities of relay or equipment failures.



The SDT believes that a Special Protection System is a form of protection system and therefore any degradation or potential failure to operate as expected would be required to be reported by the Generator Operator to reliability entities (Balancing Authorities, Transmission Operators, and Reliability Coordinators).

#### *Personnel Performance, Training, and Qualifications (PER) Standards*

The SDT also chose not to propose the revisions to **PER-001-0—Operating Personnel Responsibility and Authority** or **PER-002-0—Operating Personnel Training** that were proposed by the Ad Hoc Group. For PER-001-0, the Ad Hoc Group had proposed adding a new R2 that would read “Each Generator Operator shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Generation Facility and Generation Interconnection Facility, and the responsibility and authority to follow the directives of reliability authorities including the Transmission Operator and Balancing Authority.” To PER-002-0, the Ad Hoc Group proposed adding the Generator Operator to R1 (“Each Transmission Operator, Generator Operator, and Balancing Authority shall be staffed with adequately trained operating personnel”) and adding a new R3 that would read: “Each Generator Operator shall implement an initial and continuing training program for all operating personnel that are responsible for operating the Generator Interconnection Facility that verifies the personnel’s ability and understanding to operate the equipment in a reliable manner.”

These proposed changes to the PER standards have little to do with responsibilities that relate specifically to a generator interconnection Facility. Issues related to the training of Generator Operators existed separately from the work of Project 2010-07, and the SDT agrees that its scope limits its efforts to standards that are directly related to generator requirements at the transmission interface. The SDT also cites past FERC Orders as proof that this issue is not within the scope of Project 2010-07. In Order 693, FERC directed NERC to "expand the applicability of the personnel training Reliability Standard, PER-002-0, to include (i) generator operators centrally-located at a generation control center with a direct impact on the reliable operation of the Bulk-Power System..." In Order 742, FERC reaffirmed this, stating that it is "not modifying the Order No. 693 directive regarding training for certain generator operator dispatch personnel, nor are we expanding a generator operator’s responsibilities."

Centrally-located generator operators working at a generation control center typically dispatch the output from multiple generating units. As such, they can be called upon to comply with orders from their Balancing Authority that may have a significant impact on the reliable operation of the BES. Their training would be covered by proposed change to PER-002-0 and Order 742. Generator Operators who deal with interconnection facilities at individual generating plants, on the other hand, typically do not receive reliability-based orders specific to the interconnection Facilities and are therefore not covered by Order 742. Further, the SDT believes there is no reliability gap as Generator Operators are, under

currently approved reliability standards, required to follow directives issued by a Balancing Authority, Reliability Coordinator or Transmission Operator.

These items are clearly important ones for the Commission, but the SDT does not think it is appropriate to fold modifications to these PER standards into the scope of its work until it is specifically directed to do so. For now, modifications to PER-002-0 based on Order 693 directives are already included in [NERC's Issue Database](#) (P. 52-53) to be addressed by a future project. PER-001-0 is not addressed in the Issues Database, but the [Project 2007-03 drafting team has proposed](#) that the standard be retired.

### *Transmission Operations (TOP) Standards*

For TOP standards, the Ad Hoc Group proposed a number of new requirements that the SDT does not see as supportive of reliability. This set of standards was somewhat difficult to analyze, as the Project 2007-03—Real-time Transmission Operations drafting team has made significant changes to TOP-001 through TOP-008, resulting in three proposed TOP standards where there are currently eight (see the project's [Implementation Plan](#)). The Project 2010-07 reviewed both the FERC-approved TOP standards and the fifth draft of the modified standards in Project 2007-03 to determine whether it needed to propose any additional changes to cover radial generator interconnection Facilities. In addition, the Project 2010-07 SDT contacted the Project 2010-07 to get its opinion as to whether there might be any reliability gaps related to generator interconnection facilities. No such changes will be proposed for the reasons outlined below.

The Ad Hoc Group proposed adding two new requirements to **TOP-001-1—Reliability Responsibilities and Authority**. The first was proposed as R9 and read: "The Generator Operator shall coordinate the operation of its Generator Interconnection Facility with the Transmission Operator to whom it interconnects in order to preserve Interconnection reliability..." The SDT does not agree that this change is necessary. TOP-002-2 R3 (proposed to be covered in the future by TOP-003-2, as outlined in Project 2007-03's Implementation Plan) already requires the Generator Operator to coordinate its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. These entities are, in turn, required to coordinate with their respective Transmission Operator. Additionally, TOP-002-2 R4 (proposed to be covered in the future by TOP-003-2, as outlined in Project 2007-03's Implementation Plan) requires each Balancing Authority and Transmission Operator to coordinate with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator. With these requirements, Generator Operators are already required to provide necessary operations information to Transmission Operators. To require the same thing in TOP-001-1 would be redundant.

The second new requirement proposed by the Ad Hoc Group for TOP-001-1 was R10, which was to read: "The Transmission Operator shall have decision-making authority over operation of the Generator Interconnection Operational Interface at all times in order to preserve Interconnection reliability." As cited above, TOP-002-2 R3 (proposed to be covered in the future by TOP-003-2, as



outlined in Project 2007-03's Implementation Plan) already requires the Generator Operator to coordinate with its interconnecting Transmission Operator. Further, TOP-001-1 R3 (proposed to be covered in the future in the proposed IRO-001-2 R2 and R3) already requires the Generator Operator to comply with reliability directives issued by the Transmission Operator. These requirements effectively give the Transmission Operator decision-making authority over operation of all generator Facilities up to the point of interconnection. To require the same thing in TOP-001-1 would be redundant.

The Ad Hoc Group also proposed a new requirement, R7, for **TOP-004-2—Transmission Operations** that would read: "The Generator Operator shall operate its Generator Interconnection Facility within its applicable ratings." The SDT does not agree that a reliability gap exists, because an operator has a fiduciary obligation to protect a Facility for which it is operationally responsible. FAC-008-1—Facility Ratings Methodology and FAC-009-1—Establish and Communicate Facility Ratings already infer that the reason for establishing a ratings methodology and communicating facility ratings to the Reliability Coordinator, Planning Authority, Transmission Planner, and Transmission Operator is "...for use in reliable planning and operation of the Bulk Electric System." Further, TOP-004-2 is proposed to be retired under the work of the Project 2007-03 drafting team. Its requirements will either be deleted or assigned elsewhere.

The Ad Hoc team proposed to add a new requirement, R5, to **TOP-008-1—Response to Transmission Limit Violations** that would read "The Generator Operator shall disconnect the Generator Interconnection Facility when safety is jeopardized or the overload or abnormal voltage or reactive condition persists and generating equipment or the Generator Interconnection Facility is endangered. In doing so, the Generator Operator shall notify its Transmission Operator and Balancing Authority impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter." The SDT sees no reliability benefit to adding this requirement. TOP-001-1 R7 ("Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless...") and its parts give the Generator Operator authority over its Facilities, which would include the generator interconnection Facility. If there is an outage, R7.1 requires the Generator Operator to notify and coordinate with its Transmission Operator, which is required to notify the Reliability Coordinator and other affected Transmission Operators. And as with TOP-004-2, the Project 2007-03 drafting team has proposed to deleting all of TOP-008-1's requirements and retiring the standard.

## Conclusion

The Project 2010-07 SDT is confident that the changes it has proposed address the reliability gap that exists with respect to the responsibilities of Generator Owners and Generator Operations that own radial interconnection Facilities. The changes to FAC-001 and FAC-003 (and now PRC-004) have been supported by stakeholders during comment periods, and there has been no strong support for bringing other standards into the scope of this project.

That said, the SDT recognizes the success of its work depends on stakeholders, NERC, and FERC agreeing that generator requirements at the transmission interface are covered under NERC Reliability Standards, both for the sake of reliability and to prevent further unwarranted registration of Generator Owners and Generator Operators as Transmission Owners and Transmission Operators. If the SDT's work does not close the gap in the eyes of all parties, that work will have been unsuccessful, so the SDT is considering all feedback it receives with request to this project. While it is posting changes to only FAC-001, FAC-003, and PRC-004, and stands by that decision, it will continue to consider whether glossary term additions/modifications and modifications to other standards could enhance the reliability impact of this project. Based on conversations with NERC and FERC staff, and review of FERC's Order Denying Compliance Registry Appeals of Cedar Creek Wind Energy and Milford Wind Corridor Phase I (135 FERC ¶ 61,241), the SDT is discussing whether it should consider the following requirements for further review: EOP-005-1 R1, R2, R6, R7; FAC-014-2 R2; PER-003-1 R1, R1.1, R1.2; PRC-001-1 R2, R2.2, R4, R6; PRC-004-1 R1; TOP-001 R1; TOP-004-2 R6, R6.1, R6.2, R6.3, R6.4; and TOP-006-1 R3. The SDT is actively seeking stakeholder feedback as to whether, in light of these orders, it should consider additional standards and or new or modifications to existing definitions as it proceeds with its work.

## Technical Justification: FAC-001-1

Project 2010-07 Generator Requirements at the Transmission Interface

In response to the June 17-July 17, 2011 formal posting of the proposed standard changes in Project 2010-07, the standard drafting team (SDT) received stakeholder comments on FAC-001-1 expressing concern about the feasibility of a Generator Owner receiving and executing an interconnection request on one of its interconnection Facilities, as well as concern about the market-related processes that would go along with such an interconnection request. In this technical justification document, the SDT seeks to further clarify its rationale for making the proposed FAC-001-1 applicable to qualifying Generator Owners.

While the SDT understands that interconnection requests for Generator Owner Facilities are still relatively rare, in the past (for instance, 134 FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities. The SDT acknowledges that FERC does not have jurisdiction over all Generator Owners, but realizes that the potential exists for a third party to request to interconnect its planned generator with an existing generator interconnection Facility (whose use at the time of the request is solely to transmit capacity, energy, and ancillary services from the existing generator).

The SDT discussed the various ways such an interconnection could occur and agrees that if the third party interconnection could be accomplished without the need for the existing Generator Owner to develop its own connection requirements and system performance requirements and determine impacts on the interconnected transmission systems, this standard need not apply to the Generator Owner. And the SDT agrees that in many cases, these connection requirements, system performance requirements, and determined impacts on the interconnected transmission systems are currently determined by entities registered as either a Transmission Owner, Transmission Planner, and/or Transmission Service Provider. However, the SDT remains convinced (based on the orders cited above) that there may be occasions where FERC or another regulatory agency compels the Generator Owner to allow a third party to interconnect its planned generator with an existing generator interconnection Facility. Where this occurs, the SDT feels it is necessary for the existing owner of that generator interconnection Facility to provide connection requirements to the third party that requests interconnection. The SDT also believes, and many comments seem to support, that performance requirements and a determination of impact to the interconnected transmission systems need to be evaluated by some entity. The question becomes which entity.

The SDT can only work within the standards development process. We cannot address other regulatory issues such as FERC-mandated open transmission access (Order 888 and subsequent) or state or provincial jurisdiction over generation or transmission assets. While we acknowledge these

mechanisms exists and may come into play in the scenarios described in the proposed FAC-001-1, we as the SDT can only deal within the context of reliability standards. For this reason, R2 indicates that FAC-001-1 applies only when a Generator Owner has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility. The SDT's reasoning here is that if the owner of the existing generator interconnection Facility agrees, or is compelled, to allow a third party to interconnect, and can do so using existing agreements, contracts, and/or tariffs (and thereby avoid having an executed Agreement to evaluate the reliability impact of interconnecting third party Facility to the Generator Owner's existing Facility), and thus avoid having to develop its own connection requirements or perform impact studies, it will. In this example, it is likely that the existing Transmission Owner, Transmission Planner, and/or Transmission Service Provider processes and Agreements will be utilized and the purpose of FAC-001-1 will be met without applying this standard to the Generator Owner.

If, on the other hand, the owner of the existing generator interconnection Facility agrees, or is compelled, to allow a third party to interconnect, but cannot do so without having to develop its own connection requirements or perform impact studies, the SDT believes that the potential for a reliability gap exists. This might occur, for instance, if the owner of an existing generator interconnection Facility was compelled to allow interconnection and to implement open transmission access. In this example, (under FERC Order 888 and subsequent orders), the existing interconnection owner becomes a Transmission Service Provider and is required to have an Open Access Transmission Tariff (OATT). FERC's pro forma OATT requires the Transmission Service Provider to, among other things, perform system impact and feasibility studies. In order to do so, such studies must be coordinated with other Transmission Service Providers and Transmission Planners. And, to further complicate the issue, the SDT has been informed that in Texas, a Generator Owner is not allowed to own transmission.

Clearly, these issues are complex and not all are within the jurisdiction of federal or provincial regulators. For these reasons, the SDT took the only approach it found workable. If, and only if, the existing owner of a generator interconnection Facility has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to its existing generation Facility would the proposed FAC-001-1 apply. The SDT believes that this is most likely to occur if the owner of an existing generator interconnection Facility is compelled to allow a third party to interconnect and adopt open transmission access. However, the SDT cannot be certain this is the only example and it therefore proposes to add this new requirement to FAC-001-1. In doing so, the SDT acknowledges that the Generator Owner may not, at the time it agrees or is compelled to allow a third party to interconnect, have the necessary expertise to conduct the required interconnect studies to meet this standard. However, the SDT believes that, upon executing such Agreement, the Generator Owner will have to acquire such expertise. How the Generator Owner chooses to do so is not for the SDT to determine. The SDT is tasked with identifying potential reliability gaps and addressing such gaps through the standards development process.

The SDT does agree with many comments asking that the Generator Owner not be required to maintain its connection requirements, and there was robust discussion among the team and observers. Some were concerned that, without an obligation to maintain, there would not be a review to ensure compliance with NERC Reliability Standards and applicable Regional Entity, subregional, Power Pool, and individual Transmission Owner planning criteria. Others were concerned that the third party requesting interconnection might not actually interconnect, but the owner of the existing generator interconnection Facility would, having executed an evaluation agreement, be forever obligated to maintain connection requirements. In the end, the SDT agreed that if the owner of the existing generator interconnection Facility adopted open access or was determined to be providing “transmission service” it was likely that its existing registration would be re-evaluated and that the issue would be more appropriately addressed at that time. The SDT has therefore agreed to remove maintenance requirements for Generator Owners from both Requirement R2 and Requirement R4 in the proposed FAC-001-1.

We hope that you have found this explanation of our rationale helpful, but if you have further suggestions for improvement or clarity, please submit them in your comments on this latest posting.

# Unofficial Comment Form

## Generator Requirements at the Transmission Interface (Project 2010-07)

Please **DO NOT** use this form to submit comments. Please use the [electronic comment form](#) to submit comments on the first formal posting for Project 2010-07—Generator Requirements at the Transmission Interface. The electronic comment form must be completed by **November 18, 2011**.

[2010-07 Project Page](#)

If you have questions please contact Mallory Huggins at [mallory.huggins@nerc.net](mailto:mallory.huggins@nerc.net) or 202-383-2629.

### Background

With the exception of the errata change to PRC-004-2.1, which is being posted for the first time, this is the second formal comment period and first ballot period for the standards included in Project 2010-07. The standards will be posted for formal comment for 45-days, with a ballot during the final 10 days of the comment period. Ballot pool formation will take place during the first 30 days of the comment period, and [the SDT is hosting an interactive webinar on October 6](#).

A 30-day formal comment period took place earlier this year, from June 17-July 17, 2011. The SDT thanks all those who provided feedback during that comment period. The SDT has reviewed and considered all comments submitted, and has incorporated many of them into its latest proposed standards, as explained in the Consideration of Comments form posted at the Project 2010-07 project page.

The purpose of Project 2010-07 is to ensure that all generator-owned Facilities are appropriately covered under NERC's Reliability Standards. While many Generator Owners and Generator Operators operate Elements and Facilities that are considered by some entities to be Transmission, these are most often radial Facilities that are not part of the integrated grid, and as such should not be subject to the same standards applicable to Transmission Owners and Transmission Operators who own and operate Transmission Elements and Facilities that are part of the integrated grid.

As part of the BES, generators affect the overall reliability of the BES. However, registering a Generator Owner or Generator Operator as a Transmission Owner or Transmission Operator, as has been the solution in some cases in the past, may decrease reliability by diverting the Generator Owner's or Generator Operator's resources from the operation of the equipment that actually produces electricity – the generation equipment itself.

The drafting team's goal is to ensure that an adequate level of reliability is maintained in the BES by clearly describing which standards need to be applied to generator interconnection Facilities that are not already applicable to Generator Owners or Generator Operators. The SDT believes this can be accomplished by properly applying FAC-001, FAC-003, and PRC-004-2.1 to Generator Owners as proposed in the redline standards posted for comment.

**NOTE:** The Project 2007-07 Vegetation Management team will likely be posting a sixth draft of FAC-003-2 for recirculation ballot during the Project 2010-07's comment period. Both teams acknowledge this overlap, and have been in contact to discuss best strategies moving forward. The

changes proposed by the Project 2010-07 SDT in FAC-003-3 are minimal, and serve only to apply the standard and its requirements to qualifying Generator Owners. The SDT recognizes that a number of scenarios may occur with respect to the filing and approval of Versions 2 and 3 of FAC-003 and has attempted to account for those in the FAC-003-3 implementation plan.

**You do not have to answer all questions. Enter all comments in Simple Text Format.**

1. Based on stakeholder comment, the SDT clarified the applicability language of FAC-001-1 and removed the Generator Owner from R4. Do you support the proposed redline changes to FAC-001-1? (Please refer to the posted FAC-001-1 technical justification document for more information about the SDT's rationale for its changes.)

Yes

No

Comments:

2. Do you support the one year compliance timeframe for Generator Owners as proposed in the Implementation Plan for FAC-001-1?

Yes

No

Comments:

3. With respect to FAC-003, many commenters focused on the half-mile qualifier in FAC-003. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: "...that extends greater than one mile beyond the fenced area of the generating station switchyard..." We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.

Taking into consideration that only one of the versions of FAC-003 will actually be implemented, a decision that will be made as Project 2007-07—Vegetation Management moves forward, do you support the proposed redline changes to FAC-003-X and FAC-003-3?

Yes

No

Comments:

4. Do you support compliance timeframe for Generator Owners as included and explained in the Implementation Plans for FAC-003-X?



Yes

No

Comments:

5. In the FAC-003-3 implementation plan, the SDT has attempted to account for a number of different scenarios that could play out with respect to the filing and approvals of FAC-003-2 and FAC-003-3. Do you support this approach? If there are other scenarios that the SDT needs to account for, please suggest them here.

Yes

No

Comments:

6. In its technical justification document, the SDT reviews all standards that had been proposed for substantive modification in the Ad Hoc Group's original support and explains why, with the exception of FAC-003, modifying them would not provide any reliability benefit. Do you support these justifications? If you believe the SDT needs to add more information to its rationale for any of these decisions, please include suggested language here.

Yes

No

Comments:

7. The SDT is attempting to modify a set of standards so that radial generator interconnection Facilities are appropriately accounted for in NERC's Reliability Standards, both to close reliability gaps and to prevent the unnecessary registration of GOs and GOPs at TOs and TOPs. Does the set of standards currently posted achieve this goal?

Yes

No

Comments:

8. If you answered "yes" to Question 7, are the modifications the SDT has made in this posting the appropriate ones?

Yes

No

Comments:

9. If you answered "no" to Question 7, what standards need to be added or removed to achieve the SDT's goal? Please provide technical justification for your answer.

Yes

No

Comments:



10. Do you have any other comments that you have not yet addressed? If yes, please explain.

Yes

No

Comments:

## Standards Announcement

Project 2010-07 Generator Requirements at the Transmission Interface  
Ballot Pool Forming October 5 – November 4, 2011

Formal Comment Period October 5 – November 18, 2011

Initial Ballot Windows Open November 9 – 18, 2011

### [Available Now](#)

The SDT has reviewed comments received during a 30-day formal comment period that took place earlier this year, from June 17-July 17, 2011, and thanks to all those who provided feedback during that comment period. The SDT has incorporated many of the suggested changes into its latest proposed standards, as explained in the posted Consideration of Comments.

This is the second formal comment period and initial ballot period for three standards included in Project 2010-07. Revised drafts of FAC-001-1 and two versions of FAC-003 – FAC-003-3 and FAC-003-X – along with minor modifications to PRC-004-2.1, have been posted for a formal comment period and initial ballot that will end on Friday, November 18, 2011. Note that FAC-003-X shows changes to the last approved version of the standard, while FAC-003-3 shows changes to the last version being developed by the Project 2007-07 drafting team to incorporate Requirements for Generator Owners in those standards.

PRC-004-2.1 is being posted for the first time with this posting, and is also being posted for a formal 45-day comment period with an initial ballot. Because the changes are very limited, the Standards Committee waived the initial formal comment period for this standard.

### **Instructions for Joining the Ballot Pool for Project 2010-07**

Registered Ballot Body members may join the ballot pool to be eligible to vote in the upcoming ballots at the following page: [Join Ballot Pool](#)

During the pre-ballot windows, members of the ballot pool may communicate with one another by using their “ballot pool list server.” (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) One ballot pool list server has been set up and can be used for communication on each of the standards being balloted for this project. The list server is: [bp-2010-07\\_FAC-001-1\\_in@nerc.com](mailto:bp-2010-07_FAC-001-1_in@nerc.com)

### Instructions for Commenting

Please use this [electronic form](#) to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at [monica.benson@nerc.net](mailto:monica.benson@nerc.net). An off-line, unofficial copy of the comment form is posted on the [project page](#).

### Next Steps

Separate ballots will be conducted for each standard. These ballot windows will begin on Wednesday, November 9, 2011 and end at 8 p.m. Eastern on Friday, November 18, 2011. NOTE: There is only one ballot pool to join for this project. There will be four separate ballots, one for each standard, and individuals who join this single ballot pool will be eligible to vote in all four ballots. This was done to make the process simpler for those who are voting. If you have any questions, please contact Monica Benson at [monica.benson@nerc.net](mailto:monica.benson@nerc.net).

### Background

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The drafting team's goal is to ensure that an adequate level of reliability is maintained in the BES by clearly describing which standards need to be applied to generator interconnection Facilities that are not already applicable to Generator Owners or Generator Operators. This can be accomplished by properly applying FAC-001, FAC-003, and PRC-004 to Generator Owners as proposed in the redline standards posted for comment.

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# Standards Announcement

## Project 2010-07 Generator Requirements at the Transmission Interface

Four Ballot Windows Now Open Through 8 p.m. Eastern on Friday, November 18, 2011

### Now Available

An initial ballot of each of the following standards is open through 8 p.m. Eastern on Friday, November 18, 2011. Note that the ballots are limited to the few modifications made to these standards to ensure that there is a functional entity responsible for requirements associated with the transmission line connecting the generator step up transformer to the transmission system (generator interconnection Facility).

- FAC-001-1 – Facility Connection Requirements
- Two versions of FAC-003 – Transmission Vegetation Management (FAC-003-3 and FAC-003-X). Note that FAC-003-X shows changes to FAC-003-1, while FAC-003-3 shows changes to FAC-003-2 developed by the Project 2007-07 drafting team. **FAC-003-2 was adopted by the NERC Board on November 3, and a revised version of FAC-003-3 showing the Project 2010-07 drafting team's changes against the Board's version has now been posted.**
- PRC-004-2.1 – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

### **IMPORTANT: Updates on Posted Standards**

Last week, while the Project 2010-07 standards were posted for comment, NERC's Board of Trustees adopted FAC-003-2 – Transmission Vegetation Management (developed under Project 2007-07 Vegetation Management). Based on this approval, NERC staff will file FAC-003-2 with the applicable regulatory authorities. The Project 2010-07 SDT will move forward with ballots for both FAC-003-3 (proposed changes to the BOT-adopted FAC-003-2) and FAC-003-X (proposed changes to the FERC-approved FAC-003-1) with the intention of eventually only filing FAC-003-3. The SDT has elected to carry FAC-003-X through to ballot because if FAC-003-2 and FAC-003-3 are not approved by FERC, the SDT wants to be ready to file FAC-003-X to ensure that there is a functional entity responsible for managing vegetation on the piece of line commonly known as the generator interconnection Facility.

Additionally, when the NERC Board of Trustees adopted FAC-003-2 –Transmission Vegetation Management last week, it approved the standard with NERC staff-proposed VSLs rather than the Project 2007-07 SDT-developed VSLs that were originally posted with both FAC-003-2 and FAC-003-3. The posted versions of Project 2010-07's FAC-003-3 now include the FAC-003-2 VSLs proposed by NERC

staff, since they are the set that was approved by the NERC Board of Trustees. Note that the Project 2010-07 SDT made no substantive changes to any version of the FAC-003-2 VSLs; the SDT simply changed “Transmission Owner” to “responsible entity.” A text box has also been added to the VSL section of FAC-003-3 for further clarity.

### **Instructions for Balloting**

Members of the ballot pools associated with this project may log in and submit their votes for the standards from the following page: <https://standards.nerc.net/CurrentBallots.aspx>

### **Instructions for Commenting**

A formal comment period is open through **8 p.m. Eastern on Friday, November 18, 2011**. Please use this [electronic form](#) to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at [monica.benson@nerc.net](mailto:monica.benson@nerc.net). An off-line, unofficial copy of the comment form is posted on the [project page](#).

### **Special Instructions for Submitting Comments with a Ballot**

Please note that comments submitted during the formal comment period and the ballots for the standards all use the same electronic form, and it is NOT necessary for ballot pool members to submit more than one set of comments. The drafting team requests that all stakeholders (ballot pool members as well as other stakeholders) submit all comments through the electronic comment form.

### **Next Steps**

The drafting team will consider all comments submitted during the formal comment period and ballots to determine whether to make additional revisions to the standards.

### **Background**

The purpose of Project 2010-07 is to ensure that all generator-owned Facilities are appropriately covered under NERC’s Reliability Standards. While many Generator Owners and Generator Operators operate Facilities, commonly known as generator interconnection Facilities, that are considered by some entities to be transmission, these are most often radial Facilities that are not part of the integrated grid. As such, they should not be subject to the same standards applicable to Transmission Owners and Transmission Operators who own and operate Transmission Elements and Facilities that are part of the integrated grid.

As part of the BES, generators do affect the overall reliability of the BES. But registering a Generator Owner or Generator Operator as a Transmission Owner or Transmission Operator, as has been the solution in some cases in the past, may decrease reliability by diverting the Generator Owner’s or Generator Operator’s resources from the operation of the equipment that actually produces electricity – the generation equipment itself.

The drafting team's goal is to ensure that an adequate level of reliability is maintained in the BES by clearly describing which standards need to be applied to generator interconnection Facilities that are not already applicable to Generator Owners or Generator Operators. This can be accomplished by properly applying FAC-001, FAC-003, and PRC-004 to Generator Owners as proposed in the redline standards posted for comment.

Before reviewing the standards, the drafting team encourages all stakeholders to read the [technical justification resource document](#) it has provided to describe its rationale and its work thus far.

Additional information is available on the [project page](#).

### **Standards Development Process**

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## Standards Announcement

Project 2010-07 Generator Requirements at the Transmission Interface  
Ballot Pool Forming October 5 – November 4, 2011

Formal Comment Period October 5 – November 18, 2011

Initial Ballot Windows Open November 9 – 18, 2011

### [Available Now](#)

The SDT has reviewed comments received during a 30-day formal comment period that took place earlier this year, from June 17-July 17, 2011, and thanks to all those who provided feedback during that comment period. The SDT has incorporated many of the suggested changes into its latest proposed standards, as explained in the posted Consideration of Comments.

This is the second formal comment period and initial ballot period for three standards included in Project 2010-07. Revised drafts of FAC-001-1 and two versions of FAC-003 – FAC-003-3 and FAC-003-X – along with minor modifications to PRC-004-2.1, have been posted for a formal comment period and initial ballot that will end on Friday, November 18, 2011. Note that FAC-003-X shows changes to the last approved version of the standard, while FAC-003-3 shows changes to the last version being developed by the Project 2007-07 drafting team to incorporate Requirements for Generator Owners in those standards.

PRC-004-2.1 is being posted for the first time with this posting, and is also being posted for a formal 45-day comment period with an initial ballot. Because the changes are very limited, the Standards Committee waived the initial formal comment period for this standard.

### **Instructions for Joining the Ballot Pool for Project 2010-07**

Registered Ballot Body members may join the ballot pool to be eligible to vote in the upcoming ballots at the following page: [Join Ballot Pool](#)

During the pre-ballot windows, members of the ballot pool may communicate with one another by using their “ballot pool list server.” (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) One ballot pool list server has been set up and can be used for communication on each of the standards being balloted for this project. The list server is: [bp-2010-07 FAC-001-1 in@nerc.com](mailto:bp-2010-07_FAC-001-1_in@nerc.com)



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# Standards Announcement

Project 2010-07 Generator Requirements at the Transmission Interface

## Initial Ballot Results

### [Now Available](#)

Initial ballots for each of the following standards and their associated implementation plans closed on November 18, 2011:

- FAC-001-1 – Facility Connection Requirements
- Two versions of FAC-003 – Transmission Vegetation Management (FAC-003-3 and FAC-003-X). *Note that FAC-003-X shows changes to FAC-003-1, while FAC-003-3 shows changes to FAC-003-2 developed by the Project 2007-07 drafting team. FAC-003-2 was adopted by the NERC Board on November 3, and a revised version of FAC-003-3 showing the Project 2010-07 drafting team's changes against the Board's version was posted.*
- PRC-004-2.1 – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

Voting statistics for each ballot are listed in the table below, and the [Ballot Results](#) Web page provides a link to the detailed results.

Standard	Quorum	Approval
FAC-001-1	88.22%	86.94%
FAC-003-3	85.08%	85.71%
FAC-003-X	84.82%	85.31%
PRC-004-2.1	84.29%	96.09%

### Next Steps

The drafting team will consider all comments received and determine whether to make additional changes to the standards. If the drafting team makes substantive changes to a standard, the standard will be posted for a parallel 30-day comment period and successive ballot. If the drafting team decides that no substantive changes are needed to a standard, a recirculation ballot will be conducted.

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User Name

Password

Log in

Register

- Ballot Pools
- Current Ballots
- Ballot Results
- Registered Ballot Body
- Proxy Voters

Home Page

Ballot Results	
<b>Ballot Name:</b>	Project 2010-07_FAC-001-1 Initial Ballot_in
<b>Ballot Period:</b>	11/9/2011 - 11/18/2011
<b>Ballot Type:</b>	Initial
<b>Total # Votes:</b>	337
<b>Total Ballot Pool:</b>	382
<b>Quorum:</b>	<b>88.22 % The Quorum has been reached</b>
<b>Weighted Segment Vote:</b>	86.94 %
<b>Ballot Results:</b>	<b>The standard will proceed to recirculation ballot.</b>

Summary of Ballot Results									
Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain # Votes	No Vote	
			# Votes	Fraction	# Votes	Fraction			
1 - Segment 1.		95	1	65	0.915	6	0.085	12	12
2 - Segment 2.		9	0.5	5	0.5	0	0	2	2
3 - Segment 3.		80	1	47	0.81	11	0.19	13	9
4 - Segment 4.		31	1	20	0.909	2	0.091	6	3
5 - Segment 5.		94	1	64	0.889	8	0.111	10	12
6 - Segment 6.		51	1	34	0.85	6	0.15	8	3
7 - Segment 7.		1	0	0	0	0	0	0	1
8 - Segment 8.		7	0.5	5	0.5	0	0	0	2
9 - Segment 9.		5	0.3	1	0.1	2	0.2	1	1
10 - Segment 10.		9	0.8	7	0.7	1	0.1	1	0
<b>Totals</b>		<b>382</b>	<b>7.1</b>	<b>248</b>	<b>6.173</b>	<b>36</b>	<b>0.927</b>	<b>53</b>	<b>45</b>

Individual Ballot Pool Results				
Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	<a href="#">View</a>
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Abstain	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	



1	Beaches Energy Services	Joseph S Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	<a href="#">View</a>
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	<a href="#">View</a>
1	East Kentucky Power Coop.	George S. Carruba	Abstain	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Abstain	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor	Affirmative	<a href="#">View</a>
1	Great River Energy	Gordon Pietsch	Affirmative	<a href="#">View</a>
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	<a href="#">View</a>
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Matthey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Brett A Koelsch	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	<a href="#">View</a>
1	Public Utility District No. 1 of Okanogan County	Dale Duncel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	

1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Affirmative	
1	Santee Cooper	Terry L Blackwell	Abstain	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	<a href="#">View</a>
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Abstain	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert Schaffeld	Negative	<a href="#">View</a>
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	<a href="#">View</a>
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Vermont Electric Power Company, Inc.	Kim Moulton		
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox		
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles Yeung		
3	AEP	Michael E Deloach	Affirmative	<a href="#">View</a>
3	Alabama Power Company	Richard J. Mandes	Negative	<a href="#">View</a>
3	Ameren Services	Mark Peters	Affirmative	
3	Anaheim Public Utilities Dept.	Kelly Nguyen	Abstain	
3	APS	Steven Norris	Abstain	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	<a href="#">View</a>
3	City of Alexandria	Michael Marcotte	Negative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Roseville	Susan E Gill-Zobitz	Abstain	
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	<a href="#">View</a>
3	Consumers Energy	Richard Blumenstock	Abstain	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	<a href="#">View</a>
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Negative	<a href="#">View</a>
3	Georgia Systems Operations Corporation	William N. Phinney	Abstain	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Sam Kokkinen	Affirmative	<a href="#">View</a>
3	Gulf Power Company	Paul C Caldwell	Negative	<a href="#">View</a>

3	Harney Electric Cooperative, Inc.	Shane Sweet	<a href="#">Abstain</a>	
3	Holland Board of Public Works	William Bush	<a href="#">Affirmative</a>	
3	Hydro One Networks, Inc.	David Kiguel	<a href="#">Affirmative</a>	
3	Imperial Irrigation District	Jesus S. Alcaraz	<a href="#">Affirmative</a>	
3	JEA	Garry Baker	<a href="#">Affirmative</a>	
3	Kansas City Power & Light Co.	Charles Locke	<a href="#">Affirmative</a>	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik	<a href="#">Abstain</a>	
3	Louisville Gas and Electric Co.	Charles A. Freibert	<a href="#">Affirmative</a>	
3	Manitoba Hydro	Greg C. Parent	<a href="#">Negative</a>	<a href="#">View</a>
3	Mississippi Power	Jeff Franklin	<a href="#">Negative</a>	<a href="#">View</a>
3	Municipal Electric Authority of Georgia	Steven M. Jackson		
3	Muscatine Power & Water	John S Bos	<a href="#">Affirmative</a>	<a href="#">View</a>
3	Nebraska Public Power District	Tony Eddleman	<a href="#">Affirmative</a>	
3	New York Power Authority	Marilyn Brown	<a href="#">Affirmative</a>	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	<a href="#">Affirmative</a>	
3	Northern Indiana Public Service Co.	William SeDoris	<a href="#">Negative</a>	<a href="#">View</a>
3	NRG Energy Power Marketing, Inc.	Rick Keetch		
3	Ocala Electric Utility	David Anderson	<a href="#">Affirmative</a>	
3	Orange and Rockland Utilities, Inc.	David Burke	<a href="#">Negative</a>	
3	Oregon Trail Electric Cooperative	ned ratterman	<a href="#">Affirmative</a>	
3	Orlando Utilities Commission	Ballard K Mutters	<a href="#">Affirmative</a>	
3	Owensboro Municipal Utilities	Thomas T Lyons	<a href="#">Affirmative</a>	
3	Pacific Gas and Electric Company	John H Hagen	<a href="#">Affirmative</a>	
3	PacifiCorp	Dan Zollner	<a href="#">Affirmative</a>	
3	Platte River Power Authority	Terry L Baker	<a href="#">Affirmative</a>	
3	PNM Resources	Michael Mertz		
3	Potomac Electric Power Co.	Robert Reuter	<a href="#">Abstain</a>	
3	Progress Energy Carolinas	Sam Waters	<a href="#">Affirmative</a>	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	<a href="#">Negative</a>	<a href="#">View</a>
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	<a href="#">Affirmative</a>	
3	Sacramento Municipal Utility District	James Leigh-Kendall	<a href="#">Affirmative</a>	
3	Salt River Project	John T. Underhill	<a href="#">Affirmative</a>	
3	Santee Cooper	James M Poston	<a href="#">Abstain</a>	
3	Seattle City Light	Dana Wheelock	<a href="#">Affirmative</a>	<a href="#">View</a>
3	Seminole Electric Cooperative, Inc.	James R Frauen	<a href="#">Affirmative</a>	
3	Snohomish County PUD No. 1	Mark Oens		
3	South Carolina Electric & Gas Co.	Hubert C Young	<a href="#">Affirmative</a>	
3	Tacoma Public Utilities	Travis Metcalfe	<a href="#">Affirmative</a>	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	<a href="#">Negative</a>	
3	Tri-State G & T Association, Inc.	Janelle Marriott	<a href="#">Affirmative</a>	
3	Westar Energy	Bo Jones	<a href="#">Affirmative</a>	
3	Wisconsin Electric Power Marketing	James R Keller	<a href="#">Abstain</a>	
3	Xcel Energy, Inc.	Michael Ibold	<a href="#">Affirmative</a>	
4	Alabama Municipal Electric Authority	Raymond Phillips	<a href="#">Affirmative</a>	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	<a href="#">Affirmative</a>	
4	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	City of Clewiston	Kevin McCarthy	<a href="#">Affirmative</a>	
4	City of Redding	Nicholas Zettel	<a href="#">Affirmative</a>	
4	City Utilities of Springfield, Missouri	John Allen	<a href="#">Negative</a>	<a href="#">View</a>
4	Consumers Energy	David Frank Ronk	<a href="#">Abstain</a>	
4	Cowlitz County PUD	Rick Syring	<a href="#">Affirmative</a>	
4	Detroit Edison Company	Daniel Herring	<a href="#">Affirmative</a>	
4	Flathead Electric Cooperative	Russ Schneider	<a href="#">Negative</a>	
4	Florida Municipal Power Agency	Frank Gaffney	<a href="#">Affirmative</a>	
4	Fort Pierce Utilities Authority	Thomas Richards		
4	Georgia System Operations Corporation	Guy Andrews	<a href="#">Abstain</a>	
4	Imperial Irrigation District	Diana U Torres	<a href="#">Affirmative</a>	<a href="#">View</a>
4	Indiana Municipal Power Agency	Jack Alvey	<a href="#">Affirmative</a>	
4	Integrus Energy Group, Inc.	Christopher Plante	<a href="#">Abstain</a>	
4	Madison Gas and Electric Co.	Joseph DePoorter	<a href="#">Abstain</a>	
4	Modesto Irrigation District	Spencer Tacke	<a href="#">Affirmative</a>	
4	North Carolina Electric Membership Corp.	Bob Beadle	<a href="#">Affirmative</a>	
4	Northern California Power Agency	Tracy R Bibb	<a href="#">Affirmative</a>	

4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	<a href="#">View</a>
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhane	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko		
5	AES Corporation	Leo Bernier	Negative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Wind Energy Association	Natalie McIntire	Affirmative	<a href="#">View</a>
5	Arizona Public Service Co.	Edward Cambridge		
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Bayer	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	City and County of San Francisco	Daniel Mason	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	
5	City of Tallahassee	Brian Horton	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Cogentrix Energy, Inc.	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	<a href="#">View</a>
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Affirmative	<a href="#">View</a>
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	CPS Energy	Robert Stevens	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	<a href="#">View</a>
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	East Kentucky Power Coop.	Stephen Ricker	Abstain	
5	Electric Power Supply Association	John R Cashin	Affirmative	<a href="#">View</a>
5	Energy Northwest - Columbia Generating Station	James Saucedo	Affirmative	
5	Entegra Power Group, LLC	Kenneth B Parker	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Green Country Energy	Greg Froehling	Affirmative	
5	Imperial Irrigation District	Marcela Y Caballero	Affirmative	
5	Indeck Energy Services, Inc.	Rex A Roehl	Affirmative	
5	Infigen Energy US	Pamela C Zdenek	Affirmative	<a href="#">View</a>
5	Invenergy LLC	Alan Beckham	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Tom Foreman	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	

5	Manitoba Hydro	S N Fernando	Negative	<a href="#">View</a>
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego		
5	MidAmerican Energy Co.	Christopher Schneider		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern California Power Agency	Hari Modi	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	
5	Occidental Chemical	Michelle R DAntuono	Negative	
5	Oklahoma Gas and Electric Co.	Kim Morphis		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	Colin Anderson	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Fossil LLC	Mikhail Falkovich	Negative	<a href="#">View</a>
5	Public Utility District No. 1 of Lewis County	Steven Grega	Abstain	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	RES Americas Inc	Ravi Bantu	Affirmative	<a href="#">View</a>
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Siemens PTI	Edwin Cano	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	<a href="#">View</a>
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M Helyer	Affirmative	
5	Tennessee Valley Authority	David Thompson	Negative	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles		
6	ACES Power Marketing	Jason L Marshall	Affirmative	<a href="#">View</a>
6	AEP Marketing	Edward P. Cox	Affirmative	<a href="#">View</a>
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	RANDY A YOUNG	Abstain	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirschak	Affirmative	
6	Colorado Springs Utilities	Lisa C Rosintoski	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	<a href="#">View</a>
6	Constellation Energy Commodities Group	Brenda Powell	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager		
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Luminant Energy	Brad Jones	Affirmative	

6	Manitoba Hydro	Daniel Prowse	Negative	View
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Orlando Utilities Commission	Claston Augustus Sunanon	Affirmative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	View
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	View
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Abstain	
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	View
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Edward C Stein	Affirmative	
8		James A Maenner	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini		
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Volkman Consulting, Inc.	Terry Volkman	Affirmative	
9	California Energy Commission	William M Chamberlain		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Negative	View
9	New York State Department of Public Service	Thomas Dvorsky	Negative	View
9	Public Utilities Commission of Ohio	Klaus Lambeck	Abstain	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Abstain	View
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	View
10	Southwest Power Pool RE	Emily Pennel	Affirmative	View
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	View
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	View

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Ballot Results	
<b>Ballot Name:</b>	Project 2010-07 FAC-003-X_in
<b>Ballot Period:</b>	11/9/2011 - 11/18/2011
<b>Ballot Type:</b>	Initial
<b>Total # Votes:</b>	324
<b>Total Ballot Pool:</b>	382
<b>Quorum:</b>	<b>84.82 % The Quorum has been reached</b>
<b>Weighted Segment Vote:</b>	85.31 %
<b>Ballot Results:</b>	<b>The standard will proceed to recirculation ballot.</b>

Summary of Ballot Results									
Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain	No Vote	
			# Votes	Fraction	# Votes	Fraction	# Votes	No Vote	
1 - Segment 1.		95	1	57	0.891	7	0.109	16	15
2 - Segment 2.		9	0.5	4	0.4	1	0.1	2	2
3 - Segment 3.		80	1	42	0.792	11	0.208	17	10
4 - Segment 4.		31	1	15	0.882	2	0.118	8	6
5 - Segment 5.		94	1	56	0.903	6	0.097	16	16
6 - Segment 6.		51	1	30	0.833	6	0.167	11	4
7 - Segment 7.		1	0	0	0	0	0	0	1
8 - Segment 8.		7	0.4	4	0.4	0	0	1	2
9 - Segment 9.		5	0.2	2	0.2	0	0	1	2
10 - Segment 10.		9	0.7	5	0.5	2	0.2	2	0
<b>Totals</b>		<b>382</b>	<b>6.8</b>	<b>215</b>	<b>5.801</b>	<b>35</b>	<b>0.999</b>	<b>74</b>	<b>58</b>

Individual Ballot Pool Results				
Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	<a href="#">View</a>
1	American Electric Power	Paul B. Johnson	Affirmative	<a href="#">View</a>
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Abstain	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith		
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	



1	Beaches Energy Services	Joseph S Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	<a href="#">View</a>
1	East Kentucky Power Coop.	George S. Carruba	Abstain	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	<a href="#">View</a>
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Negative	<a href="#">View</a>
1	Georgia Transmission Corporation	Harold Taylor		
1	Great River Energy	Gordon Pietsch	Affirmative	<a href="#">View</a>
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	<a href="#">View</a>
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Matthey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	<a href="#">View</a>
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Brett A Koelsch	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	<a href="#">View</a>
1	Public Utility District No. 1 of Okanogan County	Dale Duncel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	

1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley		
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	Santee Cooper	Terry L Blackwell	Abstain	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	<a href="#">View</a>
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Sierra Pacific Power Co.	Rich Salgo	Abstain	
1	Snohomish County PUD No. 1	Long T Duong	Abstain	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert Schaffeld	Negative	<a href="#">View</a>
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Vermont Electric Power Company, Inc.	Kim Moulton		
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox		
2	New Brunswick System Operator	Alden Briggs	Negative	<a href="#">View</a>
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles Yeung		
3	AEP	Michael E Deloach	Affirmative	<a href="#">View</a>
3	Alabama Power Company	Richard J. Mandes	Negative	<a href="#">View</a>
3	Ameren Services	Mark Peters	Negative	
3	Anaheim Public Utilities Dept.	Kelly Nguyen	Abstain	
3	APS	Steven Norris	Abstain	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	<a href="#">View</a>
3	City of Alexandria	Michael Marcotte	Negative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Roseville	Susan E Gill-Zobitz	Abstain	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy	Richard Blumenstock	Abstain	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	<a href="#">View</a>
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Energy Delivery	Stephan Kern	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Negative	<a href="#">View</a>
3	Georgia Systems Operations Corporation	William N. Phinney	Abstain	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Sam Kokkinen	Affirmative	<a href="#">View</a>
3	Gulf Power Company	Paul C Caldwell	Negative	<a href="#">View</a>

3	Harney Electric Cooperative, Inc.	Shane Sweet	<a href="#">Abstain</a>	
3	Holland Board of Public Works	William Bush	<a href="#">Affirmative</a>	
3	Hydro One Networks, Inc.	David Kiguel	<a href="#">Affirmative</a>	
3	Imperial Irrigation District	Jesus S. Alcaraz	<a href="#">Affirmative</a>	
3	JEA	Garry Baker	<a href="#">Affirmative</a>	
3	Kansas City Power & Light Co.	Charles Locke	<a href="#">Affirmative</a>	
3	Kissimmee Utility Authority	Gregory D Woessner	<a href="#">Negative</a>	
3	Lincoln Electric System	Jason Fortik	<a href="#">Abstain</a>	
3	Louisville Gas and Electric Co.	Charles A. Freibert	<a href="#">Affirmative</a>	
3	Manitoba Hydro	Greg C. Parent	<a href="#">Negative</a>	<a href="#">View</a>
3	Mississippi Power	Jeff Franklin	<a href="#">Negative</a>	<a href="#">View</a>
3	Municipal Electric Authority of Georgia	Steven M. Jackson		
3	Muscatine Power & Water	John S Bos	<a href="#">Affirmative</a>	
3	Nebraska Public Power District	Tony Eddleman	<a href="#">Affirmative</a>	
3	New York Power Authority	Marilyn Brown	<a href="#">Affirmative</a>	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	<a href="#">Affirmative</a>	
3	Northern Indiana Public Service Co.	William SeDoris	<a href="#">Negative</a>	<a href="#">View</a>
3	NRG Energy Power Marketing, Inc.	Rick Keetch		
3	Ocala Electric Utility	David Anderson	<a href="#">Negative</a>	
3	Orange and Rockland Utilities, Inc.	David Burke	<a href="#">Abstain</a>	
3	Oregon Trail Electric Cooperative	ned ratterman	<a href="#">Affirmative</a>	
3	Orlando Utilities Commission	Ballard K Mutters	<a href="#">Affirmative</a>	
3	Owensboro Municipal Utilities	Thomas T Lyons	<a href="#">Affirmative</a>	
3	Pacific Gas and Electric Company	John H Hagen	<a href="#">Affirmative</a>	
3	PacifiCorp	Dan Zollner	<a href="#">Affirmative</a>	
3	Platte River Power Authority	Terry L Baker	<a href="#">Affirmative</a>	
3	PNM Resources	Michael Mertz		
3	Potomac Electric Power Co.	Robert Reuter	<a href="#">Abstain</a>	
3	Progress Energy Carolinas	Sam Waters	<a href="#">Affirmative</a>	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	<a href="#">Negative</a>	<a href="#">View</a>
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	<a href="#">Affirmative</a>	
3	Sacramento Municipal Utility District	James Leigh-Kendall		
3	Salt River Project	John T. Underhill	<a href="#">Affirmative</a>	
3	Santee Cooper	James M Poston	<a href="#">Abstain</a>	
3	Seattle City Light	Dana Wheelock	<a href="#">Affirmative</a>	<a href="#">View</a>
3	Seminole Electric Cooperative, Inc.	James R Frauen	<a href="#">Affirmative</a>	
3	Snohomish County PUD No. 1	Mark Oens		
3	South Carolina Electric & Gas Co.	Hubert C Young	<a href="#">Affirmative</a>	
3	Tacoma Public Utilities	Travis Metcalfe	<a href="#">Affirmative</a>	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	<a href="#">Abstain</a>	
3	Tri-State G & T Association, Inc.	Janelle Marriott	<a href="#">Affirmative</a>	
3	Westar Energy	Bo Jones	<a href="#">Affirmative</a>	
3	Wisconsin Electric Power Marketing	James R Keller	<a href="#">Abstain</a>	
3	Xcel Energy, Inc.	Michael Ibold	<a href="#">Affirmative</a>	
4	Alabama Municipal Electric Authority	Raymond Phillips	<a href="#">Affirmative</a>	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	<a href="#">Affirmative</a>	
4	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	City of Clewiston	Kevin McCarthy	<a href="#">Affirmative</a>	
4	City of Redding	Nicholas Zettel	<a href="#">Affirmative</a>	
4	City Utilities of Springfield, Missouri	John Allen	<a href="#">Negative</a>	<a href="#">View</a>
4	Consumers Energy	David Frank Ronk	<a href="#">Abstain</a>	
4	Cowlitz County PUD	Rick Syring	<a href="#">Affirmative</a>	
4	Detroit Edison Company	Daniel Herring	<a href="#">Affirmative</a>	
4	Flathead Electric Cooperative	Russ Schneider	<a href="#">Negative</a>	
4	Florida Municipal Power Agency	Frank Gaffney	<a href="#">Affirmative</a>	
4	Fort Pierce Utilities Authority	Thomas Richards		
4	Georgia System Operations Corporation	Guy Andrews	<a href="#">Abstain</a>	
4	Imperial Irrigation District	Diana U Torres	<a href="#">Affirmative</a>	<a href="#">View</a>
4	Indiana Municipal Power Agency	Jack Alvey		
4	Integrays Energy Group, Inc.	Christopher Plante	<a href="#">Abstain</a>	
4	Madison Gas and Electric Co.	Joseph DePoorter	<a href="#">Abstain</a>	
4	Modesto Irrigation District	Spencer Tacke		
4	North Carolina Electric Membership Corp.	Bob Beadle	<a href="#">Affirmative</a>	
4	Northern California Power Agency	Tracy R Bibb	<a href="#">Abstain</a>	

4	Ohio Edison Company	Douglas Hohlbaugh	<a href="#">Abstain</a>	
4	Old Dominion Electric Coop.	Mark Ringhausen	<a href="#">Affirmative</a>	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	<a href="#">Affirmative</a>	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	<a href="#">Abstain</a>	
4	Sacramento Municipal Utility District	Mike Ramirez		
4	Seattle City Light	Hao Li	<a href="#">Affirmative</a>	<a href="#">View</a>
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	<a href="#">Affirmative</a>	
4	South Mississippi Electric Power Association	Steven McElhaney	<a href="#">Affirmative</a>	
4	Tacoma Public Utilities	Keith Morisette	<a href="#">Affirmative</a>	
4	Wisconsin Energy Corp.	Anthony Jankowski	<a href="#">Abstain</a>	
5	AEP Service Corp.	Brock Ondayko		
5	AES Corporation	Leo Bernier	<a href="#">Affirmative</a>	
5	Amerenue	Sam Dwyer	<a href="#">Negative</a>	
5	American Wind Energy Association	Natalie McIntire	<a href="#">Affirmative</a>	<a href="#">View</a>
5	Arizona Public Service Co.	Edward Cambridge		
5	Avista Corp.	Edward F. Groce	<a href="#">Affirmative</a>	
5	BC Hydro and Power Authority	Clement Ma	<a href="#">Abstain</a>	
5	Black Hills Corp	George Tatar	<a href="#">Affirmative</a>	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	<a href="#">Affirmative</a>	
5	BP Wind Energy North America Inc	Carla Bayer	<a href="#">Affirmative</a>	
5	BrightSource Energy, Inc.	Chifong Thomas	<a href="#">Abstain</a>	
5	City and County of San Francisco	Daniel Mason	<a href="#">Abstain</a>	
5	City of Austin dba Austin Energy	Jeanie Doty	<a href="#">Affirmative</a>	
5	City of Redding	Paul Cummings	<a href="#">Affirmative</a>	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	<a href="#">Affirmative</a>	
5	City of Tallahassee	Brian Horton	<a href="#">Affirmative</a>	
5	City Water, Light & Power of Springfield	Steve Rose	<a href="#">Affirmative</a>	
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy, Inc.	Mike D Hirst	<a href="#">Affirmative</a>	
5	Colorado Springs Utilities	Jennifer Eckels	<a href="#">Affirmative</a>	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	<a href="#">Abstain</a>	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	<a href="#">Affirmative</a>	<a href="#">View</a>
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex	<a href="#">Affirmative</a>	
5	CPS Energy	Robert Stevens	<a href="#">Affirmative</a>	
5	Detroit Edison Company	Christy Wicke	<a href="#">Affirmative</a>	
5	Dominion Resources, Inc.	Mike Garton	<a href="#">Affirmative</a>	
5	Duke Energy	Dale Q Goodwine	<a href="#">Affirmative</a>	<a href="#">View</a>
5	Dynegy Inc.	Dan Roethemeyer	<a href="#">Affirmative</a>	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	<a href="#">Abstain</a>	
5	East Kentucky Power Coop.	Stephen Ricker	<a href="#">Abstain</a>	
5	Electric Power Supply Association	John R Cashin	<a href="#">Affirmative</a>	
5	Energy Northwest - Columbia Generating Station	James Saucedo	<a href="#">Abstain</a>	
5	Entegra Power Group, LLC	Kenneth B Parker	<a href="#">Abstain</a>	
5	Exelon Nuclear	Michael Korchynsky	<a href="#">Affirmative</a>	
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	<a href="#">Abstain</a>	
5	Florida Municipal Power Agency	David Schumann	<a href="#">Affirmative</a>	
5	Great River Energy	Preston L Walsh	<a href="#">Affirmative</a>	
5	Green Country Energy	Greg Froehling	<a href="#">Affirmative</a>	
5	Imperial Irrigation District	Marcela Y Caballero	<a href="#">Affirmative</a>	
5	Indeck Energy Services, Inc.	Rex A Roehl	<a href="#">Affirmative</a>	
5	Infigen Energy US	Pamela C Zdenek	<a href="#">Affirmative</a>	<a href="#">View</a>
5	Invenergy LLC	Alan Beckham	<a href="#">Affirmative</a>	
5	JEA	John J Babik	<a href="#">Affirmative</a>	
5	Kissimmee Utility Authority	Mike Blough	<a href="#">Affirmative</a>	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	<a href="#">Affirmative</a>	
5	Lincoln Electric System	Dennis Florom	<a href="#">Abstain</a>	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Tom Foreman	<a href="#">Affirmative</a>	
5	Luminant Generation Company LLC	Mike Laney	<a href="#">Affirmative</a>	

5	Manitoba Hydro	S N Fernando	Negative	<a href="#">View</a>
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego		
5	MidAmerican Energy Co.	Christopher Schneider		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern California Power Agency	Hari Modi	Abstain	
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oklahoma Gas and Electric Co.	Kim Morphis		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	Colin Anderson	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Gary L Tingley		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Fossil LLC	Mikhail Falkovich	Negative	<a href="#">View</a>
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	RES Americas Inc	Ravi Bantu	Affirmative	<a href="#">View</a>
5	Sacramento Municipal Utility District	Bethany Hunter		
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Siemens PTI	Edwin Cano	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	<a href="#">View</a>
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M Helyer	Affirmative	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Negative	
5	Xcel Energy, Inc.	Liam Noailles		
6	ACES Power Marketing	Jason L Marshall	Affirmative	<a href="#">View</a>
6	AEP Marketing	Edward P. Cox	Affirmative	<a href="#">View</a>
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	RANDY A YOUNG	Abstain	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirschak	Negative	
6	Colorado Springs Utilities	Lisa C Rosintoski	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Abstain	
6	Constellation Energy Commodities Group	Brenda Powell	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager		
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Luminant Energy	Brad Jones	Affirmative	

6	Manitoba Hydro	Daniel Prowse	Negative	<a href="#">View</a>
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Orlando Utilities Commission	Claston Augustus Sunanon	Affirmative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	<a href="#">View</a>
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	<a href="#">View</a>
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby		
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Abstain	
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	<a href="#">View</a>
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner	Abstain	
8		Edward C Stein	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini		
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Volkman Consulting, Inc.	Terry Volkman	Affirmative	
9	California Energy Commission	William M Chamberlain		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Affirmative	
9	New York State Department of Public Service	Thomas Dvorsky	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck	Abstain	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	James D Burley	Abstain	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Negative	<a href="#">View</a>
10	Southwest Power Pool RE	Emily Pennel	Affirmative	<a href="#">View</a>
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	<a href="#">View</a>
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	<a href="#">View</a>

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Ballot Results	
<b>Ballot Name:</b>	Project 2010-07 FAC-003-3 Initial Ballot_in
<b>Ballot Period:</b>	11/9/2011 - 11/18/2011
<b>Ballot Type:</b>	Initial
<b>Total # Votes:</b>	325
<b>Total Ballot Pool:</b>	382
<b>Quorum:</b>	<b>85.08 % The Quorum has been reached</b>
<b>Weighted Segment Vote:</b>	85.71 %
<b>Ballot Results:</b>	<b>The standard will proceed to recirculation ballot.</b>

Summary of Ballot Results									
Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain	No Vote	
			# Votes	Fraction	# Votes	Fraction	# Votes	No Vote	
1 - Segment 1.	95	1	58	0.866	9	0.134	14	14	
2 - Segment 2.	9	0.5	5	0.5	0	0	2	2	
3 - Segment 3.	80	1	44	0.815	10	0.185	16	10	
4 - Segment 4.	31	1	16	0.889	2	0.111	7	6	
5 - Segment 5.	94	1	58	0.906	6	0.094	14	16	
6 - Segment 6.	51	1	31	0.838	6	0.162	10	4	
7 - Segment 7.	1	0	0	0	0	0	0	1	
8 - Segment 8.	7	0.4	4	0.4	0	0	1	2	
9 - Segment 9.	5	0.2	2	0.2	0	0	1	2	
10 - Segment 10.	9	0.8	5	0.5	3	0.3	1	0	
<b>Totals</b>	<b>382</b>	<b>6.9</b>	<b>223</b>	<b>5.914</b>	<b>36</b>	<b>0.986</b>	<b>66</b>	<b>57</b>	

Individual Ballot Pool Results				
Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	<a href="#">View</a>
1	American Electric Power	Paul B. Johnson	Affirmative	<a href="#">View</a>
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Abstain	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith		
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	



1	Beaches Energy Services	Joseph S Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	<a href="#">View</a>
1	East Kentucky Power Coop.	George S. Carruba	Abstain	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	<a href="#">View</a>
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Negative	<a href="#">View</a>
1	Georgia Transmission Corporation	Harold Taylor		
1	Great River Energy	Gordon Pietsch	Affirmative	<a href="#">View</a>
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Negative	<a href="#">View</a>
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Negative	<a href="#">View</a>
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	<a href="#">View</a>
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Matthey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	<a href="#">View</a>
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Brett A Koelsch	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	
1	Public Utility District No. 1 of Okanogan County	Dale Duncel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	

1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley		
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	Santee Cooper	Terry L Blackwell	Abstain	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	<a href="#">View</a>
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Sierra Pacific Power Co.	Rich Salgo	Abstain	
1	Snohomish County PUD No. 1	Long T Duong	Abstain	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert Schaffeld	Negative	<a href="#">View</a>
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	<a href="#">View</a>
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Vermont Electric Power Company, Inc.	Kim Moulton		
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox		
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles Yeung		
3	AEP	Michael E Deloach	Affirmative	<a href="#">View</a>
3	Alabama Power Company	Richard J. Mandes	Negative	<a href="#">View</a>
3	Ameren Services	Mark Peters	Negative	
3	Anaheim Public Utilities Dept.	Kelly Nguyen	Abstain	
3	APS	Steven Norris	Abstain	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	<a href="#">View</a>
3	City of Alexandria	Michael Marcotte	Negative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Roseville	Susan E Gill-Zobitz	Abstain	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy	Richard Blumenstock	Abstain	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	<a href="#">View</a>
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Negative	<a href="#">View</a>
3	Georgia Systems Operations Corporation	William N. Phinney	Abstain	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Sam Kokkinen	Affirmative	<a href="#">View</a>
3	Gulf Power Company	Paul C Caldwell	Negative	<a href="#">View</a>

3	Harney Electric Cooperative, Inc.	Shane Sweet	<a href="#">Abstain</a>	
3	Holland Board of Public Works	William Bush	<a href="#">Affirmative</a>	
3	Hydro One Networks, Inc.	David Kiguel	<a href="#">Affirmative</a>	
3	Imperial Irrigation District	Jesus S. Alcaraz	<a href="#">Affirmative</a>	
3	JEA	Garry Baker	<a href="#">Affirmative</a>	
3	Kansas City Power & Light Co.	Charles Locke	<a href="#">Affirmative</a>	
3	Kissimmee Utility Authority	Gregory D Woessner	<a href="#">Negative</a>	
3	Lincoln Electric System	Jason Fortik	<a href="#">Abstain</a>	
3	Louisville Gas and Electric Co.	Charles A. Freibert	<a href="#">Affirmative</a>	
3	Manitoba Hydro	Greg C. Parent	<a href="#">Negative</a>	<a href="#">View</a>
3	Mississippi Power	Jeff Franklin	<a href="#">Negative</a>	<a href="#">View</a>
3	Municipal Electric Authority of Georgia	Steven M. Jackson		
3	Muscatine Power & Water	John S Bos	<a href="#">Affirmative</a>	<a href="#">View</a>
3	Nebraska Public Power District	Tony Eddleman	<a href="#">Affirmative</a>	
3	New York Power Authority	Marilyn Brown	<a href="#">Affirmative</a>	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	<a href="#">Affirmative</a>	
3	Northern Indiana Public Service Co.	William SeDoris	<a href="#">Negative</a>	<a href="#">View</a>
3	NRG Energy Power Marketing, Inc.	Rick Keetch		
3	Ocala Electric Utility	David Anderson	<a href="#">Affirmative</a>	
3	Orange and Rockland Utilities, Inc.	David Burke	<a href="#">Abstain</a>	
3	Oregon Trail Electric Cooperative	ned ratterman	<a href="#">Affirmative</a>	
3	Orlando Utilities Commission	Ballard K Mutters	<a href="#">Affirmative</a>	
3	Owensboro Municipal Utilities	Thomas T Lyons	<a href="#">Affirmative</a>	
3	Pacific Gas and Electric Company	John H Hagen	<a href="#">Affirmative</a>	
3	PacifiCorp	Dan Zollner	<a href="#">Affirmative</a>	
3	Platte River Power Authority	Terry L Baker	<a href="#">Affirmative</a>	
3	PNM Resources	Michael Mertz		
3	Potomac Electric Power Co.	Robert Reuter	<a href="#">Abstain</a>	
3	Progress Energy Carolinas	Sam Waters	<a href="#">Affirmative</a>	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	<a href="#">Negative</a>	
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	<a href="#">Affirmative</a>	
3	Sacramento Municipal Utility District	James Leigh-Kendall		
3	Salt River Project	John T. Underhill	<a href="#">Affirmative</a>	
3	Santee Cooper	James M Poston	<a href="#">Abstain</a>	
3	Seattle City Light	Dana Wheelock	<a href="#">Affirmative</a>	<a href="#">View</a>
3	Seminole Electric Cooperative, Inc.	James R Frauen	<a href="#">Affirmative</a>	
3	Snohomish County PUD No. 1	Mark Oens		
3	South Carolina Electric & Gas Co.	Hubert C Young	<a href="#">Affirmative</a>	
3	Tacoma Public Utilities	Travis Metcalfe	<a href="#">Affirmative</a>	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	<a href="#">Abstain</a>	
3	Tri-State G & T Association, Inc.	Janelle Marriott	<a href="#">Affirmative</a>	
3	Westar Energy	Bo Jones	<a href="#">Affirmative</a>	
3	Wisconsin Electric Power Marketing	James R Keller	<a href="#">Abstain</a>	
3	Xcel Energy, Inc.	Michael Ibold	<a href="#">Affirmative</a>	
4	Alabama Municipal Electric Authority	Raymond Phillips	<a href="#">Affirmative</a>	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	<a href="#">Affirmative</a>	
4	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	City of Clewiston	Kevin McCarthy	<a href="#">Affirmative</a>	
4	City of Redding	Nicholas Zettel	<a href="#">Affirmative</a>	
4	City Utilities of Springfield, Missouri	John Allen	<a href="#">Negative</a>	<a href="#">View</a>
4	Consumers Energy	David Frank Ronk	<a href="#">Abstain</a>	
4	Cowlitz County PUD	Rick Syring	<a href="#">Affirmative</a>	
4	Detroit Edison Company	Daniel Herring	<a href="#">Affirmative</a>	
4	Flathead Electric Cooperative	Russ Schneider	<a href="#">Negative</a>	
4	Florida Municipal Power Agency	Frank Gaffney	<a href="#">Affirmative</a>	
4	Fort Pierce Utilities Authority	Thomas Richards		
4	Georgia System Operations Corporation	Guy Andrews	<a href="#">Abstain</a>	
4	Imperial Irrigation District	Diana U Torres	<a href="#">Affirmative</a>	<a href="#">View</a>
4	Indiana Municipal Power Agency	Jack Alvey		
4	Integrus Energy Group, Inc.	Christopher Plante	<a href="#">Abstain</a>	
4	Madison Gas and Electric Co.	Joseph DePoorter	<a href="#">Abstain</a>	
4	Modesto Irrigation District	Spencer Tacke		
4	North Carolina Electric Membership Corp.	Bob Beadle	<a href="#">Affirmative</a>	
4	Northern California Power Agency	Tracy R Bibb	<a href="#">Abstain</a>	

4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez		
4	Seattle City Light	Hao Li	Affirmative	<a href="#">View</a>
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhane	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko		
5	AES Corporation	Leo Bernier	Affirmative	
5	Amerenue	Sam Dwyer	Negative	
5	American Wind Energy Association	Natalie McIntire	Affirmative	<a href="#">View</a>
5	Arizona Public Service Co.	Edward Cambridge		
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Bayer	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas	Abstain	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	
5	City of Tallahassee	Brian Horton	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy, Inc.	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Affirmative	<a href="#">View</a>
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	CPS Energy	Robert Stevens	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	<a href="#">View</a>
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	East Kentucky Power Coop.	Stephen Ricker	Abstain	
5	Electric Power Supply Association	John R Cashin	Affirmative	
5	Energy Northwest - Columbia Generating Station	James Saucedo	Affirmative	
5	Entegra Power Group, LLC	Kenneth B Parker	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Green Country Energy	Greg Froehling	Affirmative	
5	Imperial Irrigation District	Marcela Y Caballero	Affirmative	
5	Indeck Energy Services, Inc.	Rex A Roehl	Affirmative	
5	Infigen Energy US	Pamela C Zdenek	Affirmative	<a href="#">View</a>
5	Invenergy LLC	Alan Beckham	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Tom Foreman	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	

5	Manitoba Hydro	S N Fernando	Negative	<a href="#">View</a>
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego		
5	MidAmerican Energy Co.	Christopher Schneider		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern California Power Agency	Hari Modi	Abstain	
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oklahoma Gas and Electric Co.	Kim Morphis		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	Colin Anderson	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Gary L Tingley		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Fossil LLC	Mikhail Falkovich	Negative	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	RES Americas Inc	Ravi Bantu	Affirmative	<a href="#">View</a>
5	Sacramento Municipal Utility District	Bethany Hunter		
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Siemens PTI	Edwin Cano	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	<a href="#">View</a>
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M Helyer	Affirmative	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Negative	<a href="#">View</a>
5	Xcel Energy, Inc.	Liam Noailles		
6	ACES Power Marketing	Jason L Marshall	Affirmative	<a href="#">View</a>
6	AEP Marketing	Edward P. Cox	Affirmative	<a href="#">View</a>
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	RANDY A YOUNG	Abstain	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirschak	Negative	
6	Colorado Springs Utilities	Lisa C Rosintoski	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Abstain	
6	Constellation Energy Commodities Group	Brenda Powell	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager		
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Luminant Energy	Brad Jones	Affirmative	

6	Manitoba Hydro	Daniel Prowse	Negative	<a href="#">View</a>
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Orlando Utilities Commission	Claston Augustus Sunanon	Affirmative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	<a href="#">View</a>
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby		
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Abstain	
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	<a href="#">View</a>
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner	Abstain	
8		Edward C Stein	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini		
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Volkman Consulting, Inc.	Terry Volkman	Affirmative	
9	California Energy Commission	William M Chamberlain		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Affirmative	
9	New York State Department of Public Service	Thomas Dvorsky	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck	Abstain	
10	Florida Reliability Coordinating Council	Linda Campbell	Negative	<a href="#">View</a>
10	Midwest Reliability Organization	James D Burley	Abstain	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Negative	<a href="#">View</a>
10	Southwest Power Pool RE	Emily Pennel	Affirmative	<a href="#">View</a>
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	<a href="#">View</a>
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	<a href="#">View</a>

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 Washington Office: 1120 G Street, N.W. : Suite 990 : Washington, DC 20005-3801

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Ballot Results	
<b>Ballot Name:</b>	Project 2010-07 PRC-004-2.1 Initial Ballot_in
<b>Ballot Period:</b>	11/9/2011 - 11/18/2011
<b>Ballot Type:</b>	Initial
<b>Total # Votes:</b>	322
<b>Total Ballot Pool:</b>	382
<b>Quorum:</b>	<b>84.29 % The Quorum has been reached</b>
<b>Weighted Segment Vote:</b>	96.09 %
<b>Ballot Results:</b>	<b>The standard will proceed to recirculation ballot.</b>

Summary of Ballot Results									
Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain # Votes	No Vote	
			# Votes	Fraction	# Votes	Fraction			
1 - Segment 1.		95	1	61	0.953	3	0.047	15	16
2 - Segment 2.		9	0.5	5	0.5	0	0	2	2
3 - Segment 3.		80	1	52	0.945	3	0.055	14	11
4 - Segment 4.		31	1	20	0.952	1	0.048	5	5
5 - Segment 5.		94	1	63	0.955	3	0.045	11	17
6 - Segment 6.		51	1	35	0.921	3	0.079	9	4
7 - Segment 7.		1	0	0	0	0	0	0	1
8 - Segment 8.		7	0.5	5	0.5	0	0	0	2
9 - Segment 9.		5	0.2	2	0.2	0	0	1	2
10 - Segment 10.		9	0.8	8	0.8	0	0	1	0
<b>Totals</b>		<b>382</b>	<b>7</b>	<b>251</b>	<b>6.726</b>	<b>13</b>	<b>0.274</b>	<b>58</b>	<b>60</b>

Individual Ballot Pool Results				
Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	<a href="#">Affirmative</a>	<a href="#">View</a>
1	American Electric Power	Paul B. Johnson	<a href="#">Affirmative</a>	<a href="#">View</a>
1	American Transmission Company, LLC	Andrew Z Pusztai	<a href="#">Affirmative</a>	
1	Arizona Public Service Co.	Robert Smith	<a href="#">Abstain</a>	
1	Associated Electric Cooperative, Inc.	John Bussman	<a href="#">Affirmative</a>	
1	Avista Corp.	Scott J Kinney	<a href="#">Affirmative</a>	
1	Balancing Authority of Northern California	Kevin Smith		
1	BC Hydro and Power Authority	Patricia Robertson	<a href="#">Abstain</a>	



1	Beaches Energy Services	Joseph S Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	<a href="#">View</a>
1	East Kentucky Power Coop.	George S. Carruba	Abstain	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Abstain	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Abstain	
1	Georgia Transmission Corporation	Harold Taylor		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	<a href="#">View</a>
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Matthey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	<a href="#">View</a>
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Brett A Koelsch	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Duncel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	<a href="#">View</a>

1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley		
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	Santee Cooper	Terry L Blackwell	Abstain	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	<a href="#">View</a>
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Abstain	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Abstain	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	<a href="#">View</a>
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Vermont Electric Power Company, Inc.	Kim Moulton		
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox		
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles Yeung		
3	AEP	Michael E DeLoach	Affirmative	<a href="#">View</a>
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	Anaheim Public Utilities Dept.	Kelly Nguyen	Abstain	
3	APS	Steven Norris	Abstain	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	<a href="#">View</a>
3	City of Alexandria	Michael Marcotte	Negative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Roseville	Susan E Gill-Zobitz	Abstain	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy	Richard Blumenstock	Abstain	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	<a href="#">View</a>
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia Systems Operations Corporation	William N. Phinney	Abstain	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Sam Kokkinen	Affirmative	<a href="#">View</a>
3	Gulf Power Company	Paul C Caldwell	Affirmative	

3	Harney Electric Cooperative, Inc.	Shane Sweet	<a href="#">Abstain</a>	
3	Holland Board of Public Works	William Bush	<a href="#">Affirmative</a>	
3	Hydro One Networks, Inc.	David Kiguel	<a href="#">Affirmative</a>	
3	Imperial Irrigation District	Jesus S. Alcaraz	<a href="#">Affirmative</a>	
3	JEA	Garry Baker	<a href="#">Affirmative</a>	
3	Kansas City Power & Light Co.	Charles Locke	<a href="#">Affirmative</a>	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik	<a href="#">Abstain</a>	
3	Louisville Gas and Electric Co.	Charles A. Freibert	<a href="#">Affirmative</a>	
3	Manitoba Hydro	Greg C. Parent	<a href="#">Negative</a>	<a href="#">View</a>
3	Mississippi Power	Jeff Franklin	<a href="#">Affirmative</a>	
3	Municipal Electric Authority of Georgia	Steven M. Jackson		
3	Muscatine Power & Water	John S Bos	<a href="#">Affirmative</a>	
3	Nebraska Public Power District	Tony Eddleman	<a href="#">Affirmative</a>	
3	New York Power Authority	Marilyn Brown	<a href="#">Affirmative</a>	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	<a href="#">Affirmative</a>	
3	Northern Indiana Public Service Co.	William SeDoris	<a href="#">Negative</a>	<a href="#">View</a>
3	NRG Energy Power Marketing, Inc.	Rick Keetch		
3	Ocala Electric Utility	David Anderson	<a href="#">Affirmative</a>	
3	Orange and Rockland Utilities, Inc.	David Burke	<a href="#">Affirmative</a>	
3	Oregon Trail Electric Cooperative	ned ratterman	<a href="#">Affirmative</a>	
3	Orlando Utilities Commission	Ballard K Mutters	<a href="#">Affirmative</a>	
3	Owensboro Municipal Utilities	Thomas T Lyons	<a href="#">Affirmative</a>	
3	Pacific Gas and Electric Company	John H Hagen	<a href="#">Affirmative</a>	
3	PacifiCorp	Dan Zollner	<a href="#">Affirmative</a>	
3	Platte River Power Authority	Terry L Baker	<a href="#">Affirmative</a>	
3	PNM Resources	Michael Mertz		
3	Potomac Electric Power Co.	Robert Reuter	<a href="#">Abstain</a>	
3	Progress Energy Carolinas	Sam Waters	<a href="#">Affirmative</a>	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	<a href="#">Affirmative</a>	
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	<a href="#">Affirmative</a>	<a href="#">View</a>
3	Sacramento Municipal Utility District	James Leigh-Kendall		
3	Salt River Project	John T. Underhill	<a href="#">Affirmative</a>	
3	Santee Cooper	James M Poston	<a href="#">Abstain</a>	
3	Seattle City Light	Dana Wheelock	<a href="#">Affirmative</a>	<a href="#">View</a>
3	Seminole Electric Cooperative, Inc.	James R Frauen	<a href="#">Affirmative</a>	
3	Snohomish County PUD No. 1	Mark Oens		
3	South Carolina Electric & Gas Co.	Hubert C Young	<a href="#">Affirmative</a>	
3	Tacoma Public Utilities	Travis Metcalfe	<a href="#">Affirmative</a>	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	<a href="#">Affirmative</a>	
3	Tri-State G & T Association, Inc.	Janelle Marriott	<a href="#">Affirmative</a>	
3	Westar Energy	Bo Jones	<a href="#">Affirmative</a>	
3	Wisconsin Electric Power Marketing	James R Keller	<a href="#">Abstain</a>	
3	Xcel Energy, Inc.	Michael Ibold	<a href="#">Affirmative</a>	
4	Alabama Municipal Electric Authority	Raymond Phillips	<a href="#">Affirmative</a>	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	<a href="#">Affirmative</a>	
4	American Municipal Power	Kevin Koloini	<a href="#">Affirmative</a>	
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	City of Clewiston	Kevin McCarthy	<a href="#">Affirmative</a>	
4	City of Redding	Nicholas Zettel	<a href="#">Affirmative</a>	
4	City Utilities of Springfield, Missouri	John Allen	<a href="#">Affirmative</a>	
4	Consumers Energy	David Frank Ronk	<a href="#">Abstain</a>	
4	Cowlitz County PUD	Rick Syring	<a href="#">Affirmative</a>	
4	Detroit Edison Company	Daniel Herring	<a href="#">Affirmative</a>	
4	Flathead Electric Cooperative	Russ Schneider	<a href="#">Negative</a>	
4	Florida Municipal Power Agency	Frank Gaffney	<a href="#">Affirmative</a>	
4	Fort Pierce Utilities Authority	Thomas Richards		
4	Georgia System Operations Corporation	Guy Andrews	<a href="#">Abstain</a>	
4	Imperial Irrigation District	Diana U Torres	<a href="#">Affirmative</a>	<a href="#">View</a>
4	Indiana Municipal Power Agency	Jack Alvey		
4	Integrus Energy Group, Inc.	Christopher Plante	<a href="#">Abstain</a>	
4	Madison Gas and Electric Co.	Joseph DePoorter	<a href="#">Affirmative</a>	
4	Modesto Irrigation District	Spencer Tacke		
4	North Carolina Electric Membership Corp.	Bob Beadle	<a href="#">Affirmative</a>	
4	Northern California Power Agency	Tracy R Bibb	<a href="#">Affirmative</a>	

4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez		
4	Seattle City Light	Hao Li	Affirmative	<a href="#">View</a>
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhanev	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko		
5	AES Corporation	Leo Bernier	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Wind Energy Association	Natalie McIntire	Affirmative	<a href="#">View</a>
5	Arizona Public Service Co.	Edward Cambridge		
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Bayer	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas	Abstain	
5	City and County of San Francisco	Daniel Mason	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	
5	City of Tallahassee	Brian Horton	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy, Inc.	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Affirmative	<a href="#">View</a>
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	CPS Energy	Robert Stevens	Negative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	<a href="#">View</a>
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	East Kentucky Power Coop.	Stephen Ricker	Abstain	
5	Electric Power Supply Association	John R Cashin	Affirmative	
5	Energy Northwest - Columbia Generating Station	James Saucedo	Affirmative	
5	Entegra Power Group, LLC	Kenneth B Parker	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Green Country Energy	Greg Froehling	Affirmative	
5	Imperial Irrigation District	Marcela Y Caballero	Affirmative	
5	Indeck Energy Services, Inc.	Rex A Roehl	Affirmative	
5	Infigen Energy US	Pamela C Zdenek	Affirmative	<a href="#">View</a>
5	Invenergy LLC	Alan Beckham	Affirmative	
5	JEA	John J Babik		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Tom Foreman	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	

5	Manitoba Hydro	S N Fernando	Negative	<a href="#">View</a>
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego		
5	MidAmerican Energy Co.	Christopher Schneider		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern California Power Agency	Hari Modi	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oklahoma Gas and Electric Co.	Kim Morphis		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	Colin Anderson	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Gary L Tingley		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Fossil LLC	Mikhail Falkovich	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	<a href="#">View</a>
5	RES Americas Inc	Ravi Bantu	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter		
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Siemens PTI	Edwin Cano	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	<a href="#">View</a>
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M Helyer	Affirmative	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles		
6	ACES Power Marketing	Jason L Marshall	Affirmative	<a href="#">View</a>
6	AEP Marketing	Edward P. Cox	Affirmative	<a href="#">View</a>
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	RANDY A YOUNG	Abstain	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirschak	Negative	
6	Colorado Springs Utilities	Lisa C Rosintoski	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Abstain	
6	Constellation Energy Commodities Group	Brenda Powell	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager		
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Luminant Energy	Brad Jones	Affirmative	

6	Manitoba Hydro	Daniel Prowse	Negative	<a href="#">View</a>
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Orlando Utilities Commission	Claston Augustus Sunanon	Affirmative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	<a href="#">View</a>
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby		
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Abstain	
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Edward C Stein	Affirmative	
8		James A Maenner	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini		
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Volkman Consulting, Inc.	Terry Volkman	Affirmative	
9	California Energy Commission	William M Chamberlain		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Affirmative	
9	New York State Department of Public Service	Thomas Dvorsky	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck	Abstain	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	James D Burley	Abstain	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	<a href="#">View</a>
10	Southwest Power Pool RE	Emily Pennel	Affirmative	<a href="#">View</a>
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	<a href="#">View</a>

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**Individual or group. (40 Responses)**  
**Name (24 Responses)**  
**Organization (24 Responses)**  
**Group Name (16 Responses)**  
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Individual
Chris Higgins/Stephen Enyeart/Chuck Mathews/Charles Sheppard
Bonneville Power Administration
BPA thanks you for the opportunity to comment on Project 2010-07, Generator Requirements at the Transmission Interface. BPA stands in support of the proposed revisions and has no comments or concerns at this time.
Individual
Thad Ness
American Electric Power
Yes
Yes
Yes
Yes





Yes
Group
Electric Power Supply Association
Jack Cashin
Yes
All TO requirements for FAC-001-1 would apply if and when GO executes an Agreement to evaluate the reliability impact of interconnecting a third party Facility to its existing generation interconnection Facility. The execution of the agreement is necessary to comply with FAC-002-1 and start the compliance clock with the applicable regulatory authority. Thus as the Project 2010-07 Standard Drafting Team (SDT) in its technical justification has stated, "If, and only if, the existing owner of a generator interconnection Facility has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to its existing generation Facility" then FAC-001-1 should apply. EPSA concurs with SDT's conclusion. The SDT has examined the issue regarding if future requests for transmission service on the interconnection Facility and in doing so acknowledged that when that Facility adopted open access and was providing transmission service it would necessitate re-evaluation of the need for the Facility to be maintained in accordance with FAC-001-1, Requirements 2 and 4. This service would indeed prompt the necessary agreement the SDT contemplates in its technical justification of FAC-001-1. EPSA believes this serves as the necessary trigger for evaluation of Requirements 2 and 4 under FAC-001-1 for GOs.
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Group
Southwest Power Pool Standards Development Team
Jonathan Hayes
No
Based on the applicability section of FAC-001 we feel that the strike through should have been kept. It limited the requirement to just those generator owners who had agreements in place, which we feel is appropriate.
Yes
No
There is a possibility of some conflict with the Bulk Electric System Definition. This should be consistent with the Transmission Owner requirements if the lead is determined part of the BES.

No
The effective dates should be consistent with the original standard. If there is a reason for the extension we would like to know why.
Yes
Yes
Yes
No
We agree that the standards being addressed are correct. See above comments. There are some issues with the determination of which facilities are deemed BES since ownership of what may be a BES facility may not always be by a Transmission Owner. All relevant standards should apply to BES facilities regardless of ownership.
Individual
John Bee on behalf of Exelon
Exelon
Yes
Yes
No
FAC-003 - Exelon supports the one mile length qualifier, but feels that additional clarification is needed to determine the points of demarcation. There are too many differing physical configurations to use a "fence line" as a determination of applicability. Suggest that the tie line length be defined as "from the Generator Step up Transformer GSU to the point of interconnection between the GO and TO owned equipment." Also suggest that the standard define what constitutes a generation station switchyard.
Yes
Yes
Yes
Yes
Yes
PRC-004 - suggest that the Standard state that responsibility for the analysis of misoperations of protective equipment shall be the responsibility of the owner of the protective equipment.
Individual
Dennis Sismaet
Seattle City Light
Yes
Key points are that (1) an executed agreement is required before evaluations of impacts are necessary and (2) this only applies when a third party is connecting to the generating interconnection line.

Yes
The proposed changes for FAC-001-1 state a 45 day period to complete the evaluation. Not sure what the question is referring to regarding " 1 year "?
Yes
Key points are the greater than one mile with clear statement of "...beyond the fenced area of the generating switchyard."
Yes
The explanation deals with the fact that there are simultaneous revisions of FAC-003 underway by two different teams.
Yes
Yes
Yes
Yes
Individual
Michelle D'Antuono
Ingleside Cogeneration LP (Occidental Chemical)
No
Unfortunately, the vital point of this requirement revolves around whether or not a Generator Owner is compelled externally to allow access to their interconnection facilities. If the GO is driving the connection for financial or other business reasons, there is no reason they should not be responsible for developing AND maintaining a facility connection requirements document. Otherwise, when the local transmission system requirements change for any reason, there will be no entity responsible to ensure that the third party will conform as well. Conversely, if the GO should be compelled to allow access to a third party, it is the responsibility of the "compeller" to handle all the related reliability studies and documents. This may include the development of a CFR which separates reliability tasks between the GO and other entities – especially if a TSP registration is required. This ensures that the Regional Entity, PUC, RTO, or other regulator must budget dollars and resources directly related to their action – not cause them to be directed to a GO.
No
Based upon similar issues addressed in Compliance Application Notices (CANs), the drafting team needs to specify how the requirements apply to an in-place "executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System." In the view of Ingleside Cogeneration LP, if the Agreement takes effect even one day before FAC-001-1 does, requirements R2 and R3 do not apply. Without this clarification, it is possible that NERC's Compliance team will apply the requirements retroactively – with minimum industry input.
No
Ingleside Cogeneration LP is very concerned that the attempt to develop "bright-line" criteria to assign applicability to either version of FAC-003 is misplaced. As seen with NERC's recent proposed directive related to Generator-Transmission interconnections, those thresholds can be arbitrarily reduced based upon regulators aversion to risk – not scientific evidence. (As it stands today, NERC has proposed any interconnection facility operating at 100 kV or higher and greater than 3 spans in length be applicable – which is even stricter than the TO thresholds in FAC-003.) This would suggest that a reliability assessment consistent with the TPL standards must be the determining factor. If the Planning Coordinator or Transmission Planner can show that the Generator-Transmission interconnection could contribute to a violation of an SOL or IROL, then a vegetation management program may be in order. Furthermore, there needs to be some level of common sense applied if a

GO-TO interconnection is located in an area where vegetation clearance is never an issue. A one-size-fits-all requirement based upon vegetation growth in the sub-tropics, should not automatically apply in the desert. In our view, every dollar spent to control vegetation in an arid climate is one less dollar available to purchase advanced telemetry, AGC systems, and other items which have a far greater impact on reliability.

No

Based upon similar issues addressed in Compliance Application Notices (CANs), the drafting team needs to specify when the first vegetation management inspection quarterly report, and any other requirement with an assigned interval in FAC-003-3 or FAC-003-X. Even if the decision is to adopt the same criteria proposed in CAN-0012, the industry is better served with a clear distinction made up front.

Yes

Ingleside Cogeneration agrees that the SDT's approach is thorough. We are far more concerned about FAC-003's applicability criteria and implementation time frame at this point – as stated in our responses to questions 3 and 4.

Yes

Ingleside Cogeneration LP believes the SDT has spent a significant amount of time and effort to demonstrate that only FAC-001, FAC-003, and PRC-004 need to be modified to address any reliability gaps that may exist related to the GO-TO interconnection. We agree that the other standards/requirements identified by the Ad Hoc Group are covered elsewhere.

Yes

Although the SDT is nearing conclusion on the closing of reliability gaps, the unnecessary registration of GOs and GOPs as TOs and TOPs is far from resolved in our view. Ingleside Cogeneration's concern is based upon NERC's recent proposal to dictate an interim GO-TO interconnection solution which completely bypasses the Standards Development Process. Frankly, it seriously brings to question the nature of the consensus-driven process – which appears to be moving in a dictatorial direction.

No

See comments to questions 1 through 4.

Ingleside Cogeneration LP believes that the set of standards proposed by the SDT is technologically accurate and defensible. The open issue is if the ERO and FERC expect more standards to be included – whether based upon sound reliability principals or not.

Group

Northeast Power Coordinating Council

Northeast Power Coordinating Council

Guy Zito

Guy Zito

No

The intent of the draft language in FAC-001-1 is to provide guidance for addressing the alleged reliability gap that exists between GO/GOPs that own/ operate transmission facilities but are not registered as TO/TOPs. The impact of the revised language will depend on the characterization of the generator lead after the "third party " connects to the existing generator lead. IF the generator lead is owned by the TO utility after the third party connection : The proposed DRAFT FAC-001 language suggests that within 45 days of a 3rd party having an executed Agreement to evaluate the reliability impact of interconnecting, the existing generator needs to document and publish facility connection requirements. The proposed language suggests that a third party can commandeer existing generators leads and interconnect. A reclassification would be required because "third party" power would flow through the downstream portions of the existing leads. This introduces significant challenges for defining ownership / transfer of installed assets as well as real property, easements, operational jurisdiction, O&M cost responsibility, etc. The FERC approved pro-forma Attachment X Interconnection Agreement clearly states that the project Developer must meet all Applicable Reliability Standards which means that all requirements and guidelines of the Applicable Reliability Councils, and the Transmission District to which the Developer's Large Generating Facility is directly interconnected. As an example, to accommodate this NERC proposal, the FERC approved NYISO pro-

forma tariff would need to be revised to allow this "third party" use. The pro-forma interconnection tariff also states that the Developer must provide updated project information prior to the Facilities Study. The Facilities Study might not be made until several years after the Interconnection Request /Feasibility Study is made ("executed Agreement to evaluate the reliability impact of interconnecting" in this proposed draft is akin to the Interconnection Request/Feasibility Study). Placing the requirement to have the existing Generator Owner publish reliability requirements for a potential "third party user", without the generator having any knowledge of the potential reliability outcomes or asset transfer / ownership issues is not a reasonable expectation. The interconnection of a third party to an existing generator lead would force existing generators to revise their Interconnection Agreements with FERC. The "third party", would at a minimum, need to comply with the existing Generators reliability obligations as specified in the Interconnection Agreement. IF the third party connects to the GO owned generator lead, the GO will be considered a TO: A TO would not be involved, other than review of the SRIS and Facilities reports. The difficult thing for an existing GO would be to prepare, within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility, a document listing the requirements. To allow for the above possibilities, the language for applicability of FAC-001 to GO's or GOP's, should be : "Each applicable Generator Owner shall, at least 60 days prior to execution of a Facilities / Class Year Study Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission System, document and publish its Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, sub regional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements."

Yes

No

Suggest in FAC-003-X; 4.3.1. that Regional Entity be changed to RE as listed in 4.2.1 for consistency. Also Regional Entity is used throughout the rest of the document, suggest using RE for consistency. In FAC-003-3; 4.3.1. add station to the following: " Overhead transmission lines that extend greater than one mile or 1.609 kilometers beyond the fenced area of the generation station switchyard and are" to show consistency as it is written in FAC-003-X 4.3.1. The technical justification characterized the exclusion (i.e., one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard) as "approximate line of sight [sic] from a fixed point" and noted that this line of sight may be limited by local terrain. Where line of sight of the radial corridor is limited on a clear day due to terrain, the one mile exemption must be limited in distance to no more than the line of sight on a clear day beyond the fenced area.

Yes

Yes

Yes

Yes

Yes

No additional comments.

Individual

Michael Falvo

Independent Electricity System Operator

Yes

Yes
Yes
Yes
Yes
Yes
Yes
Group
Southwest Power Pool Regional Entity
Emily Pennel
Yes
No
No action is required unless a GO has an executed third-party agreement. If a GO has an agreement, the standard already includes a 45-day timeframe for the GO to document and publish its facility connection requirements.
Yes
Yes
Yes
No
The Technical Justification document did not review the standards FERC identified in paragraphs 71 and 87 of 135 FERC ¶ 61,241 ORDER DENYING APPEALS OF ELECTRIC RELIABILITY ORGANIZATION REGISTRATION DETERMINATIONS. The SDT needs to review these standards to determine if changes are needed; otherwise, FERC will require registration of GOs and GOPs as TOs and TOPs to address reliability gaps. If the SDT determines no changes are needed to these FERC-identified standards, they should provide justification.
The SDT should consider the standards that FERC identified in 135 FERC ¶ 61,241.
Individual
Greg Rowland
Duke Energy
Yes
Yes
Yes

Yes
Yes
Yes
Yes
Yes
Individual
Darryl Curtis
Oncor Electric Delivery Company LLC
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Individual
Kirit Shah
Ameren
Yes
Yes
No
(a) There is no technical basis for the one mile length exemption. In fact, one could argue that a very short line, 300 feet in length, that experienced a fault from a tree at "the end of the circuit", i.e near the switchyard fence, would have much more of an impact on the BES because the fault would be limited by much less impedance. (b) It is unclear in this version if a GO that owned one line that was 1.2 miles in length, and fifty other lines that did not exceed 500' in length would have to comply for all fifty-one lines or not. It would appear that they would as they owned at least one more than a mile. This ambiguity should be removed.



No
The 2 year compliance time line is far too long. There is significant industry evidence that was developed in the drafting of Version 2 that supports a one year compliance time-line for new lines. This is evidenced in Version 2. Thus there is no basis for the 2 years.
(a) There is no technical basis for the one mile length exemption. In fact, one could argue that a very short line, 300 feet in length, that experienced a fault from a tree at "the end of the circuit", i.e near the switchyard fence, would have much more of an impact on the BES because the fault would be limited by much less impedance. (b) It is also unclear in this version if a GO that owned one line that was 1.2 miles in length would have to comply for the entire length of said line, or just 0.2 miles of said line. If the GO is responsible for 1.2 miles, then that argues that the first mile is important and consequently there is no basis for ignoring the first mile on other lines. If the GO is only responsible for 0.2 miles, what is the technical basis to ignore a mile? And would it be the first mile from the switchyard that is ignored, or is the middle mile, or the last mile where it connects to the TO? Or could the GO decide? Or could the GO pick sections of the line that amount to a mile that they can ignore? This seems like something that should be addressed for compliance. (c) The 2 year compliance time line is far too long. There is significant industry evidence that was developed in the drafting of Version 2 that supports a one year compliance time-line for new lines. This is evidenced in Version 2. Thus there is no basis for the 2 years
Yes
No
Please refer to our comments in responses to #3, #4, and #5 above.
Individual
John Seelke
PSEG
No
We revised this partial sentence to the following: "Each applicable Generator Owner shall, within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Transmission Facility that is used for connection to the interconnected Transmission systems (under FAC-002-1), ..." - The phrase "Generator Owner's existing Facility that is used to interconnect to the Transmission System" was changed to "Generator Owner's existing Transmission Facility that is used for connection to the interconnected Transmission systems." - "Transmission" was added before Facility to exclude connections elsewhere; "Transmission System" was changed to "Transmission systems" because while "Transmission" and "System" are defined in the NERC Glossary, "System" means "A combination of generation, transmission, and distribution components." "Transmission systems" do not have generation or distribution components, so a lower case "system" is warranted. - In addition, the suggested phrase "interconnected Transmission systems" (plural "systems") uses identical language from FAC-002-1, except that we capitalized "Transmission."
Yes
No
No
It's no longer applicable.
Yes
No
PRC-005-1 - Transmission and Generation Protection System Maintenance and Testing was recommended by the Ad Hoc Group for modification, but not addressed to the technical justification document. It should be.

No
It would be helpful if the SDT defined what it means by the term “radial generator interconnection Facilities.” Does it mean interconnection Facilities that under Normal Clearing for a fault do not interrupt flows on other BES Elements? This is also confusing because of the radial exclusion included in the BES definition work in Project 2010-17. That definition would allow part of a three-terminal circuit to be excluded from the BES, while the other parts are included in the BES.
No
Yes
We believe that the Ad Hoc Group’s suggestions regarding PRC-005-1 - Transmission and Generation Protection System Maintenance were correct and that this standard should have been modified by the SDT in a manner similar to the way the SDT modified PRC-004-2. This would require modifying R1 and R2 in PRC-005-1a (the current version) to include protection systems in the generator interconnection Facility. In addition, the SDT should evaluate modifying PER-002-0 – Operation Personnel Training. In doing so the SDT completes one of the open FERC directives in Order 693. Paragraph 1363 addresses GOP training: 1363. Further, the Commission agrees with MidAmerican, SDG&E and others that the experience and knowledge required by transmission operators about Bulk-Power System operations goes well beyond what is needed by generation operators; therefore, training for generator operators need not be as extensive as that required for transmission operators. Accordingly, the training requirements developed by the ERO should be tailored in their scope, content and duration so as to be appropriate to generation operations personnel and the objective of promoting system reliability. Thus, in addition to modifying the Reliability Standard to identify generator operators as applicable entities, we direct the ERO to develop specific Requirements addressing the scope, content and duration appropriate for generator operator personnel.
Group
MRO NSRF
Will SMith
Yes
Yes
No
The NSRF agrees with the drafting committees desire to eliminate arbitrary and capricious behavior of auditors and industry staff by precisely defining the point at which measurement starts for the length of transmission line. The concern the NSRF has with the proposed wording is that many generating station may not have a “generating station switchyard” as implied by the proposed wording. Often the generator leads (e.g. 20 kV) will exit the generator and connect to transformers located in transformer bays directly adjacent to the plant. From the transformers the now greater than 200 kV lines will be routed to the point of interconnect or a generating unit switchyard, possibly miles or yards away. By no one’s definitions would the transformer bays adjacent to the plant be considered a switchyard. The plant fence may be yards or hundreds of yards from the bays and on a multiple unit site, there may be a site fence or boundary, which could be comprise of fences, security patrols, or other barriers yards or miles from the transformer but enveloping the switchyard. The valid assumption made by the drafting team is that transmission lines within an area tightly controlled by the generator operator poses very little risk to the BES as a result of vegetation contact. This assumption is based on the valid observation that these areas are routinely occupied and observed by station personnel and as a result unexpected and unacceptable vegetation growth is highly unlikely because it is controlled by routine maintenance. It also correctly assumes that some distance past the controlled area is acceptable since this area would also be under near continuous observation. The problem comes in defining both a tightly controlled area and a line of site. We suggest the following: Controlled Area: A perimeter around a power plant, power plants, or switchyard which is prevents intrusion by the use of physical barriers, observation, or electronic monitoring and is routinely occupied such that unexpected and unacceptable vegetation growth would be observed and correct as a matter of routine maintenance. Line of Sight: NSRF recommends a two kilometer distance from the

controlled area perimeter. Our assessment is that an individual of average height would have a line of sight of approximately 4 Kilometers. Therefore, we recommended a distance of 2 kilometers from the Controlled Area of the plant to provide margin. The revised applicability statement would read as follows: "Generator Owner that owns an overhead transmission line(s) that extends greater than 2.0 kilometers beyond the Controlled Area of the generating station up to the point of interconnection with a Transmission Owner's Facility and is operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region. Furthermore we applaud the committee for using the metric system to identify the acceptable distance for this standard and urge it to remove all references to English units. We strongly suggest this drafting team and all future drafting team abandon the anachronistic English measurement system. This archaic system, based on the length of an average barley corn, should be abandon in all scientific and engineering endeavors.

Yes

There may be a typographical error on the effective date. As currently drafted the standard states: In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption. Should it be worded as follows? In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 R1 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

Yes

No

The NSRF has one concern with the current justification and definitions. At some point, if enough interconnections are made to generator outlet leads in accordance with FAC-001, the original generator operator will be a Transmission Operator and a Transmission Owner. This point in time needs to be explicitly defined by the drafting team.

Yes

Yes

The NSRF agrees if the drafting team incorporates as suggested improvements

Individual

Andrew Z. Pusztai

American Transmission Company

Yes

Yes

Yes

Yes

Yes

Yes

Yes
Yes
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Yes
Yes
No
There should be no qualifying exemption to FAC-003 for Generator Owners.
Yes
Yes
Yes
No
The modifications are appropriate with the exception noted in question #3.
Group
American Wind Energy Association
Natalie McIntire
Yes
AWEA appreciates that this standard specifies that it has limited applicability. For instance, only those generators that have an executed agreement with a third party wishing to interconnect must document and publish Facility connection requirements. We believe the proposed 45-day time window is a minimum for GO/GOP owners of generator lead lines to provide this documentation following execution of such an agreement. Anything less than 45 days could result in a burdensome and hard to meet deadline for GO/GOP staff. However, AWEA believes that extending this time window for publishing Facility connection requirements to 90 days after an executed agreement would be beneficial. We believe this will allow the GO/GOP owners of generator leads more time to coordinate with their interconnecting Transmission Providers and will result in more reliable and coordinated connection requirements for the generator lead.
Yes
Yes, since there is no exigent reason why this standard needs to be put in place at once, we support the one-year compliance timeframe. We believe that it will allow generators a reasonable time to comply with the requirement.
Yes
Applying the vegetation management requirements to only generator lead lines that extend more than "one mile beyond the fenced area of the generating station switchyard" strikes a reasonable balance among the many stakeholder positions expressed on this topic. We think that as this criterion recognizes that there is little need for a vegetation management plan for shorter lines. It should explicitly state that this is true for all such facilities with lines of that length or smaller.

Yes
Yes, as with our comments to question 2, since there is no exigent reason why this standard needs to be put in place at once, we support the proposed compliance timeframe. We believe that it will allow generators a reasonable time to comply with the requirement.
Yes
Yes
The reasoning of the SDT is comprehensive and makes a strong case for why there is no need for additional standards to be applied to GO/GOP lead lines as they will not improve the reliability of the Bulk Electric System. In fact, as noted above, such additional standards may decrease reliability by diverting the GO/GOP's resources from the operation of the equipment that actually produces electricity – the generation equipment itself.
Yes
AWEA believes that the standards modifications proposed by the SDT should address any genuine reliability gap with regard to generator lead lines, rather than just perceived but unsupported threats. To that end, we support the approach that the SDT appears to be taking of modifying a limited number of applicable standards so that they apply to GO/GOP lead lines. In particular, we fully support the fact that the SDT recognizes that GO/GOPs should not automatically be required to register as TO/TOPs simply because of their ownership of generator lead lines. The SDT correctly recognizes that such registration should be done based on a case-by-case determination. As already noted, registering a GO/GOP as a TO/TOP may actually decrease reliability.
Yes
For the most part, AWEA agrees that the SDT proposal strikes a reasonable balance and provides the requisite level of clarity and certainty necessary for GO/GOPs to understand their responsibilities and compliance requirements.
AWEA appreciates the opportunity to submit these comments on the NERC Project 2010-07. AWEA supports the general direction indicated by both the Generator Requirements at the Transmission Interface Ad Hoc Group and the Project 2010-07 Standards Development Team. We agree with the sentiments from both groups that a GO or GOP that also owns or operates a generator lead line should not be required to register as a TO or TOP strictly because they own or operate a generator lead line. We also agree that requiring these GO/GOPs to comply with all the TO/TOP standards would have little effect on or benefits to reliability of the Bulk Electric System, and could even detract from it. AWEA supports the intent and goal of the SDT to ensure that all generator-owned Facilities are appropriately covered under NERC's Reliability Standards. We also agree with the SDT that while many GO/GOPs operate Elements and Facilities that might be considered by some entities to be Transmission, these are most often radial Facilities that are not part of the integrated grid, and as such should not be subject to the same standards applicable to TO/TOPs, who own and operate Transmission Elements and Facilities that are part of the integrated grid. Therefore, we support the SDT's approach of identifying a very limited number of TO/TOP standards, such as FAC-001 and FAC-003, which should also apply to GO/GOP owners of generator lead lines. We would be concerned, however, if additional requirements were added beyond FAC-001, FAC-003, and PRC-004. Consideration of any additional standards with respect to generator lead lines should be done on a standard-by-standard basis, reviewing the applicability of each standard as well as the impact on the reliability of the Bulk Electric System.
Group
SERC Planning Standards Subcommittee
Charles W. Long
Yes
Yes
No
We believe there should be no exemption for Generator Owners.

Yes
Yes
Yes
Yes
No
See our comments above for question # 3.
The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers”
Group
Puget Sound Energy, Inc.
Tom Flynn
The changes to this standard are minor, and seem to be centered around including "generator Interconnection facilities" to R2. This added phrase and the statement in 1.4 Data Retention "Generator Owner that owns a generation Protection System" seems to assume that the generator owner and generator interconnection facilities owner is always the same. This is not always the case, and will make this standard language confusing to prepare evidence for. A suggestion would be to revise the language to allow for a separate generator owner and generator interconnection facilities owner.
Individual
Ravi Bantu
RES Americas Development
Yes
RES Americas and AWEA appreciate that this standard specifies that it has limited applicability. For instance, only those generators that have an executed agreement with a third party wishing to interconnect must document and publish Facility connection requirements. We believe the proposed 45-day time window is a minimum for GO/GOP owners of generator lead lines to provide this documentation following execution of such an agreement. Anything less than 45 days could result in a burdensome and hard to meet deadline for GO/GOP staff. However, we believes that extending this time window for publishing Facility connection requirements to 90 days after an executed agreement would be beneficial. We believe this will allow the GO/GOP owners of generator leads more time to coordinate with their interconnecting Transmission Providers and will result in more reliable and coordinated connection requirements for the generator lead.
Yes
Yes, since there is no exigent reason why this standard needs to be put in place at once, we support the one-year compliance timeframe. We believe that it will allow generators a reasonable time to comply with the requirement.

Yes
Applying the vegetation management requirements to only generator lead lines that extend more than “one mile beyond the fenced area of the generating station switchyard” strikes a reasonable balance among the many stakeholder positions expressed on this topic. We think that as this criterion recognizes that there is little need for a vegetation management plan for shorter lines, it should explicitly state that this is true for all such facilities with lines of that length or smaller.
Yes
Yes, as with our comments to question 2, since there is no exigent reason why this standard needs to be put in place at once, we support the proposed compliance timeframe. We believe that it will allow generators a reasonable time to comply with the requirement.
Yes
Yes
The reasoning of the SDT is comprehensive and makes a strong case for why there is no need for additional standards to be applied to GO/GOP lead lines as they will not improve the reliability of the Bulk Electric System. In fact, as noted above, such additional standards may decrease reliability by diverting the GO/GOP's resources from the operation of the equipment that actually produces electricity – the generation equipment itself.
Yes
We believe that the standards modifications proposed by the SDT should address any genuine reliability gap with regard to generator lead lines, rather than just perceived but unsupported threats. To that end, we support the approach that the SDT appears to be taking of modifying a limited number of applicable standards so that they apply to GO/GOP lead lines. In particular, we fully support the fact that the SDT recognizes that GO/GOPs should not automatically be required to register as TO/TOPs simply because of their ownership of generator lead lines. The SDT correctly recognizes that such registration should be done based on a case-by-case determination. As already noted, registering a GO/GOP as a TO/TOP may actually decrease reliability.
Yes
For the most, we agree that the SDT proposal strikes a reasonable balance and provides the requisite level of clarity and certainty necessary for GO/GOPs to understand their responsibilities and compliance requirements.
RES and AWEA appreciates the opportunity to submit these comments on the NERC Project 2010-07. We support the general direction indicated by both the Generator Requirements at the Transmission Interface Ad Hoc Group and the Project 2010-07 Standards Development Team. We agree with the sentiments from both groups that a GO or GOP that also owns or operates a generator lead line should not be required to register as a TO or TOP strictly because they own or operate a generator lead line. We also agree that requiring these GO/GOPs to comply with all the TO/TOP standards would have little effect on or benefits to reliability of the Bulk Electric System, and could even detract from it. RES and AWEA supports the intent and goal of the SDT to ensure that all generator-owned Facilities are appropriately covered under NERC's Reliability Standards. We also agree with the SDT that while many GO/GOPs operate Elements and Facilities that might be considered by some entities to be Transmission, these are most often radial Facilities that are not part of the integrated grid, and as such should not be subject to the same standards applicable to TO/TOPs, who own and operate Transmission Elements and Facilities that are part of the integrated grid. Therefore, we support the SDT's approach of identifying a very limited number of TO/TOP standards, such as FAC-001 and FAC-003, which should also apply to GO/GOP owners of generator lead lines. We would be concerned, however, if additional requirements were added beyond FAC-001, FAC-003, and PRC-004. Consideration of any additional standards with respect to generator lead lines should be done on a standard-by-standard basis, reviewing the applicability of each standard as well as the impact on the reliability of the Bulk Electric System.
Individual
Katy Wilson
Sempra Generation





rare. 3) If the redline changes are implemented, GOs are removed from R4, thereby removing the obligation for GOs to maintain their connection requirements. If GOs are included in FAC-001, they should be held accountable to the same level as TOs and should be required to maintain their connection requirements. Requiring a GO to maintain connection requirements would be especially beneficial to the GO themselves. In the majority of instances, any GO that is an Applicable Entity for FAC-001 would initially be inexperienced in performing interconnection studies and would benefit from regular and frequent review of their connection requirements as experience and expertise are gained. 4) The revision to FAC-001-1 R2 may be problematic, depending on what was intended. Under the revised requirement, the obligation to comply is dependent on the execution of an agreement to evaluate reliability impacts under FAC-002-1. However, FAC-002-1 does not clearly require the execution of an agreement by the Generator Owner. FAC-002-1 only requires the Generator Owner to "coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority". Accordingly if a Generator Owner coordinates without executing an agreement to perform an assessment, compliance with FAC-001 R1 will not be required. 5) Manitoba Hydro would also like to point out that if the redline changes are implemented, it will greatly increase the complexity of coordination required under FAC-002-1 for Transmission Planners/Planning Authorities.

No

See question 1 comments.

No

Manitoba Hydro does not support the changes being proposed in this project. If a Generator Owner is required to register as a TO, all the Requirements applicable to a TO should apply. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions.

No

See question 3 comments.

No

See question 3 comments.

No

See Question 7 comments.

No

The SDT's proposed modifications gives special treatment to the Generator Owner in that it allows the Generator Owner TO status for a couple of standards (FAC-001, FAC-003 and PRC-004), but exempts the Generator Owner from many of the standards applicable to a TO. The NERC Registry Criteria defines the various functional entities. If a Generator Owner wants to own transmission facilities and it falls under the definition of a Transmission Owner under the NERC Registry Criteria, then all the Requirements applicable to a TO should apply. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. Reliability gaps would be better closed if select GOs and GOPs simply registered as TOs and TOPs. At this time, this would not lead to a large number of extra registrations since, as stated in the technical justification document, 'interconnection requests for Generator Owner Facilities are still relatively rare.

No

See question 7 comments.

No additional comments.

Group

Florida Municipal Power Agency

Frank Gaffney

Yes

Yes

Yes

Yes
Yes
No
see comment to Question 7
FMPA believes that TOP-004-2 R6.2 ought to also be addressed in the standards as applicable to GOPs. The requirements reads: R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: R6.2. Switching transmission elements. Although planned outages are covered in other standards applicable to a GOP, switching to close / synchronize a generator back to the system is not specifically covered in the standards. Some have argued that TOP-002-2 R3 causes GOPs to coordinate its current day plans with the TOP; however, the name of the standard is "Transmission Operations Planning" and therefore implies the availability of the generator and related equipment and not necessary implies the policies and procedures for switching operations; which includes synchronization. FMPA cannot imagine a generator that would not have such switching / synchronization policies and procedures coordinated with its interconnecting TOP; as such would normally be required through a Large Generator Interconnection Agreement through a pro forma OATT; however, FMPA is not aware of any instance in the standards that covers this. As such, FMPA recommends including TOP-004-2 R6.2 as being applicable to a GOP.
see response to Question 7
Group
Dominion
Mike Garton
Yes
Yes
No
Dominion suggests in FAC-003-X; 4.3.1. Regional Entity be changed to RE as listed in 4.2.1 for consistency. Also Regional Entity is used throughout the rest of the document, suggest using RE for consistency overall. Dominion suggests in FAC-003-3; 4.3.1. adding station to the following "Overhead transmission lines that extend greater than one mile or 1.609 kilometers beyond the fenced area of the generation station switchyard and are" to show consistency as it is written in FAC-003-X 4.3.1. Further, Dominion is concerned that the technical justification characterized the exclusion (i.e., one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard) as "approximate line of sign [sic] from a fixed point" and notes that this line of sight may be limited by local terrain. Where line of sight of the radial corridor is limited on a clear day due to terrain, the one mile exemption must be limited in distance to no more than the line of sight on a clear day beyond the fenced area.
Yes
Yes
Yes
Yes

Yes
No
Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.
No
The language for FAC-001 Requirement R2 should be: "This requirement shall apply to each applicable Generator Owner. Generator Owner filings must be made at least 60 days in advance of execution of the final interconnection study agreement in the Planning Coordinator's or Transmission Planner's study process. Each applicable Generation Owner must publish its Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, sub regional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements. The evaluation of the reliability impact(s) of interconnecting a third party Facility to the Generator Owner's existing Facility utilized for interconnection to the Transmission System must be documented."
Individual
Ed Davis
Entergy Services
Yes
Yes
Yes
We suggest that the Vegetation Management Standards should be consistent for both the TO and GO facilities. We would also like to suggest an additional Recommendation for added clarity regarding Category 3 Outages (Off-ROW Fall-in Outages). We understand that the Category 3 Outages are not a violation of the Standard, but we feel that there should be some level of comment added within the Standard clearly stating that these Outages are "Reportable Only" during the Quarterly Outage reports to the RE's, and that there are no associated violations/sanctions for this Category Of Outage, and that an Off-ROW fall-in outage would not be considered an encroachment into the MVCD in any way. The Technical Reference Document does a good job of clearly stating this in the Introduction on Page 5 ("This standard is not intended to address outages such as those due to vegetation fall-ins or blow-ins from outside the Right-of-Way, vandalism, human activities or acts of nature.") and we feel

that this should also be stated clearly in the Standard.
Individual
Alice Ireland
Xcel Energy
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Individual
Russell A. Noble
Cowlitz County PUD
Yes
Yes
Cowlitz PUD (District) registered as a Transmission Owner shortly before FAC-001-0 became effective and was forced to file a Mitigation Plan in order to facilitate compliance. The District successfully completed compliance implementation and documentation in eight months. The proposed one year compliance timeframe is sufficient.
Yes
Yes
Yes
Yes
Yes
Yes
No
N/A
In answer to the SDT request for feedback on FERC's Order concerning Cedar Creek and Milford, the District finds no technical reason to add any of the listed standard requirements, and struggles to understand why FERC would even consider this listing as applicable.



bring a uniform, fair and technically supported approach that resolves the interface issue. Thus, NextEra requests that the SDT (prior to proceeding any further or any additional comments or votes on specific draft Reliability Standards) issue a technical paper that point-by-point addresses the merits of including the Reliability Standards set forth in the FERC Orders and NERC's draft interim directive, and request stakeholder, including NERC staff, comment. For example, this technical paper would likely the merits of NERC's draft interim directive not requiring NERC-certified operators (but require training of interface operators), while FERC's orders require NERC-certified operators. While NextEra does not agree five days of training is necessary for an interface operator, as the draft interim directive appears to propose, NextEra does believe a technical case can be made why NERC-certification is not required, and that some degree of training related to the applicable Reliability Standards is reasonable. Similar, on FAC-003 (as well as several other Standards), the draft interim directive proposes a slightly different approach than the SDT. NextEra would rather these approaches reconciled than be in conflict, with the potential for continued conflict as the SDT's work product proceeds. Further, NextEra requests that the SDT's review the technical merits of NERC's proposed criteria to determine what generator transmission lead is required to comply with additional Reliability Standards. As noted, above, this technical paper should be posted for stakeholder, including NERC staff, comment. Accordingly, while NextEra would have preferred that NERC and the Regional Entities express there interim draft directive approach on the record in this proceeding, NextEra believes it is appropriate for the SDT to draft a comprehensive technical paper that, with an open approach, considers the inclusion of additional Reliability Standards, if appropriate, as a way of building lasting support for its approach.

Individual

Anthony Jablonski

ReliabilityFirst


ReliabilityFist has found a number of editorial erros for the FAC-001-1 VSLs. They include the following: 1. VSL R1 – should not reference sub-requirements, should reference the sub-parts consistent with the requirement (i.e. Requirement R1, Part 1.1, 1.2 or 1.3) 2. VSL for R3 – the VSL should referenced Requirement 3, Part 3.1.1 through 3.1.16 rather than what is currently stated (Requirement R3, Part 3.1.1 R3.1.6)

Individual

Donald Jones

Texas Reliability Entity

No

In Section 5.1, the reference to Regional Entity should be removed. There are no requirements that apply to the Regional Entity. In Requirements R1 and R4, "Planning Coordinator" should be added after "Regional Entity." In the ERCOT Region it is the Planning Coordinator that maintains planning criteria and connection requirements. There is no NERC requirement or any obligation (as indicated in the technical justification document) on the part of a GO to specifically execute an Agreement to evaluate the reliability impact of interconnecting a third party Facility. Therefore, this requirement's applicability is contingent on a prerequisite that may not occur, and that is under the control of the GO. This assumption on the part of the SDT unnecessarily complicates the compliance monitoring and enforcement of this standard. For instance, if an "Agreement" is not executed, a GO is not required to comply with the requirement, even though the GO may ultimately interconnect with another entity. The requirement should be modified to include an applicability trigger similar to that of FAC-002-1, so that once a GO "seek[s] to integrate . . ." i.e., agrees to or is compelled to allow a third-party

interconnection, then the requirement becomes applicable. Otherwise, the compliance and monitoring is subject to the SDT's speculation as indicated in this language included in the technical justification document: "However, the SDT cannot be certain this is the only example and it therefore proposes to add this new requirement to FAC-001-1. In doing so, the SDT acknowledges that the Generator Owner may not, at the time it agrees or is compelled to allow a third party to interconnect, have the necessary expertise to conduct the required interconnect studies to meet this standard. Assuming that a regulatory body would require a Generator Owner to evaluate such an interconnection request, the SDT expects the Generator Owner and the third party to execute some form of an Agreement."

Yes

In the description of the "second effective date" in FAC-003-X there is an erroneous reference to "Requirement R3," which should be corrected to "Requirement R1."

No

A compliance timeframe for the applicable GOs of two years is too long and the scenario used as a basis provides no timing specifics or details. Moreover, the 12 months for an existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard is arguably the same situation as an applicable GO but the applicable GO has an additional 12 months to come into compliance.

Yes

No

Our negative votes on FAC-003 reflect our concern that this project has not considered all of the applicable standards. Why did the SDT choose to only review the Ad Hoc Group's standards when there have been multiple registration appeals in which FERC and NERC have repeatedly cited specific additional TO/TOP standards that were determined to be applicable to GO/GOPs? This SDT project would serve a tremendous value to the ERO and in particular industry if it were to address the technical aspects of the following FERC ordered applicable standards: PRC-001-1 R2, R4; PRC-004-1 R1; TOP-004-2 R6; PER-003-1 R1; FAC-003-1 R1, R2; TOP-001-1a R1 and FAC-004-2 R2. The SDT team should analyze the FERC orders, the applicable standards indicated, and the circumstances and facts involved, and technically justify why no reliability gap exists if these standards are not applied to GO interface facilities. The SDT should include more "technical" information in its technical justification document. For example, in regards to TOP-004-2 R7, the SDT technical justification states that there is no reliability gap because, ". . . because an operator has a fiduciary obligation to protect a Facility for which it is operationally responsible." An entity having a fiduciary obligation is not a technical justification of why a reliability gap does not exist. Moreover, by that logic there would be no need for many standards because every registered entity has a fiduciary obligation to protect its facilities.

No

See comment 6.

No

See comment 6.

See comment 6.

Individual

Amir Hammad

Constellation Power Source Generation

Yes

Yes

Yes

Yes

Yes
Yes
Constellation supports the SDT justifications and offers additional information in our response to question 10.
Yes
Yes
Constellation appreciates and supports the work of the standard drafting team. We recognize the significant time invested by technical experts from industry to consider the appropriate application of reliability standards to address concerns raised about coverage of transmission at the generator interface. The drafting team analysis identified the standards in need of revision to appropriately address the reliability concerns raised. While the revision process focuses on specific standards, it is important to consider the reliability questions in the context of the full complement of reliability standards that apply to entities. For instance, the following standards already apply to generators and relate to the reliability considerations around transmission at the generator interface: • PRC-001-1 addresses coordination of protection system components by requiring all GOs to ensure coordination of their protection system with interconnected parties. Further, FAC-002 requires that all new facilities undergo reviews by the TOP, BA, etc. • PRC-004-1 requires all GOs to ensure that they analyze all misoperations on their protection system which would include the protection of the tie line. • TOP standards applicable to GOs aid coordination between a GO and a TO with regards to the generator tie line by requiring all GOs to coordinate all maintenance and emergency outages (both forced and planned) with all applicable interconnected parties. Further, all ISO procedures require the same of GOs. • RC, TOP and/or BA certified operators control and are responsible for overseeing that transmission. According to the NERC functional model, a Generator Operator is defined as “operat(ing) generating unit(s) and perform(ing) the functions of supplying energy and reliability related services.” Given this limited scope, the Generator Operator (GOP) cannot be considered as operating on the same level as the Reliability Coordinator, Transmission Operator or Balancing Authority when it comes to real time information on the status of the BES. The GOP does not monitor and control the BES, rather the GOP only monitors and controls the generators that it operates and relays information to other operating entities. • IRO and TOP standards applicable to GOs include tie lines in their pool of resources to alleviate operational emergencies by requiring all GOs to operate as directed by their TOP, BA, or RC as directed and must render emergency assistance. • FAC-8 and FAC-9 manage rating methodology consistency by requiring all GOs to develop a methodology to rate all equipment, and that the RC has the authority to challenge the GO on that methodology. The onus is on the GO to either change their methodology and rating accordingly, or provide a technical justification as to why they cannot adopt the changes. Further, a generator will never be limited by its tie line, as a generator’s profits are directly tied to its output. Therefore no generator would limit its facility to the equipment that is delivering that output.
Individual
Dennis Chastain
Tennessee Valley Authority
No
Suggest that the overall structure of the standard be revised such that R1 – R3 are applicable to the Transmission Owner (consistent with existing FAC-001-0) and R4 (the new requirement) is applicable to the “applicable Generator Owner”. See further comments below. Support the proposed revisions to R1 and R4, but suggest R4 be returned to R3 (consistent with existing FAC-001-0). R3 in the balloted standard should be returned to R2 (consistent with existing FAC-001-0) and only be applicable to the Transmission Owner. R3.1 (or R2.1 if moved back) should be “fixed”, but it may be beyond this SDT’s charge. The use of “above” in the FAC-001-0 standard, or the proposed reference to “Requirements R1 or R2” in the proposed standard do not make sense in combination with the colon used at the end of the requirement. Suggest that R3.1 (or 2.1 if moved back) be revised as written below and all sub-



requirements of R3.1 be elevated (R3.1.1 becomes R3.2, R3.1.2 becomes R3.3, etc.). "R3.1 Performance requirements and/or planning criteria used to assess system impacts." R2 in the balloted standard should become R4 and modified to incorporate the connection requirements contained in R3 that can more reasonably be expected of an "applicable Generator Owner". For instance, an "applicable Generator Owner" might simply have a connection requirement for a third party that addresses coordination of system impact studies with the appropriate Transmission Owner(s), in lieu of R3.1, R3.1.1, and R3.1.2. Suggest that R2 (or R4 if moved below existing FAC-001-0 requirements) be revised as written below. "R2 Each applicable Generator Owner that has agreed to allow a third party Facility owner (Generation Facility, Transmission Facility, or End-user Facility) to connect to the Transmission system through use of pre-existing applicable Generator Owner Facilities shall communicate it's Facility connection requirements to the third party. The applicable Generator Owner Facility connection requirements shall address the following items: R2.1 Coordination of system impact studies with the Transmission Owner. R2.2 Voltage level and MW and MVAR capacity or demand at point of connection. R2.3 Breaker duty and surge protection. R2.4 System protection and coordination R2.5 Metering...." Etc.

Yes

No comments

Yes

No

Group

Southern Company

Antonio Grayson

No

1) R4 is duplicative of R1 - either remove "maintain" from R1 or delete R4 - both instances of "maintain" are not needed. 2) The measures, as written, provide no additional indication of the evidence that could be presented to demonstrate compliance with the Reliability Standard Requirements. They provide little guidance on assessing non-compliance with the Requirements.

No

See our response to Question 9.

No

All of these comments pertain to FAC-003-3: 1) We suggest referring to the Implementation Plan in the Effective Date sub-section of Section A of the standard rather than repeating the content of the Implementation Plan in the standard. There exists unnecessary duplication with including the information in both places. 2) We suggest simplifying the purpose statement to more succinctly say the intent, for example: "To maintain a reliable transmission system by managing vegetation located on transmission rights of way to minimize vegetation encroachments and thereby minimize the risk of vegetation related outages". If this change is not acceptable, at least change the phrase "preventing the risk" to "minimizing the risk". 3) We feel that the Enforcement paragraphs between 4.3.1.3 and 5.0 seem to be out of place. Those paragraphs don't belong in this location - consider moving them to Section C. Compliance. The fourth paragraph belongs in the background section. 4) We suggest moving the background section to Section F. "Associated Documents". It gets in the way of getting to the requirements of the standard. 5) We suggest moving Table 2 of the "Guideline and Technical Basis" document into R1, since it seems to be the only part of the document that is enforceable. Further we suggest that the Guideline and Technical Basis document be removed from the standard. The inclusion of this document in the standard makes the standard unweildy. 6) We suggest reordering the words in R1 to more clearly state the requirement. Please consider this rephrasing: "For lines which are either an element of an IROL or an element of a Major WECC Transfer Path, each

applicable TO and applicable GO shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) when operating within their Rating during all Rated Electrical Operating Conditions of the types shown below: ..." (remainder is unchanged). 7) We suggest reordering the words of R2 to more clearly state the requirement. Please consider the this rephrasing: "For lines which are neither an element of an IROL nor an element of a Major WECC Transfer Path, each applicable TO and applicable GO shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) when operating within its Rating and during all Rated Electrical Operating Conditions of the types listed below: ..." (remainder is unchanged). 8) On Page 11 of the posted clean draft standard, is the reference to the previous footnote 2 correct? We recommend eliminating footnotes where possible to minimize redirections. 9) The Rationale text-box on page 13 of the clean version of FAC-003-3 overlaps some of the text of footnote #6.

Yes

The development of a working TVMP will take some time to initialize. The 1 year time frame for R3 is appropriate. The 2 year time frame for all other requirements is appropriate.

No

We believe that a standard development process should not have parallel paths where the same version is being modified by multiple teams. The uncertainty in which development path leads to confusion in the industry and ultimately proves to have wasted some resources for the path that does not come to fruition.

Yes

Additional responses are needed to justify the exclusion of the list of requirements and standards found in the recent FERC order denying the rehearing request of the Compliance Registry Appeals of Cedar Creek and Milford. (135 FERC Para. 61,241). Please see our response to Question 10 for a detailed discussion on this topic.

No

We don't believe the effort realizes the goal because 1) it is inclusive of FAC-001 that does not need any modifications and 2) the effort needs to reinforce the appropriate justification not to include the additional standards FERC has identified in their Cedar Creek and Milford Orders.

Yes

The version history table is incorrect - change version 3 to version 2.1.

Yes

Southern does not think that the revision to FAC-001-1 is necessary. A Generator Owner (GO) cannot assess reliability impacts to the Bulk Electric System (BES) and determine acceptability without support and involvement of the applicable owner and operator of the Transmission System (i.e., the "interconnected TO" or "interconnected TP"). A generator tie-line does not equate to a Transmission System. A GO must already adhere to a TO's Facility connection requirements whether the GO wants to connect additional facilities or a third parties' facilities to its own interconnection Facilities. Stated another way, the GO does not need Facility Connection requirements to govern how multiple units are tied to a collector bus so why are they needed for a third party to connect to an existing tie-line? In either case it is the interconnected TO or interconnected TP that has connection requirements that must be fulfilled. The GO's Interconnection Agreement would prohibit it from connecting additional facilities without a new application for Interconnection Service with its interconnected TO or interconnected TP. A GO should not need to develop "connection requirements" unless it is in the business of owning and operating facilities independently of its interconnected TO or interconnected TP. We do not believe a reliability gap exists in FAC-001-1 because the requestor for interconnecting another Facility to an existing generation Facility must coordinate with the applicable TO, TP, and PA in accordance with FAC-002-0 to ensure they meet all applicable facility connection and performance requirements. If and when there is an agreement in place for a third party to connect to a generator tie-line then the tie-line would become part of the integrated system and its purpose and the owner's function would likely warrant registration as a TO/TOP and FAC-001 would then apply. The following excerpt from the 2010-07 Background Resource White Paper acknowledges that this may be necessary: "The drafting team also acknowledges that, if another party interconnects to a Facility owned by a Generator Owner, there may be the need to address MOD or TPL standards. However, the drafting team believes that this, too, is best handled through specific evaluation, perhaps accompanied by changes to the compliance registry. Entities that face this kind of scenario may also meet criteria applicable to other registrations such as Transmission Service Provider or

Transmission Planner.” [Arguments related to jurisdictional, interconnection policy and open access transmission tariff issues] (1) Because of (a) jurisdiction under Section 215, (b) FERC’s interconnection policy, and (c) the requirements of the pro forma open access transmission tariff (OATT), a GO should not be required to comply with FAC-001-1 until that GO’s generating Facility reaches commercial operation. NERC should not make facilities subject to the mandatory reliability standards before the facilities are actually part of the BES. (a) Jurisdiction under FPA Section 215. First, it is not clear that NERC or FERC has jurisdiction under FPA Section 215 to require generation facilities that have not actually reached commercial operation to be subject to reliability standards. Section 215(a)(2) of the FPA defines the “Electric Reliability Organization” as “the organization certified by the Commission ... the purpose of which is to establish and enforce reliability standards for the bulk-power system, subject to Commission review.” Further, (a)(3) provides that “The term ‘reliability standard’ means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system. The term includes requirements for the operation of existing bulk-power system facilities ... the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system ....” Thus, under Section 215 NERC can develop reliability standards that address requirements for existing bulk-power system facilities (i.e., facilities that have reached “commercial operation”) and for the design of planned additions or modifications. It is logical to interpret the phrase “design of new facilities” as meaning that new facilities must be designed to comply with existing reliability standards. However, it is not clear that this provision should be interpreted as requiring that a generating facility that has not yet reached commercial operation should be subject to reliability standards (including audit and penalties). Therefore, the GO with the existing generation facilities should not be required to incorporate the proposed generation facility into its Facility connection requirements before the proposed generation facility is subject to NERC or FERC jurisdiction. (b) FERC’s interconnection policy. In addition, the revised FAC-001 would appear to place restrictions on interconnection customers in contravention of Order Nos. 2003 and 2006 (Standard Large and Small Interconnection Procedures and Agreements). FERC was very concerned about the ability of interconnection customers to interconnect their generating facilities and gave them a fair amount of flexibility. However, this revised FAC-001 would appear to restrict some of this flexibility. (i) Order No. 2003 gives the interconnection customer the ability to terminate a proposed interconnection on ninety days notice. Therefore, the interconnection customer is not required to build the facility. However, this revised FAC-001 appears to assume that the interconnection customer does not have this flexibility. What if the interconnection customer (the GO building a new generator on its site or the third party building a new generation facility) decides to terminate the Large Generator Interconnection Agreement (LGIA) or not proceed with the generation facility? In such event, the GO may be required to revert to its previous Facility connection requirements in order to accommodate the original configuration. (ii) The LGIA permits modifications to the proposed interconnection. How would this affect the Facility connection requirements? How long would the GO have to revise its Facility connection requirements? In the event that there is a single modification, or perhaps multiple modifications, how does the GO stay in compliance with this standard? (iii) FAC-001-1, R4 provides that each GO with Facility connection requirements and each TO shall maintain Facility connection requirements and make documentation of these requirements available to users of the Transmission System upon request. However, Large Generator Interconnection Procedures (LGIP), Section 3.4 requires the posting of certain interconnection information but the identity of the interconnection customer is not to be disclosed (unless it is an Affiliate). Requirement R4 would appear to potentially require disclosure of information and (more importantly) of the interconnection customer’s identity in contravention of the requirements in Order No. 2003 and the LGIP. (c) OATT requirements. The definition of “applicable Generator Owner” (Section 4.2.1) and Requirement R2 provide that the GO will have an executed Agreement to evaluate the impact of interconnecting a new facility to the GO’s existing generation facility. This statement is ambiguous. This statement could be understood to mean that the GO of the existing generation Facility will enter into an Agreement with the GO proposing to interconnect and the existing GO will evaluate the impact of the proposed interconnection. However, requests to interconnect new generation are processed under an OATT. In that case, it would be the Transmission Provider (not the existing GO) that would evaluate the impact of interconnecting the new facility. Thus, the language in FAC-001-1 would need to be revised to clarify that the owner of the new facility will need to interconnect under the OATT of an appropriate Transmission Provider (i.e., the Transmission Provider to which the existing GO is interconnected, not with the existing GO). Therefore, the owner of the new facility will most likely be the entity with the executed Agreement

(with the Transmission Provider). Another consideration is that the existing GO could be developing a merchant transmission line. In that case, the existing GO would need to evaluate whether it needs have its own OATT and OASIS. In that case, the new generator owner would be interconnecting to the existing GO. However, the existing GO's line would not be a generator tie-line. This issue is not clear from the draft standard. (2) The following are suggested changes to FAC-001-1. (a) We recommend the Purpose statement be revised to state, "To avoid adverse impacts on BES reliability..." (b) It is unclear in Applicability section 4.2.1 that the term "Agreement" means that the GO has an executed agreement with a TO/TSP or that the GO and the third party have an executed agreement. Without further explanation, the capitalized term "Agreement" has the effect of introducing confusion. If the SDT does not intend to propose a new addition to the NERC Glossary of Terms, it should use the lower case term, "agreement." With respect to the capitalized term, "Transmission System," the SDT should consider clarifying if it intends to propose adding this to the Glossary. (3) Effect of the proposed revisions to FAC-001-1 on FAC-002-1. (a) As drafted, there are scenarios under which a new GO may attempt to interconnect to an existing GO even though, as explained above, the interconnection should actually be done to the appropriate Transmission Provider. If the appropriate Transmission Provider is not included in the evaluation of the interconnection various types of harm may occur. In such event, the TPs and PAs should be indemnified from any liability with respect to performance of the evaluations required by FAC-002. (b) FAC-001 and FAC-002 should be revised to be clear that the existing GO and any new GOs must coordinate any interconnection with the appropriate Transmission Provider, TP and PA.

We agree with the 2010-17 Standard Drafting Team's conclusion to not modify other standards such as those mentioned on page 4 of the Technical Justification document. In addition, we wish to provide the following support for exclusion of these specific standards. Southern Company believes NERC's Project 2010-07 SDT must challenge making revisions to the standards included in the FERC order on Cedar Creek and Milford. (This order supports NERC's requirement for those entities to register as a TO/TOP due to their ownership of generator interconnection circuits > 100kV.) We believe there are clear technical and reliability-based reasons that support not adding GO and GOP requirements to these standards and not requiring the GO or GOP to register as a TO or TOP. Furthermore, we also believe there are clear distinctions between GO/GOP responsibilities and TO/TOP responsibilities that must be maintained to ensure BES reliability. Revising standards to assign TO/TOP responsibilities to a GO/GOP or requiring a GO/GOP to register as a TO/TOP because of generator interconnection circuits > 100kV will reduce the clarity of these responsibilities. We have provided specific comments on each standard below: EOP-005-1 R1, R2, R6, R7 R1 and R2 require each TOP to have and maintain a system restoration plan. R6 requires the TOP to train its operating personnel in implementing this plan. R7 requires the TOP to verify its restoration plan by actual testing or simulation. These requirements are clearly the role and responsibility of the TOP, not a GO/GOP who happens to have generator interconnection facilities in the TOP's control area. The GOP's roles and responsibilities are clearly and appropriately addressed EOP-005-2. The presence of a generator interconnection circuit > 100kV that happens to be owned by the GO instead of the TOP fundamentally does not change the roles and responsibilities of the TOP or the GOP. Thus, no changes due to EOP-005 are needed. FAC-014-2, R2 FAC-014-2 R2 states "The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology." FAC-014-2 R2 should not be revised to include GOPs. The GO is required by FAC-008-1 R1 and FAC-009-1 (FERC approved version) and pending FAC-008-3 R3 and R6 (FAC-008-3 filed with FERC for approval) to document the Facility Ratings for a GO-owned generator interconnection circuit >100kV. The established Facility Rating must respect the most limiting applicable equipment rating in the circuit and must consider operating limitations and ambient conditions. The thermal or ampere rating of this circuit would equal its ampere operating limit and should be conveyed by the GO to the GOP if they are not the same entity. The operating voltage limits for this circuit are established by the applicable TO/TOP, not the GO or GOP. Therefore, we believe adding the GO to FAC-014-2 R2 would be redundant. PER-003-1 R2, R2.1, R2.2 PER-003-1 R2 and its sub-requirements state: "R2. Each Transmission Operator shall staff its Real-time operating positions performing Transmission Operator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates (1) : [Risk Factor: High][Time Horizon: Real-time Operations]: R2.1. Areas of Competency R2.1.1. Transmission operations R2.1.2. Emergency preparedness and operations R2.1.3. System operations R2.1.4. Protection and control R2.1.5. Voltage and reactive R2.2. Certificates • Reliability Operator • Balancing, Interchange and Transmission Operator •

Transmission Operator This requirement is specifically for TOPs. Personnel training for GOPs needs to be addressed separately and not mingled with responsibilities of the TOP. The GOPs role in supporting BES reliability needs to be clearly understood and defined prior to establishing training requirements in the standards. PRC-001-1, R2, R2.2, R4, R6 Generator Operators (GOPs) and the scope of protection equipment for generation interconnection Facilities are already appropriately accounted for in this standard in requirement R2 and sub-requirement R2.2 The language used in requirement R2 which applies to the GOP uses the general terms "relay or equipment failures" which would include not only generator relaying, but generator interconnection relaying in the GOPs scope as well. The GOP is required to notify the TOP and Host BA in R2.1 "if a protective relay or equipment failure reduces system reliability." Requirement R2.2 requires the affected TOP to notify its RC and affected TOPs and BAs. Thus, applying R2.2 to a GOP would be redundant to R2.1. Requirement R4 states, "Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities." A generator interconnection tie line does not constitute a "major tie line" or major "interconnection with neighboring GOPs, TOPs, and BAs." Thus, R4 should not be revised to include GOPs. If a GO exists within NERC that does own such interconnection facilities, the responsibility for coordination of protection systems on such a line or interconnection should be the responsibility of the TOP in that area, not the GO/GOP. This may require formal agreements between the TO/TOP and GO/GOP, since the GO may own protection equipment on his end. The same logic applies to R6. R6 states, "Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status." This is clearly the responsibility of the TOP and/or BA, not a GO/GOP who happens to have generator interconnection facilities in the area. An SPS function by definition is to maintain BES reliability. If a GO/GOP has equipment within the equipment scope of a Special Protection System (SPS), responsibility for monitoring the SPS should be conveyed in a formal agreement as appropriate. TOP-001-1 R1 Requirement R1 states, "Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies." This is clearly the responsibility of the TOP, not a GO/GOP who happens to have generator interconnection facilities in the TOP's area. Thus, R1 should not be applied to a GO/GOP who owns or operates generator interconnection facilities. Furthermore, TOP-001-1 R3 (proposed to be covered in the future in the proposed IRO-001-2 R2 and R3) appropriately requires the GOP to comply with reliability directives issued by the TO "unless such actions would violate safety, equipment, regulatory or statutory requirements." These requirements effectively give the TOP the necessary decision-making authority over operation of all generator Facilities up to the point of interconnection. They also give the GOP the necessary authority to take appropriate actions to ensure safety and protection of the GO's equipment. Thus, no changes to TOP-001-1 are necessary. TOP-004-2 R6, R6.1, R6.2, R6.3, R6.4 Requirement R6 and its sub-requirements state: "R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: R6.1. Monitoring and controlling voltage levels and real and reactive power flows. R6.2. Switching transmission elements. R6.3. Planned outages of transmission elements. R6.4. Responding to IROL and SOL violations." These are clearly the responsibility of the TOP, not a GO/GOP who happens to have generator interconnection facilities in the TOP's area. Thus, these requirements should not be applied to a GO/GOP who owns or operates generator interconnection facilities. The same logic applies here as stated above in our discussion on TOP-001-1. We believe it is inappropriate and would be adverse to BES reliability to apply these requirements to a GOP. TOP-004-2 effectively gives the TOP the necessary decision-making authority over operation of all generator Facilities up to the point of interconnection. They also give the GOP the necessary authority to take appropriate actions to ensure safety and protection of the GO's equipment, such as opening high voltage generator output breakers when required to protect the unit. Thus, no changes to TOP-004-2 are necessary. TOP-006-2 R3 Requirement R3 states, "R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel. The intent of this requirement when applied to a GOP is already addressed in PRC-001-1 R1 which states, "Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area." Thus, no change to TOP-006-2 is necessary.

Group
ACES Power Marketing Standards Collaborators
Jason Marshall
Yes
We largely agree with the changes the drafting team made but believe some additional changes are necessary. In section 4.2.1 of the Applicability Section, "within" should be "with". Because NERC's Glossary of Terms establishes that an Agreement can be verbal and not enforceable by law, section 4.2.1 should be further modified to clarify that it is a legally enforceable and fully executed Agreement. The language in R3 in parenthesis after Generation Owner should be modified to "once required by Requirement R2". This makes it clearer that R3 does not apply until the GO has an executed Agreement to evaluate a request by a third part to interconnect.
Yes
Yes
We support the changes to FAC-003 suggested by the drafting team because we believe the drafting team has provided the best solution in face of a difficult problem. However, in general, we do not support registration of GOs and GOPs as TOs and TOPs or applicability of any TO/TOP requirements to the GO/GOP simply because they have a radial interconnection greater than one mile in length. While there may be some generators that own interconnecting facilities of significant length operated at a significant voltage that could impact BES reliability, we do not believe that the number of generating facilities that fit into that category is significantly large. When one considers that the majority of generators are still owned and operator by utilities that are also registered as a TO and TOP, there is only a minority subset of generators left that could be considered. NERC has the registration for this remaining set of generators and could use the data to evaluate how many of this remaining subset have interconnections owned by the generator that are substantial enough to affect reliability. It seems that NERC could determine the boundaries of this problem before registering anymore GOs and GOPs as TOs and TOPs or before applying additional requirements through this effort on the GOs and GOPs.
Yes
Yes
With recent NERC BOT approval of the FAC-003-2 standard, the drafting team should continue to monitor the standard progress with FERC and make necessary adjustments to the implementation plan.
Yes
Yes
No
The modifications are largely the appropriate ones with the exceptions we noted in Q1 and Q10.
The modifications to PRC-004-2.1 R2 could be interpreted as requiring the GO to analyze Protection System Misoperations on the generator interconnection Facility even if it does not own the Facility. We suggest modifying the requirement as shown below to address this issue. "The Generator Owner shall analyze Protection System Misoperations on its generator and generator interconnection Facility that it owns ..."
Group
Western Electricity Coordinating Council
Steve Rueckert

No
WECC casts an affirmative vote for the SDT proposal as a necessary but not sufficient step in addressing the GOTO matter. WECC, NERC, and the other Regions developed a subset of Standards and Requirements that were considered necessary to address potential gaps for transmission interconnection facilities and operations to be included in a proposed NERC Directive, which is expected to issue by year-end. The subset of requirements developed for the proposed NERC Directive were informed by the applicable FERC Orders. Consequently, it is important that the SDT address the comparative reliability risks between the proposed NERC Directive List and the SDT Proposal to assure that reliability gaps will not result from the SDT proposal. Please see NERC's proposed Directive for the rationale and technical justification.
Please see response to question #7.

See additional comments received attached.

## Additional Comments Received

### Generator Requirements at the Transmission Interface (Project 2010-07)

#### NERC Comments:

1. Based on stakeholder comment, the SDT clarified the applicability language of FAC-001-1 and removed the Generator Owner from R4. Do you support the proposed redline changes to FAC-001-1? (Please refer to the posted FAC-001-1 technical justification document for more information about the SDT's rationale for its changes.)

Yes

No

Comments:

2. Do you support the one year compliance timeframe for Generator Owners as proposed in the Implementation Plan for FAC-001-1?

Yes

No

Comments: There appears to be no rationale for allowing one year for the development of connection requirements given the Technical Justification rationale that the compliance clock starts "if and only if when it executes an Agreement to evaluate....", recognizing the time lag indicated in the Technical Justification.

3. With respect to FAC-003, many commenters focused on the half-mile qualifier in FAC-003. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: "...that extends greater than one mile beyond the fenced area of the generating station switchyard..." We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.

Taking into consideration that only one of the versions of FAC-003 will actually be implemented, a decision that will be made as Project 2007-07—Vegetation Management moves forward, do you support the proposed redline changes to FAC-003-X and FAC-003-3?

Yes

No

Comments:

4. Do you support compliance timeframe for Generator Owners as included and explained in the Implementation Plans for FAC-003-X?

Yes



No

Comments:

5. In the FAC-003-3 implementation plan, the SDT has attempted to account for a number of different scenarios that could play out with respect to the filing and approvals of FAC-003-2 and FAC-003-3. Do you support this approach? If there are other scenarios that the SDT needs to account for, please suggest them here.

Yes

No

Comments:

6. In its technical justification document, the SDT reviews all standards that had been proposed for substantive modification in the Ad Hoc Group's original support and explains why, with the exception of FAC-003, modifying them would not provide any reliability benefit. Do you support these justifications? If you believe the SDT needs to add more information to its rationale for any of these decisions, please include suggested language here.

Yes

No

Comments: Please see the comments to Question 7 for the rationale for expanding the scope of the SDT to address additional Standards.

7. The SDT is attempting to modify a set of standards so that radial generator interconnection Facilities are appropriately accounted for in NERC's Reliability Standards, both to close reliability gaps and to prevent the unnecessary registration of GOs and GOPs at TOs and TOPs. Does the set of standards currently posted achieve this goal?

Yes

No

Comments:

Regarding Project 2010-07 Generator Requirements at the Transmission Interface, NERC staff advises the SDT revisions to the following Standards must be included, for all facilities that are deemed to be 'BES Transmission Facilities more commonly described as Generator Leads':

a) EOP-005-1 R1, R2, R5, R6 and R7

Revisions to this Standard are needed to respond to:

- If GOP has blackstart resources defined by its RC, then EOP-005 applies. The GOP restoration plan would require coordination with TOP per the TOP Blackstart Restoration Plan. The GOP would start its blackstart resources to provide necessary real and reactive power to its generating resources per interconnecting TOP directives. (Note: In addition, if GOP has blackstart capability the interconnection TOP will have included this capability in its restoration planning for its area of responsibility.)

- If GOP does not have blackstart resources, GOP restoration plan is dependent upon provision of real and reactive power service from interconnecting TOP, per VAR-001 and VAR-002 requiring the GOP to follow the directives of the interconnecting TOP, compliance with this standard/requirements is not required.

b) FAC-014-2 R2

If the Transmission system has associated SOLs as directed by its RC, the applicable GOP shall establish these limits per the RC's direction

c) PER-002-0

In order that the requirements of PER-003-0 are not applied, PER-002 should be revised to require the applicable GOP should develop an appropriate training program that contains the necessary elements for the GOP operating their Transmission facility to understand fully the impacts of operation on the BES; such as a) equipment involved, including protection systems, b) the coordination aspects with the TO/TOP to which it is connected, and c) the protocols for and impacts of operating facilities associated with a Transmission facility. The objective of this training is to ensure that the GOP is completely aware of its obligations to have the ability to follow the directives of the appropriate TOP. This ability includes personnel with the skills and training to execute these obligations in the best interest of reliability concerning the reliable operational and coordination issues with the interconnecting TOP.

Therefore, for all generators that are determined to be a typical Generator Long Lead type facility, revising PER-002 would provide a method that recognizes full NERC Certification of operators at these type generators is unnecessary to bridge the reliability gap that exists until all appropriate Reliability Standards are revised to incorporate the proper wording. The basis of this conclusion is through a rudimentary technical evaluation of the topics required for full NERC Certified Operator initial certification. This review resulted in only 25% of the topics included in the certification testing requirements would generally apply to operators at a typical Generator Long Lead type facility. Consequently, revising PER-002 would provide adequate training that will meet the facts and circumstances of each specific generator and as such bridges the reliability gap.

A component of this training might be NERC Technical Reference Document '*Power Plant and Transmission System Protection Coordination*'.

(<http://www.nerc.com/docs/pc/spctf/Gen%20Prot%20Coord%20Rev1%20Final%2007-30-2010.pdf>)

- d) PRC-001 In order to avoid confusion, revise R1 to require the applicable GO to maintain, and the applicable GOP, to monitor those systems defined as BES Transmission metering and protection circuits/systems above and beyond the Generation equipment metering and protection circuits/systems; and R4 to coordinate Transmission protection systems with the interconnection TOP's protection system that apply.

- e) PRC-005 In order to avoid confusion, revise the Standard R1 to require the applicable GO to develop a program which includes those maintenance and testing intervals and a summary of procedures for those systems defined as BES Transmission metering and protection circuits/systems above and beyond the Generation metering and protection circuits/systems.
- f) TOP-001-1 R1 Applicable GOPs assigned to operate their BES Transmission facilities have clear and unambiguous authority to operate those facilities.
- g) TOP-004-2 R6 Applicable GOPs to develop formal policies and procedures that provide for coordination of activities associated with their Transmission facilities that may impact reliability with their interconnecting TOP and/or GOPs identified in FAC-001
- h) TOP-006-1 R3 Applicable GOPs provide appropriate technical information concerning Transmission metering and protection circuits/systems to their operating personnel.

8. If you answered "yes" to Question 7, are the modifications the SDT has made in this posting the appropriate ones?

Yes

No

Comments: See full comments in Question 7

9. If you answered "no" to Question 7, what standards need to be added or removed to achieve the SDT's goal? Please provide technical justification for your answer.

Yes

No

Comments: See full comments in Question 7 and also refer to question 6 and the reference to the Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface, dated Nov 16, 2009

10. Do you have any other comments that you have not yet addressed? If yes, please explain.

Yes

No

Comments:

Notwithstanding the comments in the SDT's Technical Justification paper relative to work within other existing or future Standard Development Projects, we advise this SDT to expand its scope to include the above listed necessary Standards revisions.

# Consideration of Comments

## Generator Requirements at the Transmission Interface Project 2010-07

The Generator Requirements at the Transmission Interface Drafting Team thanks all commenters who submitted comments for Project 2010-07—Generator Requirements at the Transmission Interface. These standards were posted for a 45-day public comment period from October 5, 2011 through November 18, 2011. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 40 sets of comments, including comments from 123 different people from approximately 86 companies representing all 10 of the Industry Segments as shown in the table on the following pages.

Based on stakeholder comments, the SDT made minor changes to FAC-001-1, FAC-003-X, FAC-003-3, and PRC-004-2.1. The standards will proceed to recirculation ballot.

In FAC-001-1, the SDT corrected a typo in the Applicability section 4.2.1 to change “within” to “with”; corrected a typo in the VSLs for R3 to ensure that parts 3.1.1 through 3.1.16 were referenced, rather than just 3.1.1 through 3.1.6; and changed references to “Transmission System” to “interconnected Transmission systems” to ensure consistency with the language elsewhere in the standard and in FAC-002-1.

In FAC-003-X and FAC-003-3, the SDT added a clarifying reference to line of sight in the GO exemption in section 4.3.1. of both versions; corrected a typo in 4.3.1.2 of FAC-003-3; and changed “RE” to “Regional Entity” in 4.3.1 of FAC-003-X.

As it discusses in the document titled “[Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface](#),” the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.

To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: “Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”

With this reference, the SDT simply seeks to clarify the exception language based on the intent that has been agreed upon by the stakeholder body. In its [Consideration of Comments report](#) from the last formal comment period, which ended on July 17, 2011, the SDT explained “We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor.” With the addition of an explicit line of sight reference here, the SDT believes it has clarified its original intent and appropriately considered all comments submitted.

Members of the ballot pool should note that for its recirculation ballot, the SDT will be balloting **both** FAC-003-3 and FAC-003-X, but stakeholders should **not** vote as though they are choosing one or the other. The SDT plans to present FAC-003-3 alone to NERC’s Board of Trustees, but it wants to have FAC-003-X ready to submit to the Board if, for some reason, neither FAC-003-2 nor FAC-003-3 are approved by FERC. Members of the ballot body should vote on the merits of each version of FAC-003 individually. **In other words, stakeholders who support adding GOs to the applicability of FAC-003 should vote in the affirmative for both FAC-003-3 and FAC-003-X.**

In PRC-004-2.1, the SDT added a reference to the generator interconnection Facility to the data retention section of the standard (for consistency with the language in R2) and corrected a typo in the Version History.

Several commenters pointed out that the wording in R1 and R2 of PRC-005-1a requires the same explicit reference to a generator interconnection Facility that was added in PRC-004-2.1 R2. The SDT agrees and is developing revisions to PRC-005-1a. These will be posted (separate from the recirculation ballot posting) soon.

Many commenters encouraged the SDT to reexamine the standards and requirements addressed in FERC’s Milford and Cedar Creek orders and NERC staff’s draft compliance directive regarding generator lead lines. The NERC [Standard Processes Manual](#) does not address the issue of how to deal with FERC Orders (that don’t include explicit directives), or draft NERC directives, within the standards process, and until this round of comments, when NERC staff submitted comments, the SDT had no formal mandate that would have made it appropriate to consider the content of the proposed directive.

The SDT reviewed all addressed standards and requirements again and continues to find clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards and not requiring the GO or GOP to register as a TO or TOP. However, to address stakeholder concern, the SDT has expanded its technical justification document (posted under “Supporting Materials”) to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive.

Other minority comments are addressed within specific questions below.

All comments submitted may be reviewed in their original format on the standard's project page:

[http://www.nerc.com/filez/standards/Project2010-07\\_GOTO\\_Project.html](http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html)

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 404-446-2560 or at [herb.schrayshuen@nerc.net](mailto:herb.schrayshuen@nerc.net). In addition, there is a NERC Reliability Standards Appeals Process.<sup>1</sup>

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<sup>1</sup> The appeals process is in the Standard Processes Manual: [http://www.nerc.com/files/Appendix\\_3A\\_Standard\\_Processes\\_Manual\\_20110825.pdf](http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf).

**Index to Questions, Comments, and Responses**

1. Based on stakeholder comment, the SDT clarified the applicability language of FAC-001-1 and removed the Generator Owner from R4. Do you support the proposed redline changes to FAC-001-1? (Please refer to the posted FAC-001-1 technical justification document for more information about the SDT’s rationale for its changes.) ..... 12

2. Do you support the one year compliance timeframe for Generator Owners as proposed in the Implementation Plan for FAC-001-1? ..... 29

3. With respect to FAC-003, many commenters focused on the half-mile qualifier in FAC-003. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: “...that extends greater than one mile beyond the fenced area of the generating station switchyard...” We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.

Taking into consideration that only one of the versions of FAC-003 will actually be implemented, a decision that will be made as Project 2007-07—Vegetation Management moves forward, do you support the proposed redline changes to FAC-003-X and FAC-003-3? ..... 34

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5. In the FAC-003-3 implementation plan, the SDT has attempted to account for a number of different scenarios that could play out with respect to the filing and approvals of FAC-003-2 and FAC-003-3. Do you support this approach? If there are other scenarios that the SDT needs to account for, please suggest them here. .... 57

6. In its technical justification document, the SDT reviews all standards that had been proposed for substantive modification in the Ad Hoc Group’s original support and explains why, with the exception of FAC-003, modifying them would not provide any reliability benefit. Do you support these justifications? If you believe the SDT needs to add more information to its rationale for any of these decisions, please include suggested language here. .... 63

7. The SDT is attempting to modify a set of standards so that radial generator interconnection Facilities are appropriately accounted for in NERC’s Reliability Standards, both to close reliability

- gaps and to prevent the unnecessary registration of GOs and GOPs at TOs and TOPs. Does the set of standards currently posted achieve this goal? ..... 74
- 8. If you answered “yes” to Question 7, are the modifications the SDT has made in this posting the appropriate ones? ..... 87
- 9. If you answered “no” to Question 7, what standards need to be added or removed to achieve the SDT’s goal? Please provide technical justification for your answer. .... 91
- 10. Do you have any other comments that you have not yet addressed? If yes, please explain. .... 99



**The Industry Segments are:**

- 1 — Transmission Owners
- 2 — RTOs, ISOs
- 3 — Load-serving Entities
- 4 — Transmission-dependent Utilities
- 5 — Electric Generators
- 6 — Electricity Brokers, Aggregators, and Marketers
- 7 — Large Electricity End Users
- 8 — Small Electricity End Users
- 9 — Federal, State, Provincial Regulatory or other Government Entities
- 10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment										
				1	2	3	4	5	6	7	8	9	10	
1.	Group	Gerald Beckerle	SERC OC Standards Review Group	X		X								
1.	Scott Brame	NCEMC	SERC 1, 3, 4, 5											
2.	Troy Willis	Georgia Transmission Corp.	SERC 1											
3.	Mike Hirst	Cogentrix	SERC 5											
4.	Bob Dalrymple	TVA	SERC 1, 3, 5, 6											
5.	Matt Carden	Southern Co.	SERC 1, 5											
6.	Shardra Scott	Gulf Power Co.	SERC 3											
7.	Kerry Sibley	Georgia Transmission Corp.	SERC 1											
8.	Andy Burch	EEL	SERC 5											
9.	Shaun Anders	City of Springfield (CWLP)	SERC 1, 3											
10.	Melinda Montgomery	Entergy	SERC 1, 3, 5											
11.	John Troha	SERC Reliability Corp	SERC 10											
2.	Group	Jonathan Hayes	Southwest Power Pool Standards Development Team		X									
<b>Additional Member</b>		<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>										

Group/Individual	Commenter	Organization	Registered Ballot Body Segment																
			1	2	3	4	5	6	7	8	9	10							
1. Jonathan Hayes	Southwest Power Pool	SPP	2																
2. Robert Rhodes	Southwest Power Pool	SPP	2																
3. Don Taylor	Westar	SPP	1, 3, 5, 6																
4. John Allen	City Utilities of Springfield	SPP	1, 4																
5. Sean Simpson	MCPBPU	SPP	1, 3, 5																
6. Louis Guidry	CLECO	SPP	1, 3, 5																
7. Mitch Williams	Western Farmers	SPP	1, 3, 5																
8. Valerie Pinnamonti	AEP	SPP	1, 3, 5																
9. Bud Averill	Grand River Dam Authority	SPP	1, 3, 5																
10. Terri Pyle	OGE	SPP	1, 3, 5																
3.	Group	Guy Zito, Guy Zito	Northeast Power Coordinating Council, Northeast Power Coordinating Council																X
	<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>															
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC, NPCC	10															
2.	Greg Campoli	New York Independent System Operator	NPCC, NPCC	2															
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC, NPCC	1															
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC, NPCC	1															
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC, NPCC	10															
6.	Brian Evans-Mongeon	Utility Services	NPCC, NPCC	8															
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC, NPCC	5															
8.	Kathleen Goodman	ISO - New England	NPCC, NPCC	2															
9.	Chantel Haswell	FPL Group, Inc.	NPCC, NPCC	5															
10.	David Kiguel	Hydro One Networks Inc.	NPCC, NPCC	1															
11.	Michael R. Lombardi	Northeast Utilities	NPCC, NPCC	1															
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC, NPCC	9															
13.	Bruce Metruck	New York Power Authority	NPCC, NPCC	6															
14.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC, NPCC	10															
15.	Robert Pellegrini	The United Illuminating Company	NPCC, NPCC	1															
16.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC, NPCC	1															
17.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC, NPCC	5															
18.	Saurabh Saksena	National Grid	NPCC, NPCC	1															
19.	Michael Schiavone	National Grid	NPCC, NPCC	1															

Group/Individual	Commenter	Organization	Registered Ballot Body Segment											
			1	2	3	4	5	6	7	8	9	10		
20. Wayne Sipperly	New York Power Authority	NPCC, NPCC 5												
21. Tina Teng	Independent Electricity System Operator	NPCC, NPCC 2												
22. Donald Weaver	New Brunswick System Operator	NPCC, NPCC 2												
23. Ben Wu	Orange and Rockland Utilities	NPCC, NPCC 1												
24. Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC, NPCC 3												
4. Group	Emily Pannel	Southwest Power Pool Regional Entity												X
No additional members listed.														
5. Group	Will SMith	MRO NSRF	X	X	X	X	X	X	X	X				X
<b>Additional Member Additional Organization Region Segment Selection</b>														
1. Mahmood Safi	OPPD	MRO	1, 3, 5, 6											
2. Chuck Lawrence	ATC	MRO	1											
3. Jodi Jenson	WAPA	MRO	1, 6											
4. Ken Goldsmith	ALTW	MRO	4											
5. Alice Ireland	XCEL/NSP	MRO	1, 3, 5, 6											
6. Dave Rudolph	BEPC	MRO	1, 3, 5, 6											
7. Eric Ruskamp	LES	MRO	1, 3, 5, 6											
8. Joe DePoorter	MGE	MRO	3, 4, 5, 6											
9. Scott Nickels	RPU	MRO	4											
10. Terry Harbour	MEC	MRO	1, 3, 5, 6											
11. Marie Knox	MISO	MRO	2											
12. Lee Kittelson	OTP	MRO	1, 3, 4, 5											
13. Scott Bos	MPW	MRO	1, 3, 5, 6											
14. Tony Eddleman	NPPD	MRO	1, 3, 5											
15. Mike Brytowski	GRE	MRO	1, 3, 5, 6											
16. Richard Burt	MPC	MRO	1, 3, 5, 6											
6. Group	Charles W. Long	SERC Planning Standards Subcommittee	X											X
<b>Additional Member Additional Organization Region Segment Selection</b>														
1. Pat Huntley	SERC	SERC	10											
2. John Sullivan	Ameren Services Co.	SERC	1											
3. Philip Kleckley	SC Electric & Gas Co.	SERC	1											
4. Bob Jones	Southern Company Services	SERC	1											

Group/Individual	Commenter	Organization	Registered Ballot Body Segment												
			1	2	3	4	5	6	7	8	9	10			
5. Jason Adams	TVA	SERC 1													
7. Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X							
<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>												
1. Timothy Beyrle	City of New Smyrna Beach	FRCC	4												
2. Greg Woessner	Kissimmee Utility Authority	FRCC	3												
3. Jim Howard	Lakeland Electric	FRCC	3												
4. Lynne Mila	City of Clewiston	FRCC	3												
5. Joe Stonecipher	Beaches Energy Services	FRCC	1												
6. Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4												
7. Randy Hahn	Ocala Utility Services	FRCC	3												
8. Group	Mike Garton	Dominion	X		X		X	X							
<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>												
1. Michael Gildea	Dominion Resources Services, Inc.	RFC	5, 6												
2. Connie Lowe	Dominion Resources Services, Inc.	NPCC	5, 6												
3. Michael Crowley	Virginia Electric and Power Company	RFC	1, 3												
9. Group	Annette M. Bannon	PPL NERC Registered Affiliates			X		X	X							
<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>												
1. Brent Ingebrigston	LG&E and KU Services Co.	SERC	3												
2. Don Lock	PPL Brunner Island, LLC	RFC	5												
3.	PPL Martins Creek, LLC	RFC	5												
4.	PPL Holtwood, LLC	RFC	5												
5.	PPL Montour, LLC	RFC	5												
6.	Lower Mount Bethel Energy, LLC	RFC	5												
7. Annete Bannon	PPL Susquehanna, LLC	RFC	5												
8. Leland McMillan	PPL Montana, LLC	WECC	5												
10. Group	Jason Marshall	ACES Power Marketing Standards Collaborators													
<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>												
1. Mohan Sachdeva	Buckeye Power	RFC	3, 5, 6												
2. Erin Woods	East Kentucky Power Cooperative	SERC	1, 3, 5, 6												
3. Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6												

Group/Individual		Commenter	Organization	Registered Ballot Body Segment											
				1	2	3	4	5	6	7	8	9	10		
11.	Group	Steve Rueckert	Western Electricity Coordinating Council												X
No additional members listed.															
12.	Individual	Jack Cashin	Electric Power Supply Association					X	X						
13.	Individual	Natalie McIntire	American Wind Energy Association					X							
14.	Individual	Tom Flynn	Puget Sound Energy, Inc.	X				X	X						
15.	Individual	Silvia Parada Mitchell	Compliance & Responsibility Organization	X		X		X	X						
16.	Individual	Antonio Grayson	Southern Company	X		X		X	X						
17.	Individual	Chris Higgins/Stephen Enyeart/Chuck Mathews/Charles Sheppard	Bonneville Power Administration	X		X		X	X						
18.	Individual	Thad Ness	American Electric Power	X		X		X	X						
19.	Individual	Carla Bayer	BP Wind Energy North America Inc.					X							
20.	Individual	John Bee on behalf of Exelon	Exelon	X				X							
21.	Individual	Dennis Sismaet	Seattle City Light	X		X	X	X	X						
22.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP (Occidental Chemical)					X							
23.	Individual	Michael Falvo	Independent Electricity System Operator		X										
24.	Individual	Greg Rowland	Duke Energy	X		X		X	X						
25.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X											
26.	Individual	Kirit Shah	Ameren	X		X		X	X						
27.	Individual	John Seelke	PSEG	X		X		X	X						
28.	Individual	Andrew Z. Pusztai	American Transmission Company	X											
29.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X						
30.	Individual	Ravi Bantu	RES Americas Development					X							
31.	Individual	Katy Wilson	Sempra Generation					X							

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
32.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
33.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
34.	Individual	Ed Davis	Entergy Services	X		X		X	X				
35.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
36.	Individual	Russell A. Noble	Cowlitz County PUD			X	X	X					
37.	Individual	Anthony Jablonski	ReliabiltyFirst										X
38.	Individual	Donald Jones	Texas Reliability Entity										X
39.	Individual	Amir Hammad	Constellation Power Source Generation					X					
40.	Individual	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

1. **Based on stakeholder comment, the SDT clarified the applicability language of FAC-001-1 and removed the Generator Owner from R4. Do you support the proposed redline changes to FAC-001-1? (Please refer to the posted FAC-001-1 technical justification document for more information about the SDT’s rationale for its changes.)**

#### Summary Consideration:

The SDT thanks all stakeholders for their comments and their 87% approval for the FAC-001-1 changes posted for ballot in November 2011. Based on stakeholder feedback, the SDT has made the following minor changes to FAC-001-1:

-Corrected a typo in Applicability section 4.2.1 to change “within” to “with.”

-Corrected a typo in the VSLs for R3 to ensure that parts 3.1.1 through 3.1.16 were referenced, rather than just 3.1.1 through 3.1.6.

-Changed references to “Transmission System” to “interconnected Transmission systems” to ensure consistency with the language elsewhere in the standard and in FAC-002-1.

Some stakeholders remain concerned about the intent of the SDT’s work on FAC-001-1. The SDT reminded them that the scope is addressed in the SAR. The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT determined that it should first address “low-hanging fruit” and believes these to be sole-use Facilities (see posted examples under “Supporting Materials”) – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP). Through its deliberations, the SDT concluded that an interconnection Facility owned or operated by a GO or GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT.

Concerned commenters were also referred to one of the SDT’s resource documents: [Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document](#).

Some commenters suggested changes to Requirements R1 or R4, which deal exclusively with the Transmission Operator and are outside the scope of the SDT’s work.

One commenter suggested formatting changes. The SDT agrees with the commenter that there are a number of ways to format the standard with this SDT’s revisions. However, the majority of stakeholders support the current format of the standard and no change was made.

One commenter suggested that the phrase “Generator Owner’s existing Facility” be changed to “Generator Owner’s existing Transmission Facility.” The SDT does not agree with labeling a GO’s Facility as “Transmission,” in part because in

some areas (like Texas), GOs, by statute, can't own Transmission. It was also brought to the SDT's attention that in most cases, the Facility in question is referred to as the Interconnection Facility in documents filed by the GO with FERC. Therefore, the SDT intentionally modified language so that a Facility owned by a generation entity did not contain the term "Transmission."

One commenter did not agree with the overall clarifying change to the Applicability section, but the SDT reminded this commenter that this change was made to address previous comments that indicated that there was uncertainty as to whether "another Facility to its existing generation Facility" was meant to address connecting additional generators by the same GO. The SDT intends FAC-001-1 to apply only when the GO of an existing Facility executes an agreement to evaluate the reliability impact of connecting additional generation owned by another GO. No change made with respect to this comment.

A few stakeholders were concerned with the 45-day time frame included in the standard. The SDT pointed out that majority of stakeholders and the SDT support 45 days as a sufficient time frame because in many cases, the GO would simply need to adopt (document and publish) the Facility connection requirements of its TO. No change to that time frame was made.

Organization	Yes or No	Question 1 Comment
Manitoba Hydro	Negative	The intention of the NERC SDT in revising these standards is not clear. While the Technical Justification document states that the SDT intended to focus on a Generator Owner's radial interconnection facilities, the scope of the revised standard (s) is not confined to such facilities. The very broadly defined term "Facility" is used. Moreover, the Technical Justification document's reference to the FERC decision in Cedar Creek as a basis for the revision of additional standards is confusing, since that decision did not specifically address the issue of radial facilities and supported NERC's registration of GOs as TOs.
<p><b>Response:</b> Thank you for your comment. The scope of this SDT is addressed in the <a href="#">SAR</a>. The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT determined that it should first address "low-hanging fruit" and believes these to be sole-use Facilities (see posted examples under "Supporting Materials") – that is, a Facility used to connect one or more generators to a Facility owned or operated by a</p>		



Organization	Yes or No	Question 1 Comment
<p>transmission entity (TO/TOP). Through our deliberations, we came to the conclusion that an interconnection Facility owned or operated by a GO or GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT.</p> <p>The SDT also refers the commenter to the document titled <a href="#">Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document</a>. Specifically, see the last paragraph on page 4 and first two on page 5.</p>		
Southern Company	No	<p>1) R4 is duplicative of R1 - either remove "maintain" from R1 or delete R4 - both instances of "maintain" are not needed.â€¢ 2) The measures, as written, provide no additional indication of the evidence that could be presented to demonstrate compliance with the Reliability Standard Requirements. They provide little guidance on assessing non-compliance with the Requirements. â€¢</p>
<p><b>Response:</b> Thank you for your comment. We agree with your suggestions, but both are outside the scope of this SDT. These items will be submitted to the Issues Database to be addressed in a future revision of FAC-001.</p>		
Southwest Power Pool Standards Development Team	No	<p>Based on the applicability section of FAC-001 we feel that the strike through should have been kept. It limited the requirement to just those generator owners who had agreements in place, which we feel is appropriate.</p>
<p><b>Response:</b> Thank you for your comment. This change was made to address previous comments that indicated to the SDT there was uncertainty as to whether this was meant to address connecting additional generators by the same GO. The SDT intends FAC-001 to apply only when the GO of an existing Facility executes an agreement to evaluate the reliability impact of connecting additional generation owned by another GO. No change made with respect to this comment.</p>		
Texas Reliability Entity	No	<p>In Section 5.1, the reference to Regional Entity should be removed. There are no requirements that apply to the Regional Entity.</p> <p>In Requirements R1 and R4, "Planning Coordinator" should be added after "Regional Entity." In the ERCOT Region it is the Planning Coordinator that maintains planning criteria and connection requirements. There is no NERC</p>

Organization	Yes or No	Question 1 Comment
		<p>requirement or any obligation (as indicated in the technical justification document) on the part of a GO to specifically execute an Agreement to evaluate the reliability impact of interconnecting a third party Facility. Therefore, this requirement’s applicability is contingent on a prerequisite that may not occur, and that is under the control of the GO. This assumption on the part of the SDT unnecessarily complicates the compliance monitoring and enforcement of this standard. For instance, if an “Agreement” is not executed, a GO is not required to comply with the requirement, even though the GO may ultimately interconnect with another entity. The requirement should be modified to include an applicability trigger similar to that of FAC-002-1, so that once a GO “seek[s] to integrate . . .,” i.e., agrees to or is compelled to allow a third-party interconnection, then the requirement becomes applicable. Otherwise, the compliance and monitoring is subject to the SDT’s speculation as indicated in this language included in the technical justification document: “However, the SDT cannot be certain this is the only example and it therefore proposes to add this new requirement to FAC-001-1. In doing so, the SDT acknowledges that the Generator Owner may not, at the time it agrees or is compelled to allow a third party to interconnect, have the necessary expertise to conduct the required interconnect studies to meet this standard. Assuming that a regulatory body would require a Generator Owner to evaluate such an interconnection request, the SDT expects the Generator Owner and the third party to execute some form of an Agreement.”</p>
<p><b>Response:</b> Thank you for your comment. All of these comments are outside the scope of the <a href="#">SAR</a> and the SDT’s work because they refer specifically to the sections and requirements that apply to the TO alone. We encourage you to consider submitting a SAR that addresses your concerns.</p>		
Manitoba Hydro	No	<p>Manitoba Hydro has the following comments:</p> <ol style="list-style-type: none"> <li>1) The intention of the NERC SDT in revising these standards is not clear.</li> </ol>

Organization	Yes or No	Question 1 Comment
		<p>While the Technical Justification document states that the SDT intended to focus on a Generator Owner’s radial interconnection facilities, the scope of the revised standard (s) is not confined to such facilities. The very broadly defined term “Facility” is used. Moreover, the Technical Justification document’s reference to the FERC decision in Cedar Creek as a basis for the revision of additional standards is confusing, since that decision did not specifically address the issue of radial facilities and supported NERC’s registration of GOs as TOs.</p> <p>2) If the drafting team intends to limit the scope of FAC-001-1 to GO owned radial generator interconnection facilities that are not deemed BES transmission and therefore would not require the registration of the GO as a TO, Manitoba Hydro disagrees with the proposed changes to FAC-001-1 as Generator Owners may not have the models or expertise to perform interconnection studies to determine if there is an impact on the Transmission Network. This concern is echoed in the technical justification document provided by NERC: ‘the SDT acknowledges that the Generator Owner may not, at the time it agrees or is compelled to allow a third part to interconnect, have the necessary expertise to conduct the required interconnect studies to meet this standard... the Generator Owner will have to acquire such expertise. How the Generator Owner chooses to do so is not for the SDT to determine.’ Although it may not be for the SDT to determine how a GO obtains technical expertise, ensuring that such expertise is acquired before a GO conducts the required interconnection studies should be a concern to NERC as this directly affects the reliability of the BES. As a result, all interconnection requests should be implemented by the TO providing the GO with connection to the BES regardless if the interconnection point is within a Generation Owner facility or End-User facility as the TO is in the best position to set unbiased connection requirements to ensure the reliability of the BES is maintained. If the scope of FAC-001-1 also applies to GO owned BES transmission facilities, Manitoba</p>

Organization	Yes or No	Question 1 Comment
		<p>Hydro strongly believes that the Compliance Registry should apply and the GOs should be required to register as a TO and abide by all applicable standards to that functional type. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. Reliability gaps would be better addressed if select GOs and GOPs registered as TOs and TOPs to ensure all reliability standards, including the protection standards, are met so the reliability of the BES is maintained. At this time, this would not lead to a large number of extra registrations since, as stated in the technical justification document, ‘interconnection requests for Generator Owner Facilities are still relatively rare.</p> <p>3) If the redline changes are implemented, GOs are removed from R4, thereby removing the obligation for GOs to maintain their connection requirements. If GOs are included in FAC-001, they should be held accountable to the same level as TOs and should be required to maintain their connection requirements. Requiring a GO to maintain connection requirements would be especially beneficial to the GO themselves. In the majority of instances, any GO that is an Applicable Entity for FAC-001 would initially be inexperienced in performing interconnection studies and would benefit from regular and frequent review of their connection requirements as experience and expertise are gained.</p> <p>4) The revision to FAC-001-1 R2 may be problematic, depending on what was intended. Under the revised requirement, the obligation to comply is dependent on the execution of an agreement to evaluate reliability impacts under FAC-002-1. However, FAC-002-1 does not clearly require the execution of an agreement by the Generator Owner. FAC-002-1 only requires the Generator Owner to “coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority”. Accordingly if a Generator Owner coordinates without executing an agreement to perform an assessment, compliance with FAC-001 R1 will not</p>

Organization	Yes or No	Question 1 Comment
		<p>be required.</p> <p>5) Manitoba Hydro would also like to point out that if the redline changes are implemented, it will greatly increase the complexity of coordination required under FAC-002-1 for Transmission Planners/Planning Authorities.</p>
<p><b>Response:</b> Thank you for your comment. The scope of this SDT is addressed in the <a href="#">SAR</a>. The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP).</p> <p>The intent of the modifications to this standard is to address the requirements of the GO prior to the interconnection of the third party to their Facilities. The reliability gap the SDT intends to close is the need for the GO to develop Facility connection requirements prior to interconnection. The SDT does agree that upon interconnection of a third party, other standards or registrations may apply as appropriate.</p> <p>The SDT also refers the commenter to the document titled <a href="#">Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document</a>, which is posted on the project page. Specifically, see the last paragraph on page 4 and first two on page 5.</p>		
Tennessee Valley Authority	No	<p>Suggest that the overall structure of the standard be revised such that R1 - R3 are applicable to the Transmission Owner (consistent with existing FAC-001-0) and R4 (the new requirement) is applicable to the “applicable Generator Owner”. See further comments below. Support the proposed revisions to R1 and R4, but suggest R4 be returned to R3 (consistent with existing FAC-001-0).R3 in the balloted standard should be returned to R2 (consistent with existing FAC-001-0) and only be applicable to the Transmission Owner. R3.1 (or R2.1 if moved back) should be “fixed”, but it may be beyond this SDT’s charge. The use of “above” in the FAC-001-0 standard, or the proposed reference to “Requirements R1 or R2” in the proposed standard do not make sense in combination with the colon used at the end of the requirement. Suggest that R3.1 (or 2.1 if moved back) be revised as written below and all sub-requirements of R3.1 be elevated (R3.1.1 becomes R3.2, R3.1.2 becomes R3.3, etc.).”R3.1 Performance</p>

Organization	Yes or No	Question 1 Comment
		<p>requirements and/or planning criteria used to assess system impacts.” R2 in the balloted standard should become R4 and modified to incorporate the connection requirements contained in R3 that can more reasonably be expected of an “applicable Generator Owner”. For instance, an “applicable Generator Owner” might simply have a connection requirement for a third party that addresses coordination of system impact studies with the appropriate Transmission Owner(s), in lieu of R3.1, R3.1.1, and R3.1.2. Suggest that R2 (or R4 if moved below existing FAC-001-0 requirements) be revised as written below.”R2 Each applicable Generator Owner that has agreed to allow a third party Facility owner (Generation Facility, Transmission Facility, or End-user Facility) to connect to the Transmission system through use of pre-existing applicable Generator Owner Facilities shall communicate it’s Facility connection requirements to the third party. The applicable Generator Owner Facility connection requirements shall address the following items: R2.1 Coordination of system impact studies with the Transmission Owner. R2.2 Voltage level and MW and MVAR capacity or demand at point of connection. R2.3 Breaker duty and surge protection. R2.4 System protection and coordination R2.5 Metering....” Etc.</p>
<p><b>Response:</b> Thank you for your comment. We gave the comment due consideration and agree that there are a number of ways to format the standard with this SDT’s revisions. However, the majority of stakeholders support the current format of the standard. No change made.</p>		
<p>Northeast Power Coordinating Council, Northeast Power Coordinating Council</p>	<p>No</p>	<p>The intent of the draft language in FAC-001-1 is to provide guidance for addressing the alleged reliability gap that exists between GO/GOPs that own/ operate transmission facilities but are not registered as TO/TOPs. The impact of the revised language will depend on the characterization of the generator lead after the “third party “ connects to the existing generator lead. IF the generator lead is owned by the TO utility after the third party connection : The proposed DRAFT FAC-001 language suggests that within 45 days of a 3rd party having an executed Agreement to evaluate the reliability</p>

Organization	Yes or No	Question 1 Comment
		<p>impact of interconnecting, the existing generator needs to document and publish facility connection requirements. The proposed language suggests that a third party can commandeer existing generators leads and interconnect. A reclassification would be required because “third party” power would flow through the downstream portions of the existing leads. This introduces significant challenges for defining ownership / transfer of installed assets as well as real property, easements, operational jurisdiction, O&amp;M cost responsibility, etc. The FERC approved pro-forma Attachment X Interconnection Agreement clearly states that the project Developer must meet all Applicable Reliability Standards which means that all requirements and guidelines of the Applicable Reliability Councils, and the Transmission District to which the Developer’s Large Generating Facility is directly interconnected. As an example, to accommodate this NERC proposal, the FERC approved NYISO pro-forma tariff would need to be revised to allow this “third party” use. The pro-forma interconnection tariff also states that the Developer must provide updated project information prior to the Facilities Study. The Facilities Study might not be made until several years after the Interconnection Request /Feasibility Study is made (“executed Agreement to evaluate the reliability impact of interconnecting” in this proposed draft is akin to the Interconnection Request/Feasibility Study). Placing the requirement to have the existing Generator Owner publish reliability requirements for a potential “third party user”, without the generator having any knowledge of the potential reliability outcomes or asset transfer / ownership issues is not a reasonable expectation. The interconnection of a third party to an existing generator lead would force existing generators to revise their Interconnection Agreements with FERC. The “third party”, would at a minimum, need to comply with the existing Generators reliability obligations as specified in the Interconnection Agreement. IF the third party connects to the GO owned generator lead, the GO will be considered a TO:A TO would not be involved, other than review</p>

Organization	Yes or No	Question 1 Comment
		<p>of the SRIS and Facilities reports. The difficult thing for an existing GO would be to prepare, within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility, a document listing the requirements. To allow for the above possibilities, the language for applicability of FAC-001 to GO’s or GOP’s, should be :”Each applicable Generator Owner shall, at least 60 days prior to execution of a Facilities / Class Year Study Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the Transmission System, document and publish its Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, sub regional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements.”</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees with many of the comments (as indicated in the accompanying resource document titled <a href="#">Technical Justification: FAC-001-1</a>), especially those concerning the complexities of this process. The majority of stakeholders and the SDT support 45 days as a sufficient time frame because in many cases, the GO would simply need to adopt (document and publish) the facility connection requirements of its TO. No change made.</p>		
<p>Consolidated Edison Co. of NY, Inc.</p>	<p>No</p>	<p>The language for FAC-001 Requirement R2 should be:”This requirement shall apply to each applicable Generator Owner. Generator Owner filings must be made at least 60 days in advance of execution of the final interconnection study agreement in the Planning Coordinator’s or Transmission Planner’s study process.Each applicable Generation Owner must publish its Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, sub regional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements.The evaluation of the reliability impact(s) of interconnecting a third party Facility to the Generator Owner’s existing Facility utilized for interconnection to the Transmission System must be</p>



Organization	Yes or No	Question 1 Comment
		documented.”
<p><b>Response:</b> Thank you for your comment. The SDT agrees with many of the comments (as indicated in the accompanying resource document titled <a href="#">Technical Justification: FAC-001-1</a>), especially those concerning the complexities of this process. The majority of stakeholders and the SDT support 45 days as a sufficient time frame because in many cases, the GO would simply need to adopt (document and publish) the facility connection requirements of its TO. No change made.</p>		
<p>Ingleside Cogeneration LP (Occidental Chemical)</p>	<p>No</p>	<p>Unfortunately, the vital point of this requirement revolves around whether or not a Generator Owner is compelled externally to allow access to their interconnection facilities. If the GO is driving the connection for financial or other business reasons, there is no reason they should not be responsible for developing AND maintaining a facility connection requirements document. Otherwise, when the local transmission system requirements change for any reason, there will be no entity responsible to ensure that the third party will conform as well. Conversely, if the GO should be compelled to allow access to a third party, it is the responsibility of the “compeller” to handle all the related reliability studies and documents. This may include the development of a CFR which separates reliability tasks between the GO and other entities - especially if a TSP registration is required. This ensures that the Regional Entity, PUC, RTO, or other regulator must budget dollars and resources directly related to their action - not cause them to be directed to a GO.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees with many of the comments (as indicated in the accompanying resource document titled <a href="#">Technical Justification: FAC-001-1</a>), especially those concerning the complexities of this process. However, the issues you raise are beyond the scope of the SDT and its SAR. No change made.</p>		
<p>PSEG</p>	<p>No</p>	<p>We revised this partial sentence to the following: “Each applicable Generator Owner shall, within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Transmission Facility that is used for connection</p>

Organization	Yes or No	Question 1 Comment
		<p>to the interconnected Transmission systems (under FAC-002-1), ..."- The phrase "Generator Owner's existing Facility that is used to interconnect to the Transmission System" was changed to "Generator Owner's existing Transmission Facility that is used for connection to the interconnected Transmission systems." - "Transmission" was added before Facility to exclude connections elsewhere; "Transmission System" was changed to "Transmission systems" because while "Transmission" and "System" are defined in the NERC Glossary, "System" means "A combination of generation, transmission, and distribution components." "Transmission systems" do not have generation or distribution components, so a lower case "system" is warranted. - In addition, the suggested phrase "interconnected Transmission systems" (plural "systems") uses identical language from FAC-002-1, except that we capitalized "Transmission.</p>
<p><b>Response:</b> Thank you for your comment. The SDT has addressed the proposed change to applicability according to your comments. The applicability section now reads: "Generator Owner with an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems.</p> <p>The SDT has been informed that in some areas (like Texas), GOs, by statute, can't own Transmission. It was also brought to the SDT's attention that in most cases, the Facility in question is referred to as the Interconnection Facility in documents filed by the GO with FERC. Therefore, the SDT intentionally modified language so that a Facility owned by a generation entity did not contain the term "Transmission."</p>		
Seattle City Light	Affirmative	Key points are that (1) an executed agreement is required before evaluations of impacts are necessary and (2) this only applies when a third party is connecting to the generating interconnection line.
<p><b>Response:</b> Thank you for your comment.</p>		
Electric Power Supply Association	Yes	All TO requirements for FAC-001-1 would apply if and when GO executes an Agreement to evaluate the reliability impact of interconnecting a third

Organization	Yes or No	Question 1 Comment
		<p>party Facility to its existing generation interconnection Facility. The execution of the agreement is necessary to comply with FAC-002-1 and start the compliance clock with the applicable regulatory authority. Thus as the Project 2010-07 Standard Drafting Team (SDT) in its technical justification has stated, “If, and only if, the existing owner of a generator interconnection Facility has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to its existing generation Facility” then FAC-001-1 should apply. EPSA concurs with SDT’s conclusion. The SDT has examined the issue regarding if future requests for transmission service on the interconnection Facility and in doing so acknowledged that when that Facility adopted open access and was providing transmission service it would necessitate re-evaluation of the need for the Facility to be maintained in accordance with FAC-001-1, Requirements 2 and 4. This service would indeed prompt the necessary agreement the SDT contemplates in its technical justification of FAC-001-1. EPSA believes this serves as the necessary trigger for evaluation of Requirements 2 and 4 under FAC-001-1 for GOs.</p>
<p><b>Response:</b> Thank you for your comment.</p>		
<p>American Wind Energy Association</p>	<p>Yes</p>	<p>AWEA appreciates that this standard specifies that it has limited applicability. For instance, only those generators that have an executed agreement with a third party wishing to interconnect must document and publish Facility connection requirements. We believe the proposed 45-day time window is a minimum for GO/GOP owners of generator lead lines to provide this documentation following execution of such an agreement. Anything less than 45 days could result in a burdensome and hard to meet deadline for GO/GOP staff. However, AWEA believes that extending this time window for publishing Facility connection requirements to 90 days after an executed agreement would be beneficial. We believe this will allow the GO/GOP owners of generator leads more time to coordinate with their</p>

Organization	Yes or No	Question 1 Comment
		interconnecting Transmission Providers and will result in more reliable and coordinated connection requirements for the generator lead.
<p><b>Response:</b> Thank you for your comment. The majority of stakeholders and the SDT support 45 days as a sufficient time frame because in many cases, the GO would simply need to adopt (document and publish) the facility connection requirements of its TO. No change made.</p>		
SERC OC Standards Review Group	Yes	Please verify within the applicability section (4.2.1) you intended to use the word “within” rather than some other wording.
<p><b>Response:</b> Thank you for your comment. The SDT intended it to read “Generator Owner <b>with</b> an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the Transmission System.” This change has been made.</p>		
RES Americas Development	Yes	RES Americas and AWEA appreciate that this standard specifies that it has limited applicability. For instance, only those generators that have an executed agreement with a third party wishing to interconnect must document and publish Facility connection requirements. We believe the proposed 45-day time window is a minimum for GO/GOP owners of generator lead lines to provide this documentation following execution of such an agreement. Anything less than 45 days could result in a burdensome and hard to meet deadline for GO/GOP staff. However, we believes that extending this time window for publishing Facility connection requirements to 90 days after an executed agreement would be beneficial. We believe this will allow the GO/GOP owners of generator leads more time to coordinate with their interconnecting Transmission Providers and will result in more reliable and coordinated connection requirements for the generator lead.
<p><b>Response:</b> Thank you for your comment. The majority of stakeholders and the SDT support 45 days as a sufficient time frame because in many cases, the GO would simply need to adopt (document and publish) the facility connection requirements of its TO</p>		

Organization	Yes or No	Question 1 Comment
No change made.		
ACES Power Marketing Standards Collaborators	Yes	We largely agree with the changes the drafting team made but believe some additional changes are necessary. In section 4.2.1 of the Applicability Section, “within” should be “with”. Because NERC’s Glossary of Terms establishes that an Agreement can be verbal and not enforceable by law, section 4.2.1 should be further modified to clarify that it is a legally enforceable and fully executed Agreement. The language in R3 in parenthesis after Generation Owner should be modified to “once required by Requirement R2”. This makes it clearer that R3 does not apply until the GO has an executed Agreement to evaluate a request by a third part to interconnect.
<p><b>Response:</b> Thank you for your comment. We agree that “within” should be “with”. The SDT chose not to adopt the second recommendation as the requirement already contains the term “executed.” The SDT also chose not to adopt the third recommendation as the requirement already contains the parenthetical (in accordance with Requirement R2) which we feel is synonymous with the comment.</p>		
Southwest Power Pool Regional Entity	Yes	
MRO NSRF	Yes	
SERC Planning Standards Subcommittee	Yes	
Florida Municipal Power Agency	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	

Organization	Yes or No	Question 1 Comment
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Exelon	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
Ameren	Yes	
American Transmission Company	Yes	
South Carolina Electric and Gas	Yes	
Sempra Generation	Yes	
Xcel Energy	Yes	
Cowlitz County PUD	Yes	
Constellation Power Source Generation	Yes	
ReliabilityFirst		
Entergy Services		

Organization	Yes or No	Question 1 Comment
Western Electricity Coordinating Council		
Puget Sound Energy, Inc.		
Compliance & Responsibility Organization		
Bonneville Power Administration		

**2. Do you support the one year compliance timeframe for Generator Owners as proposed in the Implementation Plan for FAC-001-1?**

**Summary Consideration:**

The vast majority of commenters supported the one year compliance time frame in the Implementation Plan. A few commenters were concerned with this time frame and associated enforcement, in part based on similar issues addressed in recent CANs. The SDT did its best to clarify its intent as follows:

The SDT’s intent is that the mandatory date (the date upon which the GO must be compliant with applicable requirements and measures) be the first calendar day of the first calendar quarter one year after FAC-001-1’s approval. The SDT believes one year is sufficient time for the GO to become compliant where it has one or more in-place (which we interpret as synonymous with legacy or grandfathered) executed Agreement(s). If an Agreement is executed after the mandatory date, then the GO has 45 days to “document and publish its Facility connection requirements” (R2) and those requirements shall address items under R3.

No changes were made to the Implementation Plan.

Organization	Yes or No	Question 2 Comment
Ingleside Cogeneration LP (Occidental Chemical)	No	Based upon similar issues addressed in Compliance Application Notices (CANs), the drafting team needs to specify how the requirements apply to an in-place “executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the Transmission System.” In the view of Ingleside Cogeneration LP, if the Agreement takes effect even one day before FAC-001-1 does, requirements R2 and R3 do not apply. Without this clarification, it is possible that NERC’s Compliance team will apply the requirements retroactively - with minimum industry input.
<p><b>Response:</b> Thank you for your comment. The SDT’s intent is that the mandatory date (the date upon which the GO must be compliant with applicable requirements and measures) be the first calendar day of the first calendar quarter <u>one year after its approval</u>. The SDT believes one year is sufficient time for the GO to become compliant where it has one or more in-place (which we interpret as synonymous with legacy or grandfathered) executed Agreement(s). If an Agreement is executed after the mandatory date, then the GO has 45 days to “document and publish its Facility connection requirements” (R2) and those requirements shall</p>		



Organization	Yes or No	Question 2 Comment
address items under R3.		
Southwest Power Pool Regional Entity	No	No action is required unless a GO has an executed third-party agreement. If a GO has an agreement, the standard already includes a 45-day timeframe for the GO to document and publish its facility connection requirements.
<p><b>Response:</b> Thank you for your comment. The SDT’s intent is that the mandatory date (the date upon which the GO must be compliant with applicable requirements and measures) be the first calendar day of the first calendar quarter <u>one year after its approval</u>. The SDT believes one year is sufficient time for the GO to become compliant where it has one or more in-place (which we interpret as synonymous with legacy or grandfathered) executed Agreement(s). If an Agreement is executed after the mandatory date, then the GO has 45 days to “document and publish its Facility connection requirements” (R2) and those requirements shall address items under R3.</p>		
Southern Company	No	See our response to Question 9.
<p><b>Response:</b> See the SDT’s response to Question 9.</p>		
Manitoba Hydro	No	See question 1 comments.
<p><b>Response:</b> See SDT’s response to Question 1.</p>		
Cowlitz County PUD	Yes	Cowlitz PUD (District) registered as a Transmission Owner shortly before FAC-001-0 became effective and was forced to file a Mitigation Plan in order to facilitate compliance. The District successfully completed compliance implementation and documentation in eight months. The proposed one year compliance timeframe is sufficient.
<p><b>Response:</b> Thank you for your comment and support.</p>		
Seattle City Light	Yes	The proposed changes for FAC-001-1 state a 45 day period to complete the evaluation. Not sure what the question is referring to regarding “ 1 year “?

Organization	Yes or No	Question 2 Comment
<p><b>Response:</b> Thank you for your comment. The SDT’s intent is that the mandatory date (the date upon which the GO must be compliant with applicable requirements and measures) be the first calendar day of the first calendar quarter <u>one year after its approval</u>. The SDT believes one year is sufficient time for the GO to become compliant where it has one or more in-place (which we interpret as synonymous with legacy or grandfathered) executed Agreement(s). If an Agreement is executed after the mandatory date, then the GO has 45 days to “document and publish its Facility connection requirements” (R2) and those requirements shall address items under R3.</p>		
<p>American Wind Energy Association / RES Americas Development</p>	<p>Yes</p>	<p>Yes, since there is no exigent reason why this standard needs to be put in place at once, we support the one-year compliance timeframe. We believe that it will allow generators a reasonable time to comply with the requirement.</p>
<p><b>Response:</b> Thank you for your comment and support.</p>		
<p>SERC OC Standards Review Group</p>	<p>Yes</p>	
<p>Southwest Power Pool Standards Development Team</p>	<p>Yes</p>	
<p>Northeast Power Coordinating Council, Northeast Power Coordinating Council</p>	<p>Yes</p>	
<p>MRO NSRF</p>	<p>Yes</p>	
<p>SERC Planning Standards Subcommittee</p>	<p>Yes</p>	
<p>Florida Municipal Power Agency</p>	<p>Yes</p>	

Organization	Yes or No	Question 2 Comment
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Electric Power Supply Association	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Exelon	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
Ameren	Yes	
PSEG	Yes	
American Transmission Company	Yes	

Organization	Yes or No	Question 2 Comment
South Carolina Electric and Gas	Yes	
Sempra Generation	Yes	
Xcel Energy	Yes	
Constellation Power Source Generation	Yes	
Western Electricity Coordinating Council		
Puget Sound Energy, Inc.		
Compliance & Responsibility Organization		
Bonneville Power Administration		
Consolidated Edison Co. of NY, Inc.		
Entergy Services		
ReliabilityFirst		
Texas Reliability Entity		

3. With respect to FAC-003, many commenters focused on the half-mile qualifier in FAC-003. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: “...that extends greater than one mile beyond the fenced area of the generating station switchyard...” We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.

Taking into consideration that only one of the versions of FAC-003 will actually be implemented, a decision that will be made as Project 2007-07—Vegetation Management moves forward, do you support the proposed redline changes to FAC-003-X and FAC-003-3?

#### Summary Consideration:

The SDT thanks all stakeholders for their comments and their over 85% approval for the FAC-003-X and FAC-003-3 changes posted for ballot in November 2011. Based on stakeholder feedback, the SDT has made the following changes:

- Added a clarifying reference to line of sight in the GO exemption in section 4.3.1.
- Corrected a typo in 4.3.1.2 of FAC-003-3.
- Changed “RE” to “Regional Entity” in 4.3.1 of FAC-003-X.

As it discusses in the document titled “[Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface](#),” the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.

To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: “Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”

With this reference, the SDT simply seeks to clarify the exception language based on the intent that has been agreed upon by the stakeholder body. In its [Consideration of Comments report](#) from the last formal comment period, which ended on July 17, 2011, the SDT explained “We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor.” With the addition of an explicit line of sight reference here, the SDT believes it has clarified its original intent and appropriately considered all comments submitted.

Some stakeholders suggested changes that should have been submitted when Project 2007-07 was revising FAC-003-2, because these suggestions dealt with the standard as a whole rather than the changes made by this SDT to ensure that GOs are included in the standard’s applicability.

One commenter remains concerned about the scope of the SDT. The SDT reminded this commenter that its scope is addressed in the [SAR](#) and that its intent is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT also refers the commenter to the document titled [Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document](#). Specifically, see the last paragraph on page 4 and first two on page 5.

Organization	Yes or No	Question 3 Comment
Ameren Services	Negative	<p>(a) There is no technical basis for the one mile length exemption. In fact, one could argue that a very short line, 300 feet in length, that experienced a fault from a tree at "the end of the circuit", i.e near the switchyard fence, would have much more of an impact on the BES because the fault would be limited by much less impedance.</p> <p>(b) It is also unclear in this version if a GO that owned one line that was 1.2 miles in length would have to comply for the entire length of said line, or just 0.2 miles of said line. If the GO is responsible for 1.2 miles, then that argues that the first mile is important and consequently there is no basis for ignoring the first mile on other lines. If the GO is only responsible for 0.2 miles, what is the technical basis to ignore a mile? And would it be the first mile from the switchyard that is ignored, or is the middle mile, or the last mile where it connects to the TO? Or could the GO decide? Or could the GO pick sections of the line that amount to a mile that they can ignore? This seems like something that should be addressed for compliance.</p>

Organization	Yes or No	Question 3 Comment
		<p>(c) The 2 year compliance time line is far too long. There is significant industry evidence that was developed in the drafting of Version 2 that supports a one year compliance time-line for new lines. This is evidenced in Version 2. Thus there is no basis for the 2 years</p>
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled "<a href="#">Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface</a>," the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: "Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are..."</p> <p>With respect to your second comment, the SDT intended for the length qualifier to be just that; if the overhead portion of a Facility exceeds the distance, <u>the entire Facility</u> is subject to the requirements of the standard.</p> <p>The SDT chose the time in the implementation plan based upon reasons it documented in the <a href="#">accompanying implementation plan</a> and also based upon comments of stakeholders.</p>		
<p>Wisconsin Public Service Corp Electric Cooperative</p>	<p>Negative</p>	<p>R1.2 refers to an encroachment due to a fall in. This is confusing because according to the dictionary "Webster's II" encroachment reads: "to intrude gradually", and a 'fall in' is not usually gradual.</p>
<p><b>Response:</b> Thank you for your comment. This is outside the scope of the <a href="#">SAR</a>. The SDT reviewed comments submitted as part of the <a href="#">Project 2007-07</a> effort and did not find this comment had been submitted.</p>		
<p>Wisconsin Public Service Corp.</p>	<p>Negative</p>	<p>The concern with the proposed wording is that many generating station may not have a "generating station switchyard" as implied by the proposed wording. Often the generator leads (e.g. 20 kV) will exit the generator and connect to transformers located in transformer bays directly adjacent to the plant. From the transformers the now greater than 200 kV lines will be routed to the point of interconnect or a</p>

Organization	Yes or No	Question 3 Comment
		<p>generating unit switchyard, possibly miles or yards away. By no one’s definitions would the transformer bays adjacent to the plant be considered a switchyard. The plant fence may be yards or hundreds of yards from the bays and on a multiple unit site, there may be a site fence or boundary, which could be comprise of fences, security patrols, or other barriers yards or miles from the transformer but enveloping the switchyard. The valid assumption made by the drafting team is that transmission lines within an area tightly controlled by the generator operator poses very little risk to the BES as a result of vegetation contact. This assumption is based on the valid observation that these areas are routinely occupied and observed by station personnel and as a result unexpected and unacceptable vegetation growth is highly unlikely because it is controlled by routine maintenance. It also correctly assumes that some distance past the controlled area is acceptable since this area would also be under near continuous observation. The problem comes in defining both a tightly controlled area and a line of site. We suggest the following: Controlled Area: A perimeter around a power plant, power plants, or switchyard which is prevents intrusion by the use of physical barriers, observation, or electronic monitoring and is routinely occupied such that unexpected and unacceptable vegetation growth would be observed and correct as a matter of routine maintenance. Line of Sight: A two kilometer distance from the controlled area perimeter.</p>
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled <a href="#">“Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface,”</a> the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: “Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”</p>		
Florida Reliability	Negative	There is no technical justification for excluding 1 mile beyond the fence in the



Organization	Yes or No	Question 3 Comment
Coordinating Council		applicability of generators.
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled "<a href="#">Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface</a>," the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: "Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are..."</p>		
Southern Company	No	<p>â€¢All of these comments pertain to FAC-003-3:</p> <ol style="list-style-type: none"> <li>1) We suggest referring to the Implementation Plan in the Effective Date sub-section of Section A of the standard rather than repeating the content of the Implementation Plan in the standard. There exists unnecessary duplication with including the information in both places.</li> <li>2) We suggest simplifying the purpose statement to more succinctly say the intent, for example: "To maintain a reliable transmission system by managing vegetation located on transmission rights of way to minimize vegetation encroachments and thereby minimize the risk of vegetation related outages". If this change is not acceptable, at least change the phrase "preventing the risk" to "minimizing the risk".</li> <li>3) We feel that the Enforcement paragraphs between 4.3.1.3 and 5.0 seem to be out of place. Those paragraphs don't belong in this location - consider moving them to Section C. Compliance. The fourth paragraph belongs in the background section.</li> <li>4) We suggest moving the background section to Section F. "Associated Documents". It gets in the way of getting to the requirements of the standard.</li> <li>5) We suggest moving Table 2 of the "Guideline and Technical Basis" document into R1, since it seems to be the only part of the document that is enforceable. Further</li> </ol>

Organization	Yes or No	Question 3 Comment
		<p>we suggest that the Guideline and Technical Basis document be removed from the standard. The inclusion of this document in the standard makes the standard unwieldy.</p> <p>6) We suggest reordering the words in R1 to more clearly state the requirement. Please consider this rephrasing: "For lines which are either an element of an IROL or an element of a Major WECC Transfer Path, each applicable TO and applicable GO shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) when operating within their Rating during all Rated Electrical Operating Conditions of the types shown below:..." (remainder is unchanged).</p> <p>7) We suggest reordering the words of R2 to more clearly state the requirement. Please consider the this rephrasing: "For lines which are neither an element of an IROL nor an element of a Major WECC Transfer Path, each applicable TO and applicable GO shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) when operating within its Rating and during all Rated Electrical Operating Conditions of the types listed below:..." (remainder is unchanged).</p> <p>8) On Page 11 of the posted clean draft standard, is the reference to the previous footnote 2 correct? We recommend eliminating footnotes where possible to minimize redirections.</p> <p>9) The Rationale text-box on page 13 of the clean version of FAC-003-3 overlaps some of the text of footnote #6.   â€€,â€€,â€€,</p>
<p><b>Response:</b> Thank you for your comment.</p> <p>With respect to your suggestion regarding the implementation plan, the SDT simply followed the NERC-mandated document guidelines. Making the change you suggest would deviate from that process and thus the SDT has not made it.</p> <p>With respect to comments 2-8, any standard changes that go beyond making a standard applicable to a GO or GOP are beyond the scope of this SDT. Any redline changes the SDT has made within standards were made to clarify or qualify the GO or GOP applicability. These comments would have been more appropriate to make during the comment period for Project 2007-07 Vegetation Management, the project that revised the version of FAC-003 from which this SDT is working.</p>		

Organization	Yes or No	Question 3 Comment
We have modified the rationale box on page 13 so that it does not overlap with the text of footnote 6.		
Dominion	No	<p>Dominion suggests in FAC-003-X; 4.3.1. Regional Entity be changed to RE as listed in 4.2.1 for consistency. Also Regional Entity is used throughout the rest of the document, suggest using RE for consistency overall. Dominion suggests in FAC-003-3; 4.3.1. adding station to the following “ Overhead transmission lines that extend greater than one mile or 1.609 kilometers beyond the fenced area of the generation station switchyard and are” to show consistency as it is written in FAC-003-X 4.3.1. Further, Dominion is concerned that the technical justification characterized the exclusion (i.e., one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard) as “approximate line of sign [sic] from a fixed point” and notes that this line of sight may be limited by local terrain. Where line of sight of the radial corridor is limited on a clear day due to terrain, the one mile exemption must be limited in distance to no more than the line of sight on a clear day beyond the fenced area.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees with your comment about the Regional Entity, but will instead use Regional Entity throughout.</p> <p>Thank you for your comment. As it discusses in the document titled <a href="#">“Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface,”</a> the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: “Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”</p>		
Exelon	No	FAC-003 - Exelon supports the one mile length qualifier, but feels that additional clarification is needed to determine the points of demarcation. There are too many differing physical configurations to use a “fence line” as a determination of

Organization	Yes or No	Question 3 Comment
		<p>applicability. Suggest that the tie line length be defined as “from the Generator Step up Transformer GSU to the point of interconnection between the GO and TO owned equipment.” Also suggest that the standard define what constitutes a generation station switchyard.</p>
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled <a href="#">“Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface,”</a> the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: “Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”</p>		
<p>Ingleside Cogeneration LP (Occidental Chemical)</p>	<p>No</p>	<p>Ingleside Cogeneration LP is very concerned that the attempt to develop “bright-line” criteria to assign applicability to either version of FAC-003 is misplaced. As seen with NERC’s recent proposed directive related to Generator-Transmission interconnections, those thresholds can be arbitrarily reduced based upon regulators aversion to risk - not scientific evidence. (As it stands today, NERC has proposed any interconnection facility operating at 100 kV or higher and greater than 3 spans in length be applicable - which is even stricter than the TO thresholds in FAC-003.) This would suggest that a reliability assessment consistent with the TPL standards must be the determining factor. If the Planning Coordinator or Transmission Planner can show that the Generator-Transmission interconnection could contribute to a violation of an SOL or IROL, then a vegetation management program may be in order. Furthermore, there needs to be some level of common sense applied if a GO-TO interconnection is located in an area where vegetation clearance is never an issue. A one-size-fits-all requirement based upon vegetation growth in the sub-tropics, should not automatically apply in the desert. In our view, every dollar spent to control vegetation in an arid climate is one less dollar available to purchase</p>

Organization	Yes or No	Question 3 Comment
		advanced telemetry, AGC systems, and other items which have a far greater impact on reliability.
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled <a href="#">“Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface,”</a> the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: “Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”</p> <p>The SDT also took into consideration the stakeholder comments submitted and believes this exemption adequately addresses the reliability impact for a majority of the Facilities, while balancing the efforts necessary to support the standard from all entities.</p>		
Manitoba Hydro	No	Manitoba Hydro does not support the changes being proposed in this project. If a Generator Owner is required to register as a TO, all the Requirements applicable to a TO should apply. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions.
<p><b>Response:</b> Thank you for your comment. The scope of this SDT is addressed in the <a href="#">SAR</a>. The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT also refers the commenter to the document titled <a href="#">Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document</a>. Specifically, see the last paragraph on page 4 and first two on page 5.</p>		
Northeast Power Coordinating Council, Northeast Power Coordinating Council	No	Suggest in FAC-003-X; 4.3.1. that Regional Entity be changed to RE as listed in 4.2.1 for consistency. Also Regional Entity is used throughout the rest of the document, suggest using RE for consistency. In FAC-003-3; 4.3.1. add station to the following: “Overhead transmission lines that extend greater than one mile or 1.609 kilometers beyond the fenced area of the generation station switchyard and are” to show consistency as it is written in FAC-003-X 4.3.1. The technical justification characterized the exclusion (i.e., one mile or 1.609 kilometers beyond the fenced

Organization	Yes or No	Question 3 Comment
		<p>area of the generating station switchyard) as “approximate line of sight [sic] from a fixed point” and noted that this line of sight may be limited by local terrain. Where line of sight of the radial corridor is limited on a clear day due to terrain, the one mile exemption must be limited in distance to no more than the line of sight on a clear day beyond the fenced area.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees with your comment about the Regional Entity, but will instead use Regional Entity throughout.</p> <p>Thank you for your comment. As it discusses in the document titled <a href="#">“Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface,”</a> the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: “Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”</p>		
MRO NSRF	No	<p>The NSRF agrees with the drafting committees desire to eliminate arbitrary and capricious behavior of auditors and industry staff by precisely defining the point at which measurement starts for the length of transmission line. The concern the NSRF has with the proposed wording is that many generating station may not have a “generating station switchyard” as implied by the proposed wording. Often the generator leads (e.g. 20 kV) will exit the generator and connect to transformers located in transformer bays directly adjacent to the plant. From the transformers the now greater than 200 kV lines will be routed to the point of interconnect or a generating unit switchyard, possibly miles or yards away. By no one’s definitions would the transformer bays adjacent to the plant be considered a switchyard. The plant fence may be yards or hundreds of yards from the bays and on a multiple unit site, there may be a site fence or boundary, which could be comprise of fences, security patrols, or other barriers yards or miles from the transformer but enveloping</p>

Organization	Yes or No	Question 3 Comment
		<p>the switchyard. The valid assumption made by the drafting team is that transmission lines within an area tightly controlled by the generator operator poses very little risk to the BES as a result of vegetation contact. This assumption is based on the valid observation that these areas are routinely occupied and observed by station personnel and as a result unexpected and unacceptable vegetation growth is highly unlikely because it is controlled by routine maintenance. It also correctly assumes that some distance past the controlled area is acceptable since this area would also be under near continuous observation. The problem comes in defining both a tightly controlled area and a line of site. We suggest the following: Controlled Area: A perimeter around a power plant, power plants, or switchyard which is prevents intrusion by the use of physical barriers, observation, or electronic monitoring and is routinely occupied such that unexpected and unacceptable vegetation growth would be observed and correct as a matter of routine maintenance. Line of Sight: NSRF recommends a two kilometer distance from the controlled area perimeter. Our assessment is that an individual of average height would have a line of site of approximately 4 Kilometers. Therefore, we recommended a distance of 2 kilometers from the Controlled Area of the plant to provide margin. The revised applicability statement would read as follows: “Generator Owner that owns an overhead transmission line(s) that extends greater than 2.0 kilometers beyond the Controlled Area of the generating station up to the point of interconnection with a Transmission Owner’s Facility and is operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region. Furthermore we applaud the committee for using the metric system to identify the acceptable distance for this standard and urge it to remove all references to English units. We strongly suggest this drafting team and all future drafting team abandon the anachronistic English measurement system. This archaic system, based on the length of an average barley corn, should be abandon in all scientific and engineering endeavors.</p>

**Response:** Thank you for your comment. As it discusses in the document titled [“Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface,”](#) the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the

Organization	Yes or No	Question 3 Comment
<p>overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: “Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”</p>		
<p>Southwest Power Pool Standards Development Team</p>	<p>No</p>	<p>There is a possibility of some conflict with the Bulk Electric System Definition. This should be consistent with the Transmission Owner requirements if the lead is determined part of the BES.</p>
<p><b>Response:</b> Thank you for your comment. The SDT intended this standard to be applied to Facilities of GO and TO equally, with the exception of the distance exemption for a generator interconnection Facility. The SDT also notes that FAC-003-2 (approved by the NERC’s Board of Trustees on Nov. 3, 2011) does not rely upon the BES definition to determine the facility to which this standard applies (200 kV or higher, or IROL or WECC Transfer Path).</p>		
<p>South Carolina Electric and Gas</p>	<p>No</p>	<p>There should be no qualifying exemption to FAC-003 for Generator Owners.</p>
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled “<a href="#">Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface</a>,” the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: “Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”</p>		
<p>SERC Planning Standards Subcommittee</p>	<p>No</p>	<p>We believe there should be no exemption for Generator Owners.</p>



Organization	Yes or No	Question 3 Comment
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled <a href="#">“Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface,”</a> the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: “Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”</p>		
PSEG	No	
Infigen Energy US	Affirmative	Infigen finds the DST supporting details regarding FAC-003-X to be appropriate. We support maintaining "reasonable and appropriate" risk prevention measures to minimize encroachment that could trigger vegetation-related outages.
<p><b>Response:</b> Thank you for your comment and support.</p>		
Seattle City Light	Affirmative	Key points are the greater than one mile with clear statement of “...beyond the fenced area of the generating switchyard.”
<p><b>Response:</b> Thank you for your comment and support.</p>		
RES Americas Development / American Wind Energy Association	Yes	Applying the vegetation management requirements to only generator lead lines that extend more than “one mile beyond the fenced area of the generating station switchyard” strikes a reasonable balance among the many stakeholder positions expressed on this topic. We think that as this criterion recognizes that there is little need for a vegetation management plan for shorter lines, it should explicitly state that this is true for all such facilities with lines of that length or smaller.
<p><b>Response:</b> Thank you for your comment and support.</p>		

Organization	Yes or No	Question 3 Comment
Texas Reliability Entity	Yes	In the description of the “second effective date” in FAC-003-X there is an erroneous reference to “Requirement R3,” which should be corrected to “Requirement R1.”
<p><b>Response:</b> Thank you for your comment and support. This conforming change was made.</p>		
Seattle City Light	Yes	Key points are the greater than one mile with clear statement of “...beyond the fenced area of the generating switchyard.”
<p><b>Response:</b> Thank you for your comment and support.</p>		
ACES Power Marketing Standards Collaborators	Yes	<p>We support the changes to FAC-003 suggested by the drafting team because we believe the drafting team has provided the best solution in face of a difficult problem. However, in general, we do not support registration of GOs and GOPs as TOs and TOPs or applicability of any TO/TOP requirements to the GO/GOP simply because they have a radial interconnection greater than one mile in length. While there may be some generators that own interconnecting facilities of significant length operated at a significant voltage that could impact BES reliability, we do not believe that the number of generating facilities that fit into that category is significantly large. When one considers that the majority of generators are still owned and operator by utilities that are also registered as a TO and TOP, there is only a minority subset of generators left that could be considered. NERC has the registration for this remaining set of generators and could use the data to evaluate how many of this remaining subset have interconnections owned by the generator that are substantial enough to affect reliability. It seems that NERC could determine the boundaries of this problem before registering anymore GOs and GOPs as TOs and TOPs or before applying additional requirements through this effort on the GOs and GOPs.</p>
<p><b>Response:</b> Thank you for your comment and support.</p>		

Organization	Yes or No	Question 3 Comment
SERC OC Standards Review Group	Yes	
Southwest Power Pool Regional Entity	Yes	
Florida Municipal Power Agency	Yes	
PPL NERC Registered Affiliates	Yes	
Electric Power Supply Association	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
American Transmission Company	Yes	
Sempra Generation	Yes	

Organization	Yes or No	Question 3 Comment
Entergy Services	Yes	
Xcel Energy	Yes	
Cowlitz County PUD	Yes	
Constellation Power Source Generation	Yes	
Western Electricity Coordinating Council		
Puget Sound Energy, Inc.		
Compliance & Responsibility Organization		
Bonneville Power Administration		
Consolidated Edison Co. of NY, Inc.		
ReliabilityFirst		
Tennessee Valley Authority		

**4. Do you support compliance timeframe for Generator Owners as included and explained in the Implementation Plans for FAC-003-X?**

**Summary Consideration:**

The SDT thanks all stakeholders for their comments. The vast majority of stakeholders support the compliance timeframes as proposed and explained in the Implementation Plan for FAC-003-X.

One commenter found a typo in the effective dates section of FAC-003-X, where one section referenced R3 when it should have referenced R1. That has been corrected in both the standard and the Implementation Plan.

A few stakeholders thought that two years was too long for an Implementation Plan for this standard. The SDT reminded those commenters that the time frame was based on previous stakeholder comments and the fact that the Implementation Plan for Version 0 standards stated “the Version 0 Reliability Standards are generally a translation and clarification of existing operating policies and planning standards, entities that are in compliance with NERC policies and standards today are expected to be able to remain in compliance with the Version 0 Reliability Standards with their existing procedures, tools, and practices.” This process occurred over more than two years. It is therefore reasonable to assume that GOs, having never had to comply with a vegetation management standard, be afforded adequate time to do so.

Beyond the corrected typo, no changes were made.

Organization	Yes or No	Question 4 Comment
Ameren Services	Negative	The 2 year compliance time line is far too long. There is significant industry evidence that was developed in the drafting of Version 2 that supports a one year compliance time-line for new lines. This is evidenced in Version 2. Thus there is no basis for the 2 years.
<p><b>Response:</b> Thank you for your comment. The SDT choose the time in the implementation plan based upon comments of stakeholders and the fact that the implementation plan for <u>Version 0 standards</u> stated “the Version 0 Reliability Standards are generally a translation and clarification of existing operating policies and planning standards, entities that are in compliance with NERC policies</p>		

Organization	Yes or No	Question 4 Comment
<p>and standards today are expected to be able to remain in compliance with the Version 0 Reliability Standards with their existing procedures, tools, and practices.” This process occurred over more than two years. It is therefore reasonable to assume that GOs, having never had to comply with a vegetation management standard, be afforded adequate time to do so.</p>		
Texas Reliability Entity	No	<p>A compliance timeframe for the applicable GOs of two years is too long and the scenario used as a basis provides no timing specifics or details. Moreover, the 12 months for an existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard is arguably the same situation as an applicable GO but the applicable GO has an additional 12 months to come into compliance.</p>
<p><b>Response:</b> Thank you for your comment. The SDT choose the time in the implementation plan based upon comments of stakeholders and the fact that the implementation plan for <a href="#">Version 0 standards</a> stated “the Version 0 Reliability Standards are generally a translation and clarification of existing operating policies and planning standards, entities that are in compliance with NERC policies and standards today are expected to be able to remain in compliance with the Version 0 Reliability Standards with their existing procedures, tools, and practices.” This process occurred over more than two years. It is therefore reasonable to assume that GOs, having never had to comply with a vegetation management standard, be afforded adequate time to do so. The SDT does not believe that a TO’s acquisition of a new asset is the same as applying new requirements to a GO.</p>		
Ingleside Cogeneration LP (Occidental Chemical)	No	<p>Based upon similar issues addressed in Compliance Application Notices (CANs), the drafting team needs to specify when the first vegetation management inspection quarterly report, and any other requirement with an assigned interval in FAC-003-3 or FAC-003-X. Even if the decision is to adopt the same criteria proposed in CAN-0012, the industry is better served with a clear distinction made up front.</p>
<p><b>Response:</b> Thank you for your comment. This is a comment that is outside the scope of the SDT, and in fact deals with a larger body of standards than just FAC-003. No change made.</p>		
PSEG	No	It’s no longer applicable.
<p><b>Response:</b> Thank you for your comment. The SDT acknowledges that in November 2011, NERC’s Board of Trustees adopted FAC-003-2</p>		

Organization	Yes or No	Question 4 Comment
<p>– Transmission Vegetation Management (developed under Project 2007-07 Vegetation Management). Based on this approval, NERC staff will file FAC-003-2 with the applicable regulatory authorities. The Project 2010-07 SDT will move forward with ballots for both FAC-003-3 (proposed changes to the BOT-adopted FAC-003-2) and FAC-003-X (proposed changes to the FERC-approved FAC-003-1) with the intention of eventually only filing FAC-003-3. The SDT has elected to carry FAC-003-X through to ballot because if FAC-003-2 and FAC-003-3 are not approved by FERC, the SDT wants to be ready to file FAC-003-X to ensure that there is a functional entity responsible for managing vegetation on the piece of line commonly known as the generator interconnection Facility.</p> <p>Note that for its recirculation ballot, the SDT will be balloting <b>both</b> FAC-003-3 and FAC-003-X, but stakeholders should <b>not</b> vote as though they are choosing one or the other. As stated above, the SDT plans to present FAC-003-3 alone to NERC’s Board of Trustees, but it wants to have FAC-003-X ready to submit to the Board if, for some reason, neither FAC-003-2 nor FAC-003-3 are approved by FERC. Members of the ballot body should vote on the merits of each version of FAC-003 individually. <b>In other words, stakeholders who support adding GOs to the applicability of FAC-003 should vote in the affirmative for both FAC-003-3 and FAC-003-X.</b></p>		
Manitoba Hydro	No	See question 3 comments.
<p><b>Response:</b> See the SDT’s response to Question 3.</p>		
Southwest Power Pool Standards Development Team	No	The effective dates should be consistent with the original standard. If there is a reason for the extension we would like to know why.
<p><b>Response:</b> Thank you for your comment. The SDT choose the time in the implementation plan based upon comments of stakeholders and the fact that the implementation plan for <a href="#">Version 0 standards</a> stated “the Version 0 Reliability Standards are generally a translation and clarification of existing operating policies and planning standards, entities that are in compliance with NERC policies and standards today are expected to be able to remain in compliance with the Version 0 Reliability Standards with their existing procedures, tools, and practices.” This process occurred over more than two years. It is therefore reasonable to assume that GOs, having never had to comply with a vegetation management standard, be afforded adequate time to do so.</p>		
Southern Company	Yes	The development of a working TVMP will take some time to initialize. The 1 year time frame for R3 is appropriate. The 2 year time frame for all other requirements is appropriate.

Organization	Yes or No	Question 4 Comment
<b>Response:</b> Thank you for your comment and support.		
Seattle City Light	Yes	The explanation deals with the fact that there are simultaneous revisions of FAC-003 underway by two different teams.
<b>Response:</b> Thank you for your comment and support.		
MRO NSRF	Yes	There may be a typographical error on the effective date. As currently drafted the standard states: In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption. Should it be worded as follows? In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 R1 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.
<b>Response:</b> Thank you for your comment. The SDT agrees with you. "Requirement R3," will be corrected to "Requirement R1."		
RES Americas Development/ American Wind Energy Association	Yes	Yes, as with our comments to question 2, since there is no exigent reason why this standard needs to be put in place at once, we support the proposed compliance timeframe. We believe that it will allow generators a reasonable time to comply with the requirement.



Organization	Yes or No	Question 4 Comment
<b>Response:</b> Thank you for your comment and support.		
SERC OC Standards Review Group	Yes	
Northeast Power Coordinating Council, Northeast Power Coordinating Council	Yes	
Southwest Power Pool Regional Entity	Yes	
SERC Planning Standards Subcommittee	Yes	
Florida Municipal Power Agency	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Electric Power Supply Association	Yes	
American Electric Power	Yes	
BP Wind Energy North	Yes	

Organization	Yes or No	Question 4 Comment
America Inc.		
Exelon	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
American Transmission Company	Yes	
South Carolina Electric and Gas	Yes	
Sempra Generation	Yes	
Entergy Services	Yes	
Xcel Energy	Yes	
Cowlitz County PUD	Yes	
Constellation Power Source Generation	Yes	
Western Electricity Coordinating Council		

Organization	Yes or No	Question 4 Comment
Puget Sound Energy, Inc.		
Compliance & Responsibility Organization		
Bonneville Power Administration		
Consolidated Edison Co. of NY, Inc.		
ReliabilityFirst		
Tennessee Valley Authority		

5. In the FAC-003-3 implementation plan, the SDT has attempted to account for a number of different scenarios that could play out with respect to the filing and approvals of FAC-003-2 and FAC-003-3. Do you support this approach? If there are other scenarios that the SDT needs to account for, please suggest them here.

#### Summary Consideration:

The SDT thanks all stakeholders for their comments. The vast majority of stakeholders support the compliance timeframes as proposed and explained in the Implementation Plan for FAC-003-3.

One commenter thought that two years was too long for an Implementation Plan for this standard. The SDT reminded those commenters that the time frame was based on previous stakeholder comments and the fact that the Implementation Plan for Version 0 standards stated “the Version 0 Reliability Standards are generally a translation and clarification of existing operating policies and planning standards, entities that are in compliance with NERC policies and standards today are expected to be able to remain in compliance with the Version 0 Reliability Standards with their existing procedures, tools, and practices.” This process occurred over more than two years. It is therefore reasonable to assume that GOs, having never had to comply with a vegetation management standard, be afforded adequate time to do so.

Some stakeholders expressed confusion about the relationship between FAC-003-3 and the recently BOT-approved FAC-003-2. The SDT acknowledges that in November 2011, NERC’s Board of Trustees adopted FAC-003-2 – Transmission Vegetation Management (developed under Project 2007-07 Vegetation Management). Based on this approval, NERC staff will file FAC-003-2 with the applicable regulatory authorities. The Project 2010-07 SDT will move forward with ballots for both FAC-003-3 (proposed changes to the BOT-adopted FAC-003-2) and FAC-003-X (proposed changes to the FERC-approved FAC-003-1) with the intention of eventually only filing FAC-003-3. The SDT has elected to carry FAC-003-X through to ballot because if FAC-003-2 and FAC-003-3 are not approved by FERC, the SDT wants to be ready to file FAC-003-X to ensure that there is a functional entity responsible for managing vegetation on the piece of line commonly known as the generator interconnection Facility.

All stakeholders should note that for its recirculation ballot, the SDT will be balloting **both** FAC-003-3 and FAC-003-X, but stakeholders should **not** vote as though they are choosing one or the other. As stated above, the SDT plans to present FAC-003-3 alone to NERC’s Board of Trustees, but it wants to have FAC-003-X ready to submit to the Board if, for some reason, neither FAC-003-2 nor FAC-003-3 are approved by FERC. Members of the ballot body should vote on the merits of each version of FAC-003 individually. **In other words, stakeholders who support adding GOs to the applicability of FAC-003 should vote in the affirmative for both FAC-003-3 and FAC-003-X.**

Organization	Yes or No	Question 5 Comment
Manitoba Hydro	No	See question 3 comments.
<p><b>Response:</b> See the SDT’s response to Question 3.</p>		
Southern Company	No	<p>We believe that a standard development process should not have parallel paths where the same version is being modified by multiple teams. The uncertainty in which development path leads to confusion in the industry and ultimately proves to have wasted some resources for the path that does not come to fruition.</p>
<p><b>Response:</b> Thank you for your comment. While the SDT agrees this is not preferable, it was necessary given the urgency of both projects. The SDT did the best it could to describe the scenarios and reasons for posting multiple versions.</p> <p>In November 2011, NERC’s Board of Trustees adopted FAC-003-2 – Transmission Vegetation Management (developed under Project 2007-07 Vegetation Management). Based on this approval, NERC staff will file FAC-003-2 with the applicable regulatory authorities. The Project 2010-07 SDT will move forward with ballots for both FAC-003-3 (proposed changes to the BOT-adopted FAC-003-2) and FAC-003-X (proposed changes to the FERC-approved FAC-003-1) with the intention of eventually only filing FAC-003-3. The SDT has elected to carry FAC-003-X through to ballot because if FAC-003-2 and FAC-003-3 are not approved by FERC, the SDT wants to be ready to file FAC-003-X to ensure that there is a functional entity responsible for managing vegetation on the piece of line commonly known as the generator interconnection Facility.</p>		
Ingleside Cogeneration LP (Occidental Chemical)	Yes	<p>Ingleside Cogeneration agrees that the SDT’s approach is thorough. We are far more concerned about FAC-003’s applicability criteria and implementation time frame at this point - as stated in our responses to questions 3 and 4.</p>
<p><b>Response:</b> Thank you for your comment and support. Please refer to the SDT’s responses to Questions 3 and 4.</p>		
ACES Power Marketing Standards Collaborators	Yes	<p>With recent NERC BOT approval of the FAC-003-2 standard, the drafting team should continue to monitor the standard progress with FERC and make necessary adjustments to the implementation plan.</p>
<p><b>Response:</b> Thank you for your comment. The SDT acknowledges that FAC-003-2 was recently approved by the BOT. The SDT does not</p>		

Organization	Yes or No	Question 5 Comment
<p>see the need to revise the GO implementation plan, as it already accounts for a number of scenarios that could occur based on how FERC handles the filing of FAC-003-2.</p>		
<p>Ameren</p>		<p>(a) There is no technical basis for the one mile length exemption. In fact, one could argue that a very short line, 300 feet in length, that experienced a fault from a tree at "the end of the circuit", i.e near the switchyard fence, would have much more of an impact on the BES because the fault would be limited by much less impedance.</p> <p>(b) It is also unclear in this version if a GO that owned one line that was 1.2 miles in length would have to comply for the entire length of said line, or just 0.2 miles of said line. If the GO is responsible for 1.2 miles, then that argues that the first mile is important and consequently there is no basis for ignoring the first mile on other lines. If the GO is only responsible for 0.2 miles, what is the technical basis to ignore a mile? And would it be the first mile from the switchyard that is ignored, or is the middle mile, or the last mile where it connects to the TO? Or could the GO decide? Or could the GO pick sections of the line that amount to a mile that they can ignore? This seems like something that should be addressed for compliance.</p> <p>(c) The 2 year compliance time line is far too long. There is significant industry evidence that was developed in the drafting of Version 2 that supports a one year compliance time-line for new lines. This is evidenced in Version 2. Thus there is no basis for the 2 years</p>
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled "<a href="#">Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface</a>," the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: "Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are..."</p> <p>With respect to your second comment, the SDT intended for the length qualifier to be just that; if the overhead portion of a Facility</p>		

Organization	Yes or No	Question 5 Comment
<p>exceeds the distance, <a href="#">the entire Facility</a> is subject to the requirements of the standard.</p> <p>The SDT choose the time in the implementation plan based upon reasons it documented in the <a href="#">accompanying implementation plan</a> and also based upon comments of stakeholders.</p>		
PSEG	Yes	
SERC OC Standards Review Group	Yes	
Southwest Power Pool Standards Development Team	Yes	
Northeast Power Coordinating Council, Northeast Power Coordinating Council	Yes	
MRO NSRF	Yes	
SERC Planning Standards Subcommittee	Yes	
Florida Municipal Power Agency	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
Electric Power Supply Association	Yes	

Organization	Yes or No	Question 5 Comment
American Wind Energy Association	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Exelon	Yes	
Seattle City Light	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
American Transmission Company	Yes	
South Carolina Electric and Gas	Yes	
RES Americas Development	Yes	
Sempra Generation	Yes	
Entergy Services	Yes	



Organization	Yes or No	Question 5 Comment
Xcel Energy	Yes	
Cowlitz County PUD	Yes	
Texas Reliability Entity	Yes	
Constellation Power Source Generation	Yes	
Tennessee Valley Authority	Yes	
Southwest Power Pool Regional Entity		
Western Electricity Coordinating Council		
Puget Sound Energy, Inc.		
Compliance & Responsibility Organization		
Bonneville Power Administration		
Consolidated Edison Co. of NY, Inc.		
ReliabilityFirst		

6. In its technical justification document, the SDT reviews all standards that had been proposed for substantive modification in the Ad Hoc Group’s original support and explains why, with the exception of FAC-003, modifying them would not provide any reliability benefit. Do you support these justifications? If you believe the SDT needs to add more information to its rationale for any of these decisions, please include suggested language here.

**Summary Consideration:**

The SDT thanks all stakeholders for their comments.

A few commenters pointed out that the wording in R1 and R2 of PRC-005-1a requires the same explicit reference to a generator interconnection Facility that was added in PRC-004-2a R2. The SDT is developing revisions to PRC-005-1a and will post them soon.

Many commenters encouraged the SDT to reexamine the standards and requirements that FERC and NERC applied to GOs and GOPs in their Milford/Cedar Creek order and draft compliance directive regarding generator leads. The SDT pointed out that the NERC Standard Processes Manual does not address the issue of how to deal with FERC Orders (that don’t include explicit directives), or NERC directives, within the standards process, and until this round of comments, when NERC staff submitted comments, the SDT had no formal mandate that would have made it appropriate to consider the content of the proposed directive.

Based on stakeholder comments, the SDT expanded its technical justification document (posted under “Supporting Materials”) to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.

One commenter remains concerned about the scope of the SDT. The SDT reminded this commenter that its scope is addressed in the SAR and that its intent is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT also refers the commenter to the document titled Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document. Specifically, see the last paragraph on page 4 and first two on page 5.

Organization	Yes or No	Question 6 Comment
Manitoba Hydro	Negative	The intention of the NERC SDT in revising these standards is not clear. While the Technical Justification document states that the SDT intended to focus on a Generator

Organization	Yes or No	Question 6 Comment
		<p>Owner’s radial interconnection facilities, the scope of the revised standard (s) is not confined to such facilities. The very broadly defined term “Facility” is used. Moreover, the Technical Justification document’s reference to the FERC decision in Cedar Creek as a basis for the revision of additional standards is confusing, since that decision did not specifically address the issue of radial facilities and supported NERC’s registration of GOs as TOs.</p>
<p><b>Response:</b> Thank you for your comment. The scope of this SDT is addressed in the <a href="#">SAR</a>. The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT determined that it should first address “low-hanging fruit” and believes these to be sole-use Facilities (see posted examples under “Supporting Materials”) – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP). Through our deliberations, we came to the conclusion that an interconnection Facility owned or operated by a GO or GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT.</p> <p>The SDT also refers the commenter to the document titled <a href="#">Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document</a>. Specifically, see the last paragraph on page 4 and first two on page 5.</p>		
Texas Reliability Entity	No	<p>Our negative votes on FAC-003 reflect our concern that this project has not considered all of the applicable standards. Why did the SDT choose to only review the Ad Hoc Group’s standards when there have been multiple registration appeals in which FERC and NERC have repeatedly cited specific additional TO/TOP standards that were determined to be applicable to GO/GOPs? This SDT project would serve a tremendous value to the ERO and in particular industry if it were to address the technical aspects of the following FERC ordered applicable standards: PRC-001-1 R2, R4; PRC-004-1 R1; TOP-004-2 R6; PER-003-1 R1; FAC-003-1 R1, R2; TOP-001-1a R1 and FAC-004-2 R2. The SDT team should analyze the FERC orders, the applicable standards indicated, and the circumstances and facts involved, and technically justify why no reliability gap exists if these standards are not applied to GO interface facilities. The SDT should include more “technical” information in its technical justification document. For example, in regards to TOP-004-2 R7, the SDT technical</p>

Organization	Yes or No	Question 6 Comment
		<p>justification states that there is no reliability gap because, “. . . because an operator has a fiduciary obligation to protect a Facility for which it is operationally responsible.” An entity having a fiduciary obligation is not a technical justification of why a reliability gap does not exist. Moreover, by that logic there would be no need for many standards because every registered entity has a fiduciary obligation to protect its facilities.</p>
<p><b>Response:</b> Thank you for your comment. The NERC <a href="#">Standard Processes Manual</a> does not address the issue of how to deal with FERC Orders (that don’t include explicit directives), or NERC directives, within the standards process, and until this round of comments, when NERC staff submitted comments, the SDT had no formal mandate that would have made it appropriate to consider the content of the directive you reference.</p> <p>We would like to clarify, in response to the comment concerning TOP-004-2 R7, that in the document titled “<a href="#">Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface</a>” the SDT also stated “FAC-008-1—Facility Ratings Methodology and FAC-009-1—Establish and Communicate Facility Ratings already infer that the reason for establishing a ratings methodology and communicating facility ratings to the Reliability Coordinator, Planning Authority, Transmission Planner, and Transmission Operator is for use in reliable planning and operation of the Bulk Electric System.”</p> <p>Based on your and other comments, we have expanded our technical justification document (posted under “Supporting Materials”) to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.</p>		
PSEG	No	<p>PRC-005-1 - Transmission and Generation Protection System Maintenance and Testing was recommended by the Ad Hoc Group for modification, but not addressed to the technical justification document. It should be.</p>
<p><b>Response:</b> Thank you for your comment. We have reviewed PRC-005-1a and believe that the wording in R1 and R2 of that standard require the same explicit reference to a generator interconnection Facility that was added in PRC-004-2a R2. The SDT is developing revisions to PRC-005-1a and will post them soon.</p>		
Florida Municipal Power	No	see comment to Question 7

Organization	Yes or No	Question 6 Comment
Agency		
<b>Response:</b> See the SDT’s response to Question 7.		
Manitoba Hydro	No	See Question 7 comments.
<b>Response:</b> See the SDT’s response to Question 7.		
MRO NSRF	No	The NSRF has one concern with the current justification and definitions. At some point, if enough interconnections are made to generator outlet leads in accordance with FAC-001, the original generator operator will be a Transmission Operator and a Transmission Owner. This point in time needs to be explicitly defined by the drafting team.
<b>Response:</b> The SDT cannot act on this comment. Registration is outside the scope of this SDT and resides with NERC and the Regional Entity.		
Manitoba Hydro		If the drafting team intends to limit the scope of FAC-001-1 to GO owned radial generator interconnection facilities that are not deemed BES transmission and therefore would not require the registration of the GO as a TO, Manitoba Hydro disagrees with the proposed changes to FAC-001-1 as Generator Owners may not have the models or expertise to perform interconnection studies to determine if there is an impact on the Transmission Network. This concern is echoed in the technical justification document provided by NERC: ‘the SDT acknowledges that the Generator Owner may not, at the time it agrees or is compelled to allow a third part to interconnect, have the necessary expertise to conduct the required interconnect studies to meet this standard... the Generator Owner will have to acquire such expertise. How the Generator Owner chooses to do so is not for the SDT to determine.’ Although it may not be for the SDT to determine how a GO obtains technical expertise, ensuring that such expertise is acquired before a GO conducts the required interconnection studies should be a concern to NERC as this directly affects

Organization	Yes or No	Question 6 Comment
		<p>the reliability of the BES. As a result, all interconnection requests should be implemented by the TO providing the GO with connection to the BES regardless if the interconnection point is within a Generation Owner facility or End-User facility as the TO is in the best position to set unbiased connection requirements to ensure the reliability of the BES is maintained. If the scope of FAC-001-1 also applies to GO owned BES transmission facilities, Manitoba Hydro strongly believes that the Compliance Registry should apply and the GOs should be required to register as a TO and abide by all applicable standards to that functional type. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. Reliability gaps would be better addressed if select GOs and GOPs registered as TOs and TOPs to ensure all reliability standards, including the protection standards, are met so the reliability of the BES is maintained. At this time, this would not lead to a large number of extra registrations since, as stated in the technical justification document, ‘interconnection requests for Generator Owner Facilities are still relatively rare.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees this is a complex issue and did its best to outline how it arrived at its position in the document titled <a href="#">“Technical Justification: FAC-001-1.”</a></p> <p>The SDT points out that if the GO is part of an RTO, then the GO will be coordinating any interconnection studies either directly or indirectly with the RTO interconnection process. If the GO is not part of an RTO, then the GO will be required to follow the pro forma interconnection procedures from Order 2003. The Order 2003 procedures require the GO to coordinate any studies with an affected system which could include Facilities owned by one, or more, TO on the other side of the GO’s existing point of interconnection.</p> <p>The SDT has proposed the modification of a select set of standards so that they apply to GOs and GOPs as an alternative to registering all GOs and GOPs as TOs and TOPs. The SDT does agree that upon interconnection of a third party, other standards or registrations may apply as appropriate.</p>		
Electric Power Supply Association	Affirmative	<p>All TO requirements for FAC-001-1 would apply if and when GO executes an Agreement to evaluate the reliability impact of interconnecting a third party Facility to its existing generation interconnection Facility. The execution of the agreement is necessary to comply with FAC-002-1 and start the compliance clock with the</p>

Organization	Yes or No	Question 6 Comment
		<p>applicable regulatory authority. Thus as the Project 2010-07 Standard Drafting Team (SDT) in its technical justification has stated, “If, and only if, the existing owner of a generator interconnection Facility has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to its existing generation Facility” then FAC-001-1 should apply. EPSA concurs with SDT’s conclusion. The SDT has examined the issue regarding if future requests for transmission service on the interconnection Facility and in doing so acknowledged that when that Facility adopted open access and was providing transmission service it would necessitate re-evaluation of the need for the Facility to be maintained in accordance with FAC-001-1, Requirements 2 and 4. This service would indeed prompt the necessary agreement the SDT contemplates in its technical justification of FAC-001-1. EPSA believes this serves as the necessary trigger for evaluation of Requirements 2 and 4 under FAC-001-1 for GOs.</p>
<p><b>Response:</b> Thank you for your comment and support.</p>		
<p>Infigen Energy US</p>	<p>Affirmative</p>	<p>Infigen supports the FAC-001-1 technical analysis by the Project 2010-07 SDT, which states in part that “If, and only if, the existing owner of a generator interconnection Facility has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to its existing generation Facility would the proposed FAC-001-1 apply”. We agree with the SDT’s reasoning that if the owner of the existing generator interconnection Facility agrees, or is compelled to allow a third party to interconnect, but can do so using existing agreements, contracts, and/or tariffs [to avoid requiring additional executed Agreement(s)], this is the most prudent and effective way to manage this process with continuity. In order to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility more expediently, it can avoid having to develop its own connection requirements or perform additional impact studies, to the extent possible. We find it reasonable to negotiate with the existing Transmission Owner, Transmission Planner, and/or Transmission Service Provider to manage this requirement, utilizing their</p>

Organization	Yes or No	Question 6 Comment
		existing processes and Agreements for the purpose of fulfilling FAC-001-1.
<p><b>Response:</b> Thank you for your comment and support.</p>		
Southern Company	Yes	Additional responses are needed to justify the exclusion of the list of requirements and standards found in the recent FERC order denying the rehearing request of the Compliance Registry Appeals of Cedar Creek and Milford. (135 FERC Para. 61,241). Please see our response to Question 10 for a detailed discussion on this topic.â€,â€,â€,
<p><b>Response:</b> Thank you for your comment. The NERC <a href="#">Standard Processes Manual</a> does not address the issue of how to deal with FERC Orders (that don't include explicit directives), or NERC directives, within the standards process, and until this round of comments, when NERC staff submitted comments, the SDT had no formal mandate that would have made it appropriate to consider the content of the directive you reference.</p> <p>Based on your and other comments, we have expanded our technical justification document (posted under "Supporting Materials") to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.</p>		
Constellation Power Source Generation	Yes	Constellation supports the SDT justifications and offers additional information in our response to question 10.
<p><b>Response:</b> Thank you for your comment and support.</p>		
Ingleside Cogeneration LP (Occidental Chemical)	Yes	Ingleside Cogeneration LP believes the SDT has spent a significant amount of time and effort to demonstrate that only FAC-001, FAC-003, and PRC-004 need to be modified to address any reliability gaps that may exist related to the GO-TO interconnection. We agree that the other standards/requirements identified by the Ad Hoc Group are covered elsewhere.
<p><b>Response:</b> Thank you for your comment and support.</p>		



Organization	Yes or No	Question 6 Comment
American Wind Energy Association	Yes	The reasoning of the SDT is comprehensive and makes a strong case for why there is no need for additional standards to be applied to GO/GOP lead lines as they will not improve the reliability of the Bulk Electric System. In fact, as noted above, such additional standards may decrease reliability by diverting the GO/GOP's resources from the operation of the equipment that actually produces electricity - the generation equipment itself.
<b>Response:</b> Thank you for your comment and support.		
RES Americas Development	Yes	The reasoning of the SDT is comprehensive and makes a strong case for why there is no need for additional standards to be applied to GO/GOP lead lines as they will not improve the reliability of the Bulk Electric System. In fact, as noted above, such additional standards may decrease reliability by diverting the GO/GOP's resources from the operation of the equipment that actually produces electricity - the generation equipment itself.
<b>Response:</b> Thank you for your comment and support.		
SERC OC Standards Review Group	Yes	
Southwest Power Pool Standards Development Team	Yes	
Northeast Power Coordinating Council, Northeast Power Coordinating Council	Yes	
Southwest Power Pool Regional Entity	Yes	

Organization	Yes or No	Question 6 Comment
SERC Planning Standards Subcommittee	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Electric Power Supply Association	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Exelon	Yes	
Seattle City Light	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
American Transmission Company	Yes	
South Carolina Electric and	Yes	

Organization	Yes or No	Question 6 Comment
Gas		
Sempra Generation	Yes	
Xcel Energy	Yes	
Cowlitz County PUD	Yes	
Western Electricity Coordinating Council		
Puget Sound Energy, Inc.		
Compliance & Responsibility Organization		
Bonneville Power Administration		
Independent Electricity System Operator		
Ameren		
Consolidated Edison Co. of NY, Inc.		
Entergy Services		
ReliabilityFirst		

Organization	Yes or No	Question 6 Comment
Tennessee Valley Authority		

**7. The SDT is attempting to modify a set of standards so that radial generator interconnection Facilities are appropriately accounted for in NERC's Reliability Standards, both to close reliability gaps and to prevent the unnecessary registration of GOs and GOPs at TOs and TOPs. Does the set of standards currently posted achieve this goal?**

**Summary Consideration:**

The SDT thanks all stakeholders for their comments. Most commenters support the SDT's work and agree that the set of standards for which the SDT has proposed modification ensure that radial generator interconnection Facilities are appropriately accounted for in NERC's Reliability Standards.

One commenter continues to express confusion about the scope of the SDT's work in general. The SDT reminded this commenter that its scope is addressed in the [SAR](#). The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT determined that it should first address "low-hanging fruit" and believes these to be sole-use Facilities (see posted examples under "Supporting Materials") – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP). Through its deliberations, the SDT came to the conclusion that an interconnection Facility owned or operated by a GO or GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT. The SDT also refers the commenter to the document titled [Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document](#) (specifically, the last paragraph on page 4 and first two on page 5). The SDT has proposed the modification of a select set of standards so that they apply to GOs and GOPs as an alternative to registering all GOs and GOPs as TOs and TOPs, a strategy that has been widely supported by the stakeholder body. The SDT does agree that upon interconnection of a third party, other standards or registrations may apply as appropriate.

One commenter asked the SDT to specify what it means by "radial." By "radial generator interconnection Facilities," the SDT means sole-use Facilities (see posted examples under "Supporting Materials") – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP).

A few commenters suggested that the SDT address those standards cited by FERC and NERC in related projects. The SDT pointed out that the NERC [Standard Processes Manual](#) does not address the issue of how to deal with FERC Orders (that don't include explicit directives), or NERC directives, within the standards process. However, based on stakeholder comments, the SDT has expanded its technical justification document (posted under "Supporting Materials") to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.

One commenter suggested that the SDT include the GO in TOP-004-2 R6, but the SDT continues to maintain that no gap exists because TOP-002-2 R3 already requires the GO to coordinate with its host BA and TSP, who in turn are required to coordinate with their TOPs.

One commenter pointed out that the Data Retention section of the proposed PRC-004-2.1a also requires modification to include the generator interconnection Facility. The SDT agrees and made this change.

Organization	Yes or No	Question 7 Comment
Manitoba Hydro	Negative	<p>Manitoba Hydro has the following comments:</p> <p>1) The intention of the NERC SDT in revising these standards is not clear. While the Technical Justification document states that the SDT intended to focus on a Generator Owner’s radial interconnection facilities, the scope of the revised standard (s) is not confined to such facilities. The very broadly defined term “Facility” is used. Moreover, the Technical Justification document’s reference to the FERC decision in Cedar Creek as a basis for the revision of additional standards is confusing, since that decision did not specifically address the issue of radial facilities and supported NERC’s registration of GOs as TOs.</p> <p>2) Manitoba Hydro strongly disagrees with bypassing the NERC Compliance Registry and only having a limited set of standards apply to the GOs ‘interconnection facilities’ If a Generator Owner wants to own transmission facilities and it falls under the definition of a Transmission Owner under the NERC Registry Criteria, then all the Requirements applicable to a TO should apply. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. Reliability gaps would be better closed if select GOs and GOPs simply registered as TOs and TOPs. At this time, this would not lead to a large number of extra registrations since, as stated in the technical justification document, ‘interconnection requests for Generator Owner Facilities are still relatively rare.</p>
<p><b>Response:</b> Thank you for your comment. The scope of this SDT is addressed in the <a href="#">SAR</a>. The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT determined that it should first address “low-hanging fruit” and believes these to be sole-use Facilities (see posted examples under</p>		

Organization	Yes or No	Question 7 Comment
<p>“Supporting Materials”) – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP). Through our deliberations, we came to the conclusion that an interconnection Facility owned or operated by a GO or GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT.</p> <p>The SDT also refers the commenter to the document titled <a href="#">Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document</a>. Specifically, see the last paragraph on page 4 and first two on page 5.</p> <p>The SDT has proposed the modification of a select set of standards so that they apply to GOs and GOPs as an alternative to registering all GOs and GOPs as TOs and TOPs, a strategy that has been widely supported by the stakeholder body. The SDT does agree that upon interconnection of a third party, other standards or registrations may apply as appropriate.</p>		
Manitoba Hydro	Negative	<p>Manitoba Hydro strongly disagrees with bypassing the NERC Compliance Registry and only having a limited set of standards apply to the GOs ‘interconnection facilities’ If a Generator Owner wants to own transmission facilities and it falls under the definition of a Transmission Owner under the NERC Registry Criteria, then all the Requirements applicable to a TO should apply. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. Reliability gaps would be better closed if select GOs and GOPs simply registered as TOs and TOPs. At this time, this would not lead to a large number of extra registrations since, as stated in the technical justification document, ‘interconnection requests for Generator Owner Facilities are still relatively rare.</p>
<p><b>Response:</b> Thank you for your comment. The SDT has proposed the modification of a select set of standards so that they apply to GOs and GOPs as an alternative to registering all GOs and GOPs as TOs and TOPs, a strategy that has been widely supported by the stakeholder body. The SDT does agree that upon interconnection of a third party, other standards or registrations may apply as appropriate.</p>		
PSEG	No	<p>It would be helpful if the SDT defined what it means by the term “radial generator interconnection Facilities.” Does it mean interconnection Facilities that under Normal Clearing for a fault do not interrupt flows on other BES Elements? This is also confusing because of the radial exclusion included in the BES definition work in</p>

Organization	Yes or No	Question 7 Comment
		Project 2010-17. That definition would allow part of a three-terminal circuit to be excluded from the BES, while the other parts are included in the BES.
<p><b>Response:</b> Thank you for your comment. By “radial generator interconnection Facilities,” the SDT means sole-use Facilities (see posted examples under “Supporting Materials”) – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP). Through our deliberations, we came to the conclusion that an interconnection Facility owned or operated by a GO/GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT.</p>		
Texas Reliability Entity	No	See comment 6.
<p><b>Response:</b> See the SDT’s response to Question 6.</p>		
Manitoba Hydro	No	<p>The SDT’s proposed modifications gives special treatment to the Generator Owner in that it allows the Generator Owner TO status for a couple of standards (FAC-001, FAC-003 and PRC-004), but exempts the Generator Owner from many of the standards applicable to a TO. The NERC Registry Criteria defines the various functional entities. If a Generator Owner wants to own transmission facilities and it falls under the definition of a Transmission Owner under the NERC Registry Criteria, then all the Requirements applicable to a TO should apply. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. Reliability gaps would be better closed if select GOs and GOPs simply registered as TOs and TOPs. At this time, this would not lead to a large number of extra registrations since, as stated in the technical justification document, ‘interconnection requests for Generator Owner Facilities are still relatively rare.</p>
<p><b>Response:</b> Thank you for your comment. The scope of this SDT is addressed in the <a href="#">SAR</a>. The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT determined that it should first address “low-hanging fruit” and believes these to be sole-use Facilities (see posted examples under “Supporting Materials”) – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP). Through our deliberations, we came to the conclusion that an interconnection Facility owned or operated by a GO or</p>		



Organization	Yes or No	Question 7 Comment
<p>GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT.</p> <p>The SDT also refers the commenter to the document titled <a href="#">Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document</a>. Specifically, see the last paragraph on page 4 and first two on page 5.</p> <p>The SDT has proposed the modification of a select set of standards so that they apply to GOs and GOPs as an alternative to registering all GOs and GOPs as TOs and TOPs, a strategy that has been widely supported by the stakeholder body. The SDT does agree that upon interconnection of a third party, other standards or registrations may apply as appropriate.</p>		
<p>Southwest Power Pool Regional Entity</p>	<p>No</p>	<p>The Technical Justification document did not review the standards FERC identified in paragraphs 71 and 87 of 135 FERC ¶ 61,241 ORDER DENYING APPEALS OF ELECTRIC RELIABILITY ORGANIZATION REGISTRATION DETERMINATIONS. The SDT needs to review these standards to determine if changes are needed; otherwise, FERC will require registration of GOs and GOPs as TOs and TOPs to address reliability gaps. If the SDT determines no changes are needed to these FERC-identified standards, they should provide justification.</p>
<p><b>Response:</b> Thank you for your comment. The NERC <a href="#">Standard Processes Manual</a> does not address the issue of how to deal with FERC Orders (that don't include explicit directives) within the standards process. However, based on your and other comments, we have expanded our technical justification document (posted under "Supporting Materials") to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.</p>		
<p>Southern Company</p>	<p>No</p>	<p>We don't believe the effort realizes the goal because 1) it is inclusive of FAC-001 that does not need any modifications and 2) the effort needs to reinforce the appropriate justification not to include the additional standards FERC has identified in their Cedar Creek and Milford Orders.</p>
<p><b>Response:</b> The SDT thanks you for your comment. The SDT believes that comment (1) is a complex issue and did its best to outline how it arrived at its position in the document titled "<a href="#">Technical Justification: FAC-001-1.</a>"</p>		

Organization	Yes or No	Question 7 Comment
		<p>As for comment (2), the NERC <a href="#">Standard Processes Manual</a> does not address the issue of how to deal with FERC Orders (that don't include explicit directives) within the standards process. However, based on your and other comments, we have expanded our technical justification document (posted under "Supporting Materials") to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.</p>
<p>Western Electricity Coordinating Council</p>	<p>No</p>	<p>WECC casts an affirmative vote for the SDT proposal as a necessary but not sufficient step in addressing the GOTO matter. WECC, NERC, and the other Regions developed a subset of Standards and Requirements that were considered necessary to address potential gaps for transmission interconnection facilities and operations to be included in a proposed NERC Directive, which is expected to issue by year-end. The subset of requirements developed for the proposed NERC Directive were informed by the applicable FERC Orders. Consequently, it is important that the SDT address the comparative reliability risks between the proposed NERC Directive List and the SDT Proposal to assure that reliability gaps will not result from the SDT proposal. Please see NERC's proposed Directive for the rationale and technical justification.</p>
<p><b>Response:</b> Thank you for your comment. The NERC <a href="#">Standard Processes Manual</a> does not address the issue of how to deal with FERC Orders (that don't include explicit directives), or NERC directives, within the standards process, and until this round of comments, when NERC staff submitted comments, the SDT had no formal mandate that would have made it appropriate to consider the content of the directive you reference.</p> <p>However, based on your and other comments, we have expanded our technical justification document (posted under "Supporting Materials") to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.</p>		
<p>Florida Municipal Power Agency</p>		<p>FMPA believes that TOP-004-2 R6.2 ought to also be addressed in the standards as applicable to GOPs. The requirements reads:R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and</p>

Organization	Yes or No	Question 7 Comment
		<p>implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: R6.2. Switching transmission elements. Although planned outages are covered in other standards applicable to a GOP, switching to close / synchronize a generator back to the system is not specifically covered in the standards. Some have argued that TOP-002-2 R3 causes GOPs to coordinate its current day plans with the TOP; however, the name of the standard is “Transmission Operations Planning” and therefore implies the availability of the generator and related equipment and not necessary implies the policies and procedures for switching operations; which includes synchronization. FMPA cannot imagine a generator that would not have such switching / synchronization policies and procedures coordinated with its interconnecting TOP; as such would normally be required through a Large Generator Interconnection Agreement through a pro forma OATT; however, FMPA is not aware of any instance in the standards that covers this. As such, FMPA recommends including TOP-004-2 R6.2 as being applicable to a GOP.</p>
<p><b>Response:</b> Thank you for your comment. We don’t agree that the gap exists because TOP-002-2 R3 already requires the GO to coordinate with its host BA and TSP, who in turn are required to coordinate with their TOPs.</p>		
Manitoba Hydro		<p>If the redline changes are implemented, GOs are removed from R4, thereby removing the obligation for GOs to maintain their connection requirements. If GOs are included in FAC-001, they should be held accountable to the same level as TOs and should be required to maintain their connection requirements. Requiring a GO to maintain connection requirements would be especially beneficial to the GO themselves. In the majority of instances, any GO that is an Applicable Entity for FAC-001 would initially be inexperienced in performing interconnection studies and would benefit from regular and frequent review of their connection requirements as experience and expertise are gained.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees this is a complex issue and did its best to outline how it arrived at its position</p>		

Organization	Yes or No	Question 7 Comment
in the document titled " <a href="#">Technical Justification: FAC-001-1.</a> "		
SERC OC Standards Review Group		Please list the set of standards are you referencing.
<b>Response:</b> The SDT is referring to those standards posted for comment (FAC-001-1, FAC-003-X, FAC-003-3, and PRC-004-2.1).		
Constellation Power Source Generation, Inc.	Affirmative	Constellation appreciates and supports the work of the standard drafting team. We recognize the significant time invested by technical experts from industry to consider the appropriate application of reliability standards to address concerns raised about coverage of transmission at the generator interface. The drafting team analysis identified the standards in need of revision to appropriately address the reliability concerns raised. Please see more detailed comments submitted in the Project 2010-07 comment form submitted on November 18, 2011.
<b>Response:</b> Thank you for your comment and support.		
Infigen Energy US	Affirmative	Infigen finds the SDT supporting measures and analysis regarding FAC-003-3 to be appropriate, and believes that it is prudent for Generation Owners and Transmission Owners to manage vegetation maintenance records/inspections accordingly. We support maintaining "reasonable and appropriate" risk prevention measures to minimize encroachment that could trigger vegetation-related outages.
<b>Response:</b> Thank you for your comment and support.		
PPL EnergyPlus LLC	Affirmative	PPL Generation, LLC, on behalf of its NERC-registered subsidiaries, appreciates the effort by the Standard Development Team to address the GO-TO interface issues in a manner that enhances the reliability of the BES without adding unnecessary burden on Generators. As registered GOs/GOPs, the PPL Generation registered entities agree with the changes made by the SDT to these three standards. To the extent that GOs/GOPs are required to register as TOs/TOPs, PPL Generation would have

Organization	Yes or No	Question 7 Comment
		significant concerns with meeting the compliance requirements applicable to TOs in the standards included in the scope of this Project, as well as other TO/TOP requirements throughout other NERC standards.
<p><b>Response:</b> Thank you for your comment and support.</p>		
Puget Sound Energy, Inc.	Affirmative	The changes to this standard are minor, and seem to be centered around including "generator Interconnection facilities" to R2. This added phrase and the statement in 1.4 Data Retention "Generator Owner that owns a generation Protection System" seems to assume that the generator owner and generator interconnection facilities owner is always the same. This is not always the case, and will make this standard language confusing to prepare evidence for. A suggestion would be to revise the language to allow for a separate generator owner and generator interconnection facilities owner.
<p><b>Response:</b> Thank you for your comment. The SDT believes that the language makes clear that an entity need only be concerned with the Elements or Facilities that it owns.</p> <p>The SDT agrees with your comment regarding the language in the Data Retention section and has modified that section as follows: "The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation or generator interconnection Protection System..."</p>		
Southwest Transmission Cooperative, Inc. / ACES Power Marketing	Affirmative	We largely support the changes made by drafting team because we believe the drafting team has provided the best solution in face of a difficult problem. However, in general, we do not support registration of GOs and GOPs as TOs and TOPs or applicability of any TO/TOP requirements to the GO/GOP simply because they have a radial interconnection greater than one mile in length. While there may be some generators that own interconnecting facilities of significant length operated at a significant voltage that could impact BES reliability, we do not believe that the number of generating facilities that fit into that category is significantly large. When one considers that the majority of generators are still owned and operator by utilities that are also registered as a TO and TOP, there is only a minority subset of generators

Organization	Yes or No	Question 7 Comment
		<p>left that could be considered. NERC has the registration for this remaining set of generators and could use the data to evaluate how many of this remaining subset have interconnections owned by the generator that are substantial enough to affect reliability. It seems that NERC could determine the boundaries of this problem before registering anymore GOs and GOPs as TOs and TOPs or before applying additional requirements through this effort on the GOs and GOPs. Subjecting a GO/GOP to any TO/TOP standards requirements should require a clear demonstration of the reliability gap in each instance. Some additional changes are necessary to FAC-001.</p>
<p><b>Response:</b> Thank you for your comment and support. We are unsure as to what changes to FAC-001 you feel are necessary unless you are referring to comments stated previously.</p>		
<p>Ingleside Cogeneration LP (Occidental Chemical)</p>	<p>Yes</p>	<p>Although the SDT is nearing conclusion on the closing of reliability gaps, the unnecessary registration of GOs and GOPs as TOs and TOPs is far from resolved in our view. Ingleside Cogeneration’s concern is based upon NERC’s recent proposal to dictate an interim GO-TO interconnection solution which completely bypasses the Standards Development Process. Frankly, it seriously brings to question the nature of the consensus-driven process - which appears to be moving in a dictatorial direction.</p>
<p><b>Response:</b> Thank you for your comment and support.</p>		
<p>American Wind Energy Association</p>	<p>Yes</p>	<p>AWEA believes that the standards modifications proposed by the SDT should address any genuine reliability gap with regard to generator lead lines, rather than just perceived but unsupported threats. To that end, we support the approach that the SDT appears to be taking of modifying a limited number of applicable standards so that they apply to GO/GOP lead lines. In particular, we fully support the fact that the SDT recognizes that GO/GOPs should not automatically be required to register as TO/TOPs simply because of their ownership of generator lead lines. The SDT correctly recognizes that such registration should be done based on a case-by-case determination. As already noted, registering a GO/GOP as a TO/TOP may actually decrease reliability.</p>

Organization	Yes or No	Question 7 Comment
<b>Response:</b> Thank you for your comment and support.		
RES Americas Development	Yes	We believe that the standards modifications proposed by the SDT should address any genuine reliability gap with regard to generator lead lines, rather than just perceived but unsupported threats. To that end, we support the approach that the SDT appears to be taking of modifying a limited number of applicable standards so that they apply to GO/GOP lead lines. In particular, we fully support the fact that the SDT recognizes that GO/GOPs should not automatically be required to register as TO/TOPs simply because of their ownership of generator lead lines. The SDT correctly recognizes that such registration should be done based on a case-by-case determination. As already noted, registering a GO/GOP as a TO/TOP may actually decrease reliability.
<b>Response:</b> Thank you for your comment and support.		
Southwest Power Pool Standards Development Team	Yes	
Northeast Power Coordinating Council, Northeast Power Coordinating Council	Yes	
MRO NSRF	Yes	
SERC Planning Standards Subcommittee	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
ACES Power Marketing	Yes	

Organization	Yes or No	Question 7 Comment
Standards Collaborators		
Electric Power Supply Association	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Exelon	Yes	
Seattle City Light	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
Ameren	Yes	
American Transmission Company	Yes	
Sempra Generation	Yes	
Xcel Energy	Yes	



Organization	Yes or No	Question 7 Comment
Cowlitz County PUD	Yes	
Constellation Power Source Generation	Yes	
Puget Sound Energy, Inc.		
Compliance & Responsibility Organization		
Bonneville Power Administration		
South Carolina Electric and Gas		
Consolidated Edison Co. of NY, Inc.		
Entergy Services		
ReliabilityFirst		
Tennessee Valley Authority		

**8. If you answered “yes” to Question 7, are the modifications the SDT has made in this posting the appropriate ones?**

**Summary Consideration:**

The SDT thanks all stakeholders for their comments. In this section, commenters either offered their support or directed the SDT to their comments on other questions in this report.

Organization	Yes or No	Question 8 Comment
Ameren	No	Please refer to our comments in responses to #3, #4, and #5 above.
<b>Response:</b> Please see the SDT’s responses to Questions 3, 4, and 5.		
Texas Reliability Entity	No	See comment 6.
<b>Response:</b> Please see the SDT’s response to Question 6.		
Ingleside Cogeneration LP (Occidental Chemical)	No	See comments to questions 1 through 4.
<b>Response:</b> Please see the SDT’s responses to Questions 1-4.		
SERC Planning Standards Subcommittee	No	See our comments above for question # 3.
<b>Response:</b> Please see the SDT’s response to Question 3.		
South Carolina Electric and Gas	No	The modifications are appropriate with the exception noted in question #3.
<b>Response:</b> Please see the SDT’s response to Question 3.		
ACES Power Marketing	No	The modifications are largely the appropriate ones with the exceptions we noted in Q1

Organization	Yes or No	Question 8 Comment
Standards Collaborators		and Q10.
<b>Response:</b> Please see the SDT’s responses to Questions 1 and 10.		
Southwest Power Pool Standards Development Team	No	We agree that the standards being addressed are correct. See above comments. There are some issues with the determination of which facilities are deemed BES since ownership of what may be a BES facility may not always be by a Transmission Owner. All relevant standards should apply to BES facilities regardless of ownership.
<b>Response:</b> Thank you for your comment.		
PSEG	No	
<b>Response:</b>		
SERC OC Standards Review Group		See comments on Question 7. If the standards referenced in question 7 are FAC-001, FAC-003 and PRC-004, we would answer yes to this question.
<b>Response:</b> Thank you for your comment and support.		
Southern Company	Yes	“The version history table is incorrect - change version 3 to version 2.1.”
<b>Response:</b> Thank you for your comment. We have made this change.		
RES Americas Development/ American Wind Energy Association	Yes	For the most, we agree that the SDT proposal strikes a reasonable balance and provides the requisite level of clarity and certainty necessary for GO/GOPs to understand their responsibilities and compliance requirements.
<b>Response:</b> Thank you for your comment and support.		
MRO NSRF	Yes	The NSRF agrees if the drafting team incorporates as suggested improvements

Organization	Yes or No	Question 8 Comment
<b>Response:</b> Thank you for your comment and support.		
Northeast Power Coordinating Council, Northeast Power Coordinating Council	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
Electric Power Supply Association	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Exelon	Yes	
Seattle City Light	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
American Transmission	Yes	

Organization	Yes or No	Question 8 Comment
Company		
Sempra Generation	Yes	
Xcel Energy	Yes	
Cowlitz County PUD	Yes	
Constellation Power Source Generation	Yes	

**9. If you answered “no” to Question 7, what standards need to be added or removed to achieve the SDT’s goal? Please provide technical justification for your answer.**

**Summary Consideration:**

The SDT thanks all stakeholders who submitted comments. Few stakeholders suggested that standards need to be added or removed to achieve the SDT’s goal.

One commenter pointed out that PRC-005-1a required the same kind of change made in the proposed PRC-004-2.1a to ensure that generator interconnection Facility Protection Systems are included within that standard. The SDT agrees with this suggestion and has initiated a process to modify R1 and R2 in PRC-005-1a.

A few commenters returned to FAC-001-1 and stated their concern about the feasibility of adding FAC-001-1 to the applicability section of this standard. The SDT agrees with commenters that the issues surrounding the interconnection of a third party Facility to a GO’s existing Facilities are complex ones, and reminded commenters that it did its best to address these complexities in the resource document titled “[Technical Justification: FAC-001-1](#).” The SDT also points out that if the GO is part of an RTO, then the GO will be coordinating any interconnection studies either directly or indirectly with the RTO interconnection process. If the GO is not part of an RTO, then the GO will be required to follow the pro forma interconnection procedures from Order 2003. The Order 2003 procedures require the GO to coordinate any studies with an affected system which could include Facilities owned by one, or more, TO on the other side of the GO’s existing point of interconnection. The SDT acknowledges that upon interconnection of a third party, other standards or registrations may apply as appropriate.

Some commenters suggested that the SDT reexamine the standards cited in the Milford and Cedar Creek FERC orders. The SDT continues to find clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards and not requiring the GO or GOP to register as a TO or TOP. However, to address stakeholder concern, the SDT has expanded its technical justification document (posted under “Supporting Materials”) to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive.

Organization	Yes or No	Question 9 Comment
Cowlitz County PUD	No	N/A
Manitoba Hydro	No	See question 7 comments.

Organization	Yes or No	Question 9 Comment
<p><b>Response:</b> See the SDT’s response to Question 7.</p>		
<p>Southern Company</p>	<p>Yes</p>	<p>Southern does not think that the revision to FAC-001-1 is necessary. A Generator Owner (GO) cannot assess reliability impacts to the Bulk Electric System (BES) and determine acceptability without support and involvement of the applicable owner and operator of the Transmission System (i.e., the “interconnected TO” or “interconnected TP”). A generator tie-line does not equate to a Transmission System. A GO must already adhere to a TO’s Facility connection requirements whether the GO wants to connect additional facilities or a third parties’ facilities to its own interconnection Facilities. Stated another way, the GO does not need Facility Connection requirements to govern how multiple units are tied to a collector bus so why are they needed for a third party to connect to an existing tie-line? In either case it is the interconnected TO or interconnected TP that has connection requirements that must be fulfilled. The GO’s Interconnection Agreement would prohibit it from connecting additional facilities without a new application for Interconnection Service with its interconnected TO or interconnected TP. A GO should not need to develop “connection requirements” unless it is in the business of owning and operating facilities independently of its interconnected TO or interconnected TP. We do not believe a reliability gap exists in FAC-001-1 because the requestor for interconnecting another Facility to an existing generation Facility must coordinate with the applicable TO, TP, and PA in accordance with FAC-002-0 to ensure they meet all applicable facility connection and performance requirements. If and when there is an agreement in place for a third party to connect to a generator tie-line then the tie-line would become part of the integrated system and its purpose and the owner’s function would likely warrant registration as a TO/TOP and FAC-001 would then apply. The following excerpt from the 2010-07 Background Resource White Paper acknowledges that this may be necessary: “The drafting team also acknowledges that, if another party interconnects to a Facility owned by a Generator Owner, there may be the need to address MOD or TPL standards. However, the drafting team believes that this, too, is best handled through specific evaluation, perhaps accompanied by changes to the</p>

Organization	Yes or No	Question 9 Comment
		<p>compliance registry. Entities that face this kind of scenario may also meet criteria applicable to other registrations such as Transmission Service Provider or Transmission Planner.” [Arguments related to jurisdictional, interconnection policy and open access transmission tariff issues](1) Because of (a) jurisdiction under Section 215, (b) FERC’s interconnection policy, and (c) the requirements of the pro forma open access transmission tariff (OATT), a GO should not be required to comply with FAC-001-1 until that GO’s generating Facility reaches commercial operation. NERC should not make facilities subject to the mandatory reliability standards before the facilities are actually part of the BES.(a) Jurisdiction under FPA Section 215. First, it is not clear that NERC or FERC has jurisdiction under FPA Section 215 to require generation facilities that have not actually reached commercial operation to be subject to reliability standards. Section 215(a)(2) of the FPA defines the “Electric Reliability Organization” as “the organization certified by the Commission ... the purpose of which is to establish and enforce reliability standards for the bulk-power system, subject to Commission review.” Further, (a)(3) provides that “The term ‘reliability standard’ means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system. The term includes requirements for the operation of existing bulk-power system facilities ... the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system ....” Thus, under Section 215 NERC can develop reliability standards that address requirements for existing bulk-power system facilities (i.e., facilities that have reached “commercial operation”) and for the design of planned additions or modifications. It is logical to interpret the phrase “design of new facilities” as meaning that new facilities must be designed to comply with existing reliability standards. However, it is not clear that this provision should be interpreted as requiring that a generating facility that has not yet reached commercial operation should be subject to reliability standards (including audit and penalties). Therefore, the GO with the existing generation facilities should not be required to incorporate the proposed generation facility into its Facility connection requirements before the proposed generation facility is subject to NERC or FERC jurisdiction. (b) FERC’s</p>



Organization	Yes or No	Question 9 Comment
		<p>interconnection policy. In addition, the revised FAC-001 would appear to place restrictions on interconnection customers in contravention of Order Nos. 2003 and 2006 (Standard Large and Small Interconnection Procedures and Agreements). FERC was very concerned about the ability of interconnection customers to interconnect their generating facilities and gave them a fair amount of flexibility. However, this revised FAC-001 would appear to restrict some of this flexibility.(i) Order No. 2003 gives the interconnection customer the ability to terminate a proposed interconnection on ninety days notice. Therefore, the interconnection customer is not required to build the facility. However, this revised FAC-001 appears to assume that the interconnection customer does not have this flexibility. What if the interconnection customer (the GO building a new generator on its site or the third party building a new generation facility) decides to terminate the Large Generator Interconnection Agreement (LGIA) or not proceed with the generation facility? In such event, the GO may be required to revert to its previous Facility connection requirements in order to accommodate the original configuration. (ii) The LGIA permits modifications to the proposed interconnection. How would this affect the Facility connection requirements? How long would the GO have to revise its Facility connection requirements? In the event that there is a single modification, or perhaps multiple modifications, how does the GO stay in compliance with this standard? (iii) FAC-001-1, R4 provides that each GO with Facility connection requirements and each TO shall maintain Facility connection requirements and make documentation of these requirements available to users of the Transmission System upon request. However, Large Generator Interconnection Procedures (LGIP), Section 3.4 requires the posting of certain interconnection information but the identity of the interconnection customer is not to be disclosed (unless it is an Affiliate). Requirement R4 would appear to potentially require disclosure of information and (more importantly) of the interconnection customer's identity in contravention of the requirements in Order No. 2003 and the LGIP.(c) OATT requirements. The definition of “applicable Generator Owner” (Section 4.2.1) and Requirement R2 provide that the GO will have an executed Agreement to evaluate the impact of interconnecting a new facility to the GO’s</p>

Organization	Yes or No	Question 9 Comment
		<p>existing generation facility. This statement is ambiguous. This statement could be understood to mean that the GO of the existing generation Facility will enter into an Agreement with the GO proposing to interconnect and the existing GO will evaluate the impact of the proposed interconnection. However, requests to interconnect new generation are processed under an OATT. In that case, it would be the Transmission Provider (not the existing GO) that would evaluate the impact of interconnecting the new facility. Thus, the language in FAC-001-1 would need to be revised to clarify that the owner of the new facility will need to interconnect under the OATT of an appropriate Transmission Provider (i.e., the Transmission Provider to which the existing GO is interconnected, not with the existing GO). Therefore, the owner of the new facility will most likely be the entity with the executed Agreement (with the Transmission Provider). Another consideration is that the existing GO could be developing a merchant transmission line. In that case, the existing GO would need to evaluate whether it needs have its own OATT and OASIS. In that case, the new generator owner would be interconnecting to the existing GO. However, the existing GO's line would not be a generator tie-line. This issue is not clear from the draft standard. (2) The following are suggested changes to FAC-001-1. (a) We recommend the Purpose statement be revised to state, "To avoid adverse impacts on BES reliability..." (b) It is unclear in Applicability section 4.2.1 that the term "Agreement" means that the GO has an executed agreement with a TO/TSP or that the GO and the third party have an executed agreement. Without further explanation, the capitalized term "Agreement" has the effect of introducing confusion. If the SDT does not intend to propose a new addition to the NERC Glossary of Terms, it should use the lower case term, "agreement." With respect to the capitalized term, "Transmission System," the SDT should consider clarifying if it intends to propose adding this to the Glossary. (3) Effect of the proposed revisions to FAC-001-1 on FAC-002-1.(a) As drafted, there are scenarios under which a new GO may attempt to interconnect to an existing GO even though, as explained above, the interconnection should actually be done to the appropriate Transmission Provider. If the appropriate Transmission Provider is not included in the evaluation of the interconnection various types of harm may occur. In</p>

Organization	Yes or No	Question 9 Comment
		<p>such event, the TPs and PAs should be indemnified from any liability with respect to performance of the evaluations required by FAC-002. (b) FAC-001 and FAC-002 should be revised to be clear that the existing GO and any new GOs must coordinate any interconnection with the appropriate Transmission Provider, TP and PA.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees this is a complex issue and did its best to outline how it arrived at its position in the document titled "<a href="#">Technical Justification: FAC-001-1.</a>"</p> <p>The SDT points out that if the GO is part of an RTO, then the GO will be coordinating any interconnection studies either directly or indirectly with the RTO interconnection process. If the GO is not part of an RTO, then the GO will be required to follow the pro forma interconnection procedures from Order 2003. The Order 2003 procedures require the GO to coordinate any studies with an affected system which could include Facilities owned by one, or more, TO on the other side of the GO's existing point of interconnection.</p> <p>The SDT does agree that upon interconnection of a third party, other standards or registrations may apply as appropriate.</p>		
PSEG	Yes	<p>We believe that the Ad Hoc Group's suggestions regarding PRC-005-1 - Transmission and Generation Protection System Maintenance were correct and that this standard should have been modified by the SDT in a manner similar to the way the SDT modified PRC-004-2. This would require modifying R1 and R2 in PRC-005-1a (the current version) to include protection systems in the generator interconnection Facility. In addition, the SDT should evaluate modifying PER-002-0 - Operation Personnel Training. In doing so the SDT completes one of the open FERC directives in Order 693. Paragraph 1363 addresses GOP training:1363. Further, the Commission agrees with MidAmerican, SDG&amp;E and others that the experience and knowledge required by transmission operators about Bulk-Power System operations goes well beyond what is needed by generation operators; therefore, training for generator operators need not be as extensive as that required for transmission operators. Accordingly, the training requirements developed by the ERO should be tailored in their scope, content and duration so as to be appropriate to generation operations personnel and the objective of promoting system reliability. Thus, in addition to modifying the Reliability Standard to identify generator operators as applicable entities, we direct the ERO to develop specific Requirements addressing the scope,</p>

Organization	Yes or No	Question 9 Comment
		content and duration appropriate for generator operator personnel.
<p><b>Response:</b> Thank you for your comment. The SDT agrees with the comment concerning PRC-005-1a and will be initiating a process to make that change.</p> <p>With respect to PER-002-0, the SDT continues to find that there are no clear and technical reliability reasons that support adding GOP requirements to any PER standard <i>based on the fact that the GOP operates a generator interconnection Facility</i>. While the SDT does not necessarily disagree that some training requirements for GOPs may be necessary, it does not see how these changes fall within its scope.</p>		
Ingleside Cogeneration LP (Occidental Chemical)		Ingleside Cogeneration LP believes that the set of standards proposed by the SDT is technologically accurate and defensible. The open issue is if the ERO and FERC expect more standards to be included - whether based upon sound reliability principals or not.
<p><b>Response:</b> Thank you for your comment and support.</p>		
Western Electricity Coordinating Council		Please see response to question #7.
<p><b>Response:</b> See the SDT's response to Question 7.</p>		
Texas Reliability Entity		See comment 6.
<p><b>Response:</b> See the SDT's response to Question 6.</p>		
SERC OC Standards Review Group		See comments on Questions 7 & 8.
<p><b>Response:</b> See the SDT's responses to Questions 7 and 8.</p>		
Florida Municipal Power		see response to Question 7

Organization	Yes or No	Question 9 Comment
Agency		
<p><b>Response:</b> See the SDT’s response to Questions 7.</p>		
Manitoba Hydro		<p>The revision to FAC-001-1 R2 may be problematic, depending on what was intended. Under the revised requirement, the obligation to comply is dependent on the execution of an agreement to evaluate reliability impacts under FAC-002-1. However, FAC-002-1 does not clearly require the execution of an agreement by the Generator Owner. FAC-002-1 only requires the Generator Owner to “coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority”. Accordingly if a Generator Owner coordinates without executing an agreement to perform an assessment, compliance with FAC-001 R1 will not be required.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees this is a complex issue and did its best to outline how it arrived at its position in the document titled “<a href="#">Technical Justification: FAC-001-1</a>.”</p>		
Southwest Power Pool Regional Entity		<p>The SDT should consider the standards that FERC identified in 135 FERC ¶ 61,241.</p>
<p><b>Response:</b> Thank you for your comment. The NERC <a href="#">Standard Processes Manual</a> does not address the issue of how to deal with FERC Orders (that don’t include explicit directives). However, based on your and other comments, we have expanded our technical justification document (posted under “Supporting Materials”) to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.</p>		

**10. Do you have any other comments that you have not yet addressed? If yes, please explain.****Summary Consideration:**

The SDT thanks all stakeholders for their comments. In this section, many stakeholders offered supportive comments. Others offered a variety of suggestions, many of which were addressed.

One commenter suggested that the word “system” should not be capitalized in “Transmission System” in FAC-001-1 because the NERC glossary term “System” does not apply within the standard. The SDT agreed with this suggestion, and changed all references to “Transmission System” to “interconnected Transmission systems” for consistency in other parts of the standard and with FAC-002. Another commenter pointed out that “within” should be “with” in Section 4.2.1, and the SDT made this change.

A few commenters repeated their concern with the exclusion in FAC-003 for GOs with specific kinds of interconnection Facilities. For these commenters, the SDT reemphasized that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.

To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: “Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”

Some stakeholders offered comments that were outside the scope of this SDT’s work. A few offered comments on the overall strategy of the FAC-003-2 standard, and the SDT informed them that these comments should have been submitted when the Project 2007-7 Vegetation Management posted its work for comment.

One commenter suggested changes to the VSLs for R1 and R4. Because the SDT made no changes to these requirements, modifying the VSLs for these requirements is outside the scope of this team. This item will be added to the issues database.

Several stakeholders suggested the SDT review the standards cited in the draft NERC directive regarding generator interconnection leads and in the FERC orders regarding Milford and Cedar Creek. The SDT continues to find clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards and not requiring the GO or GOP to register as a TO or TOP. However, to address stakeholder concern, the SDT has expanded its

technical justification document (posted under “Supporting Materials”) to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive.

Organization	Yes or No	Question 10 Comment
Gainesville Regional Utilities	Negative	<p>1. It would seem that the impetus for FAC003 is to eliminate vegetation related outages within the rights-of-way as defined and subject to the exclusions as stated in footnote</p> <p>2. Thus the requirement is to manage the ROW to prevent vegetation related sustained outages with the measure being no outages. With grow-ins and fall-ins from within the defined ROW being controllable factors. 2. Including encroachments leaves the door open for fines to be imposed with no actual outage(s) having occurred. This may be like being found guilty of a crime that has not yet taken place.</p> <p>3. Combine vegetation related sustained outages by “grow-ins” and “blowing together of lines and vegetation located inside the ROW” as one item as they are both consequences of the growth of vegetation either vertically and horizontally.</p> <p>4. Leave vegetation related sustained outages by “fall-in” as a standalone as this will be related to structural problems occurring from a variety of sources.</p> <p>5. Combine R3 and R7 to R1 (development and implementation of a Transmission Vegetation Management Plan which shall include documented maintenance strategies or procedures or processes or specifications, delineation of an annual work plan and completion of same). Thus this would be the competency based requirements as a program without execution is meaningless.</p> <p>6. R1 and R2 become R2 and R3.</p>
<p><b>Response:</b> Thank you for your comment. This is outside the scope of the <a href="#">SAR</a> for this project. This SDT did review comments submitted as part of the <a href="#">Project 2007-07</a> effort and found that a response to this comment was provided. No change made.</p>		
Northern Indiana Public Service Co.	Negative	Ballot needs work

Organization	Yes or No	Question 10 Comment
<p><b>Response:</b> The SDT does not understand your specific concern.</p>		
<p>PSEG Energy Resources &amp; Trade LLC, PSEG Fossil LLC, Public Service Electric and Gas Co.</p>	<p>Negative</p>	<p>FAC-003-X is not applicable since FAC-003-2 was approved by the BOT on November 4, 2011</p>
<p><b>Response:</b> Thank you for your comment. You are correct that in November 2011, NERC’s Board of Trustees adopted FAC-003-2 – Transmission Vegetation Management (developed under Project 2007-07 Vegetation Management). Based on this approval, NERC staff will file FAC-003-2 with the applicable regulatory authorities. The Project 2010-07 SDT will move forward with ballots for both FAC-003-3 (proposed changes to the BOT-adopted FAC-003-2) and FAC-003-X (proposed changes to the FERC-approved FAC-003-1) with the intention of eventually only filing FAC-003-3. The SDT has elected to carry FAC-003-X through to ballot because if FAC-003-2 and FAC-003-3 are not approved by FERC, the SDT wants to be ready to file FAC-003-X to ensure that there is a functional entity responsible for managing vegetation on the piece of line commonly known as the generator interconnection Facility.</p> <p>Note that for its recirculation ballot, the SDT will be balloting <b>both</b> FAC-003-3 and FAC-003-X, but stakeholders should <b>not</b> vote as though they are choosing one or the other. As stated above, the SDT plans to present FAC-003-3 alone to NERC’s Board of Trustees, but it wants to have FAC-003-X ready to submit to the Board if, for some reason, neither FAC-003-2 nor FAC-003-3 are approved by FERC. Members of the ballot body should vote on the merits of each version of FAC-003 individually. <b>In other words, stakeholders who support adding GOs to the applicability of FAC-003 should vote in the affirmative for both FAC-003-3 and FAC-003-X.</b></p>		
<p>Hydro-Quebec TransEnergie</p>	<p>Negative</p>	<p>Hydro-Quebec TransEnergie is casting a negative vote again because our comment from the last posting was not considered in the current draft: The minimum frequency of Vegetation Inspection should be based upon an average growth rates of smaller regions than all North America. Example, above the latitude of 50 degrees North, the vegetation growth rates is limited. The Vegetation Inspection frequency in the territories located above 50 degrees of latitude must be relaxed to 3 years.</p>
<p><b>Response:</b> Thank you for your comment. This is outside the scope of the <a href="#">SAR</a> for this project. This SDT did review comments submitted as part of the <a href="#">Project 2007-07</a> effort and did not find this comment had been submitted as part of that project effort. No changes made.</p>		



Organization	Yes or No	Question 10 Comment
New Brunswick System Operator	Negative	Since NBSO voted 'affirmative' for FAC-003-3, it makes sense for us to vote 'negative' for this standard.
<p><b>Response:</b> Thank you for your comment. In November 2011, NERC’s Board of Trustees adopted FAC-003-2 – Transmission Vegetation Management (developed under Project 2007-07 Vegetation Management). Based on this approval, NERC staff will file FAC-003-2 with the applicable regulatory authorities. The Project 2010-07 SDT will move forward with ballots for both FAC-003-3 (proposed changes to the BOT-adopted FAC-003-2) and FAC-003-X (proposed changes to the FERC-approved FAC-003-1) with the intention of eventually only filing FAC-003-3. The SDT has elected to carry FAC-003-X through to ballot because if FAC-003-2 and FAC-003-3 are not approved by FERC, the SDT wants to be ready to file FAC-003-X to ensure that there is a functional entity responsible for managing vegetation on the piece of line commonly known as the generator interconnection Facility.</p> <p>Note that for its recirculation ballot, the SDT will be balloting <b>both</b> FAC-003-3 and FAC-003-X, but stakeholders should <b>not</b> vote as though they are choosing one or the other. As stated above, the SDT plans to present FAC-003-3 alone to NERC’s Board of Trustees, but it wants to have FAC-003-X ready to submit to the Board if, for some reason, neither FAC-003-2 nor FAC-003-3 are approved by FERC. Members of the ballot body should vote on the merits of each version of FAC-003 individually. <b>In other words, stakeholders who support adding GOs to the applicability of FAC-003 should vote in the affirmative for both FAC-003-3 and FAC-003-X.</b></p>		
PSEG Energy Resources & Trade LLC/ Public Service Electric and Gas Co./ PSEG Fossil LLC	Negative	The phrase “generator Facility” should be “generator Transmission Facility,” and the phrase “Transmission System” should be “Transmission system.”
<p><b>Response:</b> Thank you for your comment. We agree with your change to “Transmission system” but not to the addition of “Transmission” in the phrase “generator Facility.” The SDT does not agree with labeling a GO’s Facility as “Transmission,” in part because in some areas (like Texas), GOs, by statute, can’t own Transmission. It was also brought to the SDT’s attention that in most cases, the Facility in question is referred to as the Interconnection Facility in documents filed by the GO with FERC. Therefore, the SDT intentionally modified language so that a Facility owned by a generation entity did not contain the term “Transmission.”</p>		
SERC Reliability Corporation	Negative	There should not be a weak link under the standard. This proposed revision would create a weak-link where a portion of the otherwise covered right-of-way would be exposed.

Organization	Yes or No	Question 10 Comment
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled "<a href="#">Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface</a>," the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: "Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are..."</p>		
<p>New York State Department of Public Service/ National Association of Regulatory Utility Commissioners</p>	<p>Negative</p>	<p>Understand that there is an open issue regarding the availability of generation compliance documentation that needs to be satisfactorily addressed.</p>
<p><b>Response:</b> The SDT does not understand your specific concern.</p>		
<p>Infigen Energy US</p>	<p>Affirmative</p>	<p>Infigen supports the efforts of the SDT to ensure that Protection System Misoperations affecting the reliability of the BES are thoroughly analyzed and mitigated. Generator Owners are already analyzing Misoperations as/if they occur, and are employing Corrective Action Plans to avoid future Misoperations. We support maintaining "reasonable and appropriate" preventative measures and risk assessment tools to ensure that misoperations are evaluated and corrected expediently.</p>
<p><b>Response:</b> Thank you for your comment and support.</p>		
<p>PPL EnergyPlus LLC/PPL NERC Registered Affiliates</p>	<p>Affirmative</p>	<p>PPL Generation, LLC, on behalf of its NERC-registered subsidiaries, appreciates the effort by the Standard Development Team to address the GO-TO interface issues in a manner that enhances the reliability of the BES without adding unnecessary burden on Generators. As registered GOs/GOPs, the PPL Generation registered entities agree with the changes made by the SDT to these three standards. To the extent that GOs/GOPs are required to register as TOs/TOPs, PPL Generation would have</p>

Organization	Yes or No	Question 10 Comment
		significant concerns with meeting the compliance requirements applicable to TOs in the standards included in the scope of this Project, as well as other TO/TOP requirements throughout other NERC standards.
<b>Response:</b> Thank you for your comment and support.		
SERC Reliability Corporation	Affirmative	The Generator Owner may be required to self-certify and report periodically to the region whether they have become applicable to the standard.
<b>Response:</b> Thank you for your comment and support.		
Southwest Transmission Cooperative, Inc./ ACES Power Marketing Standards Collaborators/ ACES Power Marketing	Affirmative	The modifications to PRC-004-2.1 R2 could be interpreted as requiring the GO to analyze Protection System Misoperations on the generator interconnection Facility even if it does not own the Facility. We suggest modifying the requirement as shown below to address this issue.”The Generator Owner shall analyze Protection System Misoperations on its generator and generator interconnection Facility that it owns ...”
<b>Response:</b> Thank you for your comment. The SDT believes that the language makes clear that an entity need only be concerned with the Elements or Facilities that it owns.		
SERC Reliability Corporation	Affirmative	With the understanding the Generator Interconnection FACilities will be grouped with Transmission Protection Systems for analysis at the regional level.
<b>Response:</b> Thank you for your comment and support.		
Entergy Services		We suggest that the Vegetation Management Standards should be consistent for both the TO and GO facilities. We would also like to suggest an additional Recommendation for added clarity regarding Category 3 Outages (Off-ROW Fall-in Outages). We understand that the Category 3 Outages are not a violation of the Standard, but we feel that there should be some level of comment added within the Standard clearly stating that these Outages are “Reportable Only” during the

Organization	Yes or No	Question 10 Comment
		<p>Quarterly Outage reports to the RE's, and that there are no associated violations/sanctions for this Category Of Outage, and that an Off-ROW fall-in outage would not be considered an encroachment into the MVCD in any way. The Technical Reference Document does a good job of clearly stating this in the Introduction on Page 5 ("This standard is not intended to address outages such as those due to vegetation fall-ins or blow-ins from outside the Right-of-Way, vandalism, human activities or acts of nature.") and we feel that this should also be stated clearly in the Standard.</p>
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled "<a href="#">Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface</a>," the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: "Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are..."</p> <p>The remainder of your comment is outside the scope of this SDT.</p>		
Southern Company		<p>We agree with the 2010-17 Standard Drafting Team's conclusion to not modify other standards such as those mentioned on page 4 of the Technical Justification document. In addition, we wish to provide the following support for exclusion of these specific standards. Southern Company believes NERC's Project 2010-07 SDT must challenge making revisions to the standards included in the FERC order on Cedar Creek and Milford. (This order supports NERC's requirement for those entities to register as a TO/TOP due to their ownership of generator interconnection circuits &gt; 100kV.) We believe there are clear technical and reliability-based reasons that support not adding GO and GOP requirements to these standards and not requiring the GO or GOP to register as a TO or TOP. Furthermore, we also believe there are clear distinctions between GO/GOP responsibilities and TO/TOP responsibilities that must be</p>

Organization	Yes or No	Question 10 Comment
		<p>maintained to ensure BES reliability. Revising standards to assign TO/TOP responsibilities to a GO/GOP or requiring a GO/GOP to register as a TO/TOP because of generator interconnection circuits &gt; 100kV will reduce the clarity of these responsibilities. We have provided specific comments on each standard below:</p> <p>EOP-005-1 R1, R2, R6, R7R1 and R2 require each TOP to have and maintain a system restoration plan. R6 requires the TOP to train its operating personnel in implementing this plan. R7 requires the TOP to verify its restoration plan by actual testing or simulation. These requirements are clearly the role and responsibility of the TOP, not a GO/GOP who happens to have generator interconnection facilities in the TOP's control area. The GOP's roles and responsibilities are clearly and appropriately addressed EOP-005-2. The presence of a generator interconnection circuit &gt; 100kV that happens to be owned by the GO instead of the TOP fundamentally does not change the roles and responsibilities of the TOP or the GOP. Thus, no changes due to EOP-005 are needed.</p> <p>FAC-014-2, R2: FAC-014-2 R2 states "The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology." FAC-014-2 R2 should not be revised to include GOPs. The GO is required by FAC-008-1 R1 and FAC-009-1 (FERC approved version) and pending FAC-008-3 R3 and R6 (FAC-008-3 filed with FERC for approval) to document the Facility Ratings for a GO-owned generator interconnection circuit &gt;100kV. The established Facility Rating must respect the most limiting applicable equipment rating in the circuit and must consider operating limitations and ambient conditions. The thermal or ampere rating of this circuit would equal its ampere operating limit and should be conveyed by the GO to the GOP if they are not the same entity. The operating voltage limits for this circuit are established by the applicable TO/TOP, not the GO or GOP. Therefore, we believe adding the GO to FAC-014-2 R2 would be redundant.</p> <p>PER-003-1 R2, R2.1, R2.2PER-003-1 R2 and its sub-requirements state:"R2. Each Transmission Operator shall staff its Real-time operating positions performing</p>

Organization	Yes or No	Question 10 Comment
		<p>Transmission Operator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates (1 ) : [Risk Factor: High][Time Horizon: Real-time Operations]: R2.1. Areas of Competency R2.1.1. Transmission operations R2.1.2. Emergency preparedness and operations R2.1.3. System operations R2.1.4. Protection and control R2.1.5. Voltage and reactive R2.2. Certificates o Reliability Operator o Balancing, Interchange and Transmission Operator o Transmission Operator This requirement is specifically for TOPs. Personnel training for GOPs needs to be addressed separately and not mingled with responsibilities of the TOP. The GOPs role in supporting BES reliability needs to be clearly understood and defined prior to establishing training requirements in the standards.</p> <p>PRC-001-1, R2, R2.2, R4, R6Generator Operators (GOPs) and the scope of protection equipment for generation interconnection Facilities are already appropriately accounted for in this standard in requirement R2 and sub-requirement R2.2 The language used in requirement R2 which applies to the GOP uses the general terms “relay or equipment failures” which would include not only generator relaying, but generator interconnection relaying in the GOPs scope as well. The GOP is required to notify the TOP and Host BA in R2.1 “if a protective relay or equipment failure reduces system reliability.” Requirement R2.2 requires the affected TOP to notify its RC and affected TOPs and BAs. Thus, applying R2.2 to a GOP would be redundant to R2.1. Requirement R4 states, “Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.” A generator interconnection tie line does not constitute a ‘major tie line” or major “interconnection with neighboring GOPs, TOPs, and BAs.” Thus, R4 should not be revised to include GOPs. If a GO exists within NERC that does own such interconnection facilities, the responsibility for coordination of protection systems on such a line or interconnection should be the responsibility of the TOP in that area, not the GO/GOP. This may require formal agreements between the TO/TOP and GO/GOP, since the GO may own protection equipment on his end. The same logic applies to</p>

Organization	Yes or No	Question 10 Comment
		<p>R6. R6 states, “Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.” This is clearly the responsibility of the TOP and/or BA, not a GO/GOP who happens to have generator interconnection facilities in the area. An SPS function by definition is to maintain BES reliability. If a GO/GOP has equipment within the equipment scope of a Special Protection System (SPS), responsibility for monitoring the SPS should be conveyed in a formal agreement as appropriate.</p> <p>TOP-001-1 R1 Requirement R1 states, “Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.” This is clearly the responsibility of the TOP, not a GO/GOP who happens to have generator interconnection facilities in the TOP’s area. Thus, R1 should not be applied to a GO/GOP who owns or operates generator interconnection facilities. Furthermore, TOP-001-1 R3 (proposed to be covered in the future in the proposed IRO-001-2 R2 and R3) appropriately requires the GOP to comply with reliability directives issued by the TO “unless such actions would violate safety, equipment, regulatory or statutory requirements.” These requirements effectively give the TOP the necessary decision-making authority over operation of all generator Facilities up to the point of interconnection. They also give the GOP the necessary authority to take appropriate actions to ensure safety and protection of the GO’s equipment. Thus, no changes to TOP-001-1 are necessary.</p> <p>TOP-004-2 R6, R6.1, R6.2, R6.3, R6.4 Requirement R6 and its sub-requirements state: “R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: R6.1. Monitoring and controlling voltage levels and real and reactive power flows. R6.2. Switching transmission elements. R6.3. Planned outages of transmission elements. R6.4. Responding to IROL and SOL violations.” These are clearly</p>

Organization	Yes or No	Question 10 Comment
		<p>the responsibility of the TOP, not a GO/GOP who happens to have generator interconnection facilities in the TOP’s area. Thus, these requirements should not be applied to a GO/GOP who owns or operates generator interconnection facilities. The same logic applies here as stated above in our discussion on TOP-001-1. We believe it is inappropriate and would be adverse to BES reliability to apply these requirements to a GOP. TOP-004-2 effectively gives the TOP the necessary decision-making authority over operation of all generator Facilities up to the point of interconnection. They also give the GOP the necessary authority to take appropriate actions to ensure safety and protection of the GO’s equipment, such as opening high voltage generator output breakers when required to protect the unit. Thus, no changes to TOP-004-2 are necessary. TOP-006-2 R3 Requirement R3 states, “R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel. The intent of this requirement when applied to a GOP is already addressed in PRC-001-1 R1 which states, “Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.” Thus, no change to TOP-006-2 is necessary. ”</p>
<p><b>Response:</b> Thank you for your comment and support. We agree that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards and not requiring the GO or GOP to register as a TO or TOP. We have expanded our technical justification document (posted under “Supporting Materials”) to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive, and many of your explanations are included therein.</p>		
<p>American Wind Energy Association</p>		<p>AWEA appreciates the opportunity to submit these comments on the NERC Project 2010-07. AWEA supports the general direction indicated by both the Generator Requirements at the Transmission Interface Ad Hoc Group and the Project 2010-07 Standards Development Team. We agree with the sentiments from both groups that a GO or GOP that also owns or operates a generator lead line should not be required to register as a TO or TOP strictly because they own or operate a generator lead line. We also agree that requiring these GO/GOPs to comply with all the TO/TOP standards</p>



Organization	Yes or No	Question 10 Comment
		<p>would have little effect on or benefits to reliability of the Bulk Electric System, and could even detract from it. AWEA supports the intent and goal of the SDT to ensure that all generator-owned Facilities are appropriately covered under NERC’s Reliability Standards. We also agree with the SDT that while many GO/GOPs operate Elements and Facilities that might be considered by some entities to be Transmission, these are most often radial Facilities that are not part of the integrated grid, and as such should not be subject to the same standards applicable to TO/TOPs, who own and operate Transmission Elements and Facilities that are part of the integrated grid. Therefore, we support the SDT’s approach of identifying a very limited number of TO/TOP standards, such as FAC-001 and FAC-003, which should also apply to GO/GOP owners of generator lead lines. We would be concerned, however, if additional requirements were added beyond FAC-001, FAC-003, and PRC-004. Consideration of any additional standards with respect to generator lead lines should be done on a standard-by-standard basis, reviewing the applicability of each standard as well as the impact on the reliability of the Bulk Electric System.</p>
<p><b>Response:</b> Thank you for your comment and support.</p>		
<p>Bonneville Power Administration</p>		<p>BPA thanks you for the opportunity to comment on Project 2010-07, Generator Requirements at the Transmission Interface. BPA stands in support of the proposed revisions and has no comments or concerns at this time.</p>
<p><b>Response:</b> Thank you for your comment and support.</p>		
<p>Constellation Power Source Generation</p>		<p>Constellation appreciates and supports the work of the standard drafting team. We recognize the significant time invested by technical experts from industry to consider the appropriate application of reliability standards to address concerns raised about coverage of transmission at the generator interface. The drafting team analysis identified the standards in need of revision to appropriately address the reliability concerns raised. While the revision process focuses on specific standards, it is important to consider the reliability questions in the context of the full complement</p>

Organization	Yes or No	Question 10 Comment
		<p>of reliability standards that apply to entities. For instance, the following standards already apply to generators and relate to the reliability considerations around transmission at the generator interface:</p> <ul style="list-style-type: none"> <li>o PRC-001-1 addresses coordination of protection system components by requiring all GOs to ensure coordination of their protection system with interconnected parties. Further, FAC-002 requires that all new facilities undergo reviews by the TOP, BA, etc.</li> <li>o PRC-004-1 requires all GOs to ensure that they analyze all misoperations on their protection system which would include the protection of the tie line.</li> <li>o TOP standards applicable to GOs aid coordination between a GO and a TO with regards to the generator tie line by requiring all GOs to coordinate all maintenance and emergency outages (both forced and planned) with all applicable interconnected parties. Further, all ISO procedures require the same of GOs.</li> <li>o RC, TOP and/or BA certified operators control and are responsible for overseeing that transmission. According to the NERC functional model, a Generator Operator is defined as “operat(ing) generating unit(s) and perform(ing) the functions of supplying energy and reliability related services.” Given this limited scope, the Generator Operator (GOP) cannot be considered as operating on the same level as the Reliability Coordinator, Transmission Operator or Balancing Authority when it comes to real time information on the status of the BES. The GOP does not monitor and control the BES, rather the GOP only monitors and controls the generators that it operates and relays information to other operating entities.</li> <li>o IRO and TOP standards applicable to GOs include tie lines in their pool of resources to alleviate operational emergencies by requiring all GOs to operate as directed by their TOP, BA, or RC as directed and must render emergency assistance.</li> <li>o FAC-8 and FAC-9 manage rating methodology consistency by requiring all GOs to develop a methodology to rate all equipment, and that the RC has the authority to challenge the GO on that methodology. The onus is on the GO to either change their methodology and rating accordingly, or provide a technical justification as to why</li> </ul>

Organization	Yes or No	Question 10 Comment
		they cannot adopt the changes. Further, a generator will never be limited by its tie line, as a generator’s profits are directly tied to its output. Therefore no generator would limit its facility to the equipment that is delivering that output.
<p><b>Response:</b> Thank you for your comment and support. We agree that it is important to consider the reliability questions in the context of the full complement of reliability standards, and we have endeavored to make these broader connections clear in our revised technical justification document (posted under “Supporting Materials”). That document has been expanded to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive, and the kinds of further justifications you also provided are included therein. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.</p>		
Cowlitz County PUD		In answer to the SDT request for feedback on FERC's Order concerning Cedar Creek and Milford, the District finds no technical reason to add any of the listed standard requirements, and struggles to understand why FERC would even consider this listing as applicable.
<p><b>Response:</b> Thank you for your comment and support.</p>		
Southwest Transmission Cooperative, Inc.		In section 4.2.1 of the Applicability Section, “within” should be “with”. Because NERC’s Glossary of Terms establishes that an Agreement can be verbal and not enforceable by law, section 4.2.1 should be further modified to clarify that it is a legally enforceable and fully executed Agreement. The language in R3 in parenthesis after Generation Owner should be modified to “once required by Requirement R2”. This makes it clearer that R3 does not apply until the GO has an executed Agreement to evaluate a request by a third part to interconnect.
<p><b>Response:</b> Thank you for your comment. We agree that “within” should be “with.” The SDT chose not to adopt the second recommendation as the requirement already contains the term “executed.” The SDT also chose not to adopt the third recommendation as the requirement already contains the parenthetical (in accordance with Requirement R2) which we feel is synonymous with the comment.</p>		

Organization	Yes or No	Question 10 Comment
Manitoba Hydro		Manitoba Hydro would also like to point out that if the redline changes are implemented, it will greatly increase the complexity of coordination required under FAC-002-1 for Transmission Planners/Planning Authorities.
<p><b>Response:</b> Thank you for your comment. The SDT agrees this is a complex issue and did its best to outline how it arrived at its position in the document titled "<a href="#">Technical Justification: FAC-001-1.</a>"</p>		
Compliance & Responsibility Organization		<p>NextEra Energy, Inc. (NextEra) appreciates the work of the Project 2010-07 Generator Requirements at the Transmission Interface Standard Drafting Team (SDT) on a subject that NextEra has a significant interest in resolving. In fact, NextEra has been a member of the SDT and an active observer. Given the recent events - such as (a) the North American Electric Reliability Commission's draft interim directive; (b) the denial of the Milford and Cedar Cheek requests for reconsideration at the Federal Energy Regulatory Commission (FERC) and (c) the record in this case which, at times, suggests the SDT needs to more formally consider the Milford and Cedar Cheek Reliability Standards - NextEra requests that SDT more formally consider the merits of each Reliability Standard adopted the Milford and Cedar Cheek FERC orders and the NERC draft interim directive. Although NextEra does not condone the manner in which NERC issued the interim draft directive and stated so in its comments to NERC on the interim draft directive, NextEra's overarching objective on this issue is to bring a uniform, fair and technically supported approach that resolves the interface issue. Thus, NextEra requests that the SDT (prior to proceeding any further or any additional comments or votes on specific draft Reliability Standards) issue a technical paper that point-by-point addresses the merits of including the Reliability Standards set forth in the FERC Orders and NERC's draft interim directive, and request stakeholder, including NERC staff, comment. For example, this technical paper would likely the merits of NERC's draft interim directive not requiring NERC-certified operators (but require training of interface operators), while FERC's orders require NERC-certified operators. While NextEra does not agree five days of training is necessary for an interface operator, as the draft interim directive appears to propose, NextEra does</p>

Organization	Yes or No	Question 10 Comment
		<p>believe a technical case can be made why NERC-certification is not required, and that some degree of training related to the applicable Reliability Standards is reasonable. Similar, on FAC-003 (as well as several other Standards), the draft interim directive proposes a slightly different approach than the SDT. NextEra would rather these approaches reconciled than be in conflict, with the potential for continued conflict as the SDT's work product proceeds. Further, NextEra requests that the SDT's review the technical merits of NERC's proposed criteria to determine what generator transmission lead is required to comply with additional Reliability Standards. As noted, above, this technical paper should be posted for stakeholder, including NERC staff, comment. Accordingly, while NextEra would have preferred that NERC and the Regional Entities express there interim draft directive approach on the record in this proceeding, NextEra believes it is appropriate for the SDT to draft a comprehensive technical paper that, with an open approach, considers the inclusion of additional Reliability Standards, if appropriate, as a way of building lasting support for its approach.</p>
<p><b>Response:</b> Thank you for your comment and support. We certainly agree that is important for NERC staff and the SDT to continue to work together to try to develop a mutually agreed upon solution for dealing with this reliability gap, and to a certain extent, the SDT has tried to provide the kind of technical paper you suggest in its modified technical justification document (posted under "Supporting Materials"), which has been expanded to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. The SDT does not, at this point, plan to develop a technical paper that discusses the merits of the standards introduced by FERC and NERC, because its current focus is on filing the FAC-001-1, FAC-003-3, and PRC-004-2.1a with FERC. As it moves forward to a final solution, however, this kind of technical paper may prove useful. We appreciate the suggestion.</p>		
Dominion		No
Tennessee Valley Authority		No
Exelon		<p>PRC-004 - suggest that the Standard state that responsibility for the analysis of missoperations of protective equipment shall be the responsibility of the owner of the protective equipment.</p>

Organization	Yes or No	Question 10 Comment
<p><b>Response:</b> Thank you for your comment and support. The SDT believes that the language makes clear that an entity need only be concerned with the Elements or Facilities that it owns.</p>		
ReliabilityFirst		<p>ReliabilityFist has found a number of editorial erros for the FAC-001-1 VSLs. They include the following:1. VSL R1 - should not reference sub-requirements, should reference the sub-parts consistent with the requirement (i.e. Requirement R1, Part 1.1, 1.2 or 1.3) 2. VSL for R3 - the VSL should referenced Requirement 3, Part 3.1.1 through 3.1.16 rather than what is currently stated (Requirement R3, Part 3.1.1 R3.1.6)</p>
<p><b>Response:</b> Thank you for your comment. While we agree that the VSLs for R1 need to be updated, that change is outside the scope of this SDT because our changes are limited to those that incorporate the GO into the applicability of the requirement; the team made no changes to R1 as it only includes the TO. We have, however, made the suggested changes to the VSLs for R3.</p>		
RES Americas Development		<p>RES and AWEA appreciates the opportunity to submit these comments on the NERC Project 2010-07. We support the general direction indicated by both the Generator Requirements at the Transmission Interface Ad Hoc Group and the Project 2010-07 Standards Development Team. We agree with the sentiments from both groups that a GO or GOP that also owns or operates a generator lead line should not be required to register as a TO or TOP strictly because they own or operate a generator lead line. We also agree that requiring these GO/GOPs to comply with all the TO/TOP standards would have little effect on or benefits to reliability of the Bulk Electric System, and could even detract from it. RES and AWEA supports the intent and goal of the SDT to ensure that all generator-owned Facilities are appropriately covered under NERC’s Reliability Standards. We also agree with the SDT that while many GO/GOPs operate Elements and Facilities that might be considered by some entities to be Transmission, these are most often radial Facilities that are not part of the integrated grid, and as such should not be subject to the same standards applicable to TO/TOPs, who own and operate Transmission Elements and Facilities that are part of the integrated grid. Therefore, we support the SDT’s approach of identifying a very limited number of</p>

Organization	Yes or No	Question 10 Comment
		TO/TOP standards, such as FAC-001 and FAC-003, which should also apply to GO/GOP owners of generator lead lines. We would be concerned, however, if additional requirements were added beyond FAC-001, FAC-003, and PRC-004. Consideration of any additional standards with respect to generator lead lines should be done on a standard-by-standard basis, reviewing the applicability of each standard as well as the impact on the reliability of the Bulk Electric System.
Sempra Generation		Sempra Generation also supports the comments, being concurrently filed, of the Electric Power Supply Association (EPSA).
<b>Response:</b> Thank you for your comment and support.		
Puget Sound Energy, Inc.		The changes to this standard are minor, and seem to be centered around including "generator Interconnection facilities" to R2. This added phrase and the statement in 1.4 Data Retention "Generator Owner that owns a generation Protection System" seems to assume that the generator owner and generator interconnection facilities owner is always the same. This is not always the case, and will make this standard language confusing to prepare evidence for. A suggestion would be to revise the language to allow for a separate generator owner and generator interconnection facilities owner.
<b>Response:</b> Thank you for your comment and support. The SDT believes that the language makes clear that an entity need only be concerned with the Elements or Facilities that it owns.		
SERC Planning Standards Subcommittee/ SERC OC Standards Review Group		The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers”
<b>Response:</b> Thank you for your comment and support.		

END OF REPORT



## A. Introduction

1. **Title:** **Facility Connection Requirements**
2. **Number:** FAC-001-1
3. **Purpose:** To avoid adverse impacts on reliability, Transmission Owners and Generator Owners must establish Facility connection and performance requirements.
4. **Applicability:**
  - 4.1. Transmission Owner
  - 4.2. Applicable Generator Owner
    - 4.2.1 Generator Owner with an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems.
5. **Effective Date:**
  - 5.1. In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner and Regional Entity become effective upon Board of Trustees' adoption.
  - 5.2. In those jurisdictions where regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities. In those jurisdictions where no regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after Board of Trustees' adoption.

## B. Requirements

- R1. The Transmission Owner shall document, maintain, and publish Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, 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:
  - 1.1. Generation Facilities,
  - 1.2. Transmission Facilities, and
  - 1.3. End-user Facilities

*[VRF – Medium]*
- R2. Each applicable Generator Owner shall, within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems (under FAC-002-1), document and publish its Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, subregional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements.

*[VRF – Medium]*

- R3.** Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) shall address the following items in its Facility connection requirements:
- 3.1.** Provide a written summary of its plans to achieve the required system performance as described in Requirements R1 or R2 throughout the planning horizon:
- 3.1.1.** Procedures for coordinated joint studies of new Facilities and their impacts on the interconnected Transmission systems.
  - 3.1.2.** Procedures for notification of new or modified Facilities to others (those responsible for the reliability of the interconnected Transmission systems) as soon as feasible.
  - 3.1.3.** Voltage level and MW and MVAR capacity or demand at point of connection.
  - 3.1.4.** Breaker duty and surge protection.
  - 3.1.5.** System protection and coordination.
  - 3.1.6.** Metering and telecommunications.
  - 3.1.7.** Grounding and safety issues.
  - 3.1.8.** Insulation and insulation coordination.
  - 3.1.9.** Voltage, Reactive Power, and power factor control.
  - 3.1.10.** Power quality impacts.
  - 3.1.11.** Equipment Ratings.
  - 3.1.12.** Synchronizing of Facilities.
  - 3.1.13.** Maintenance coordination.
  - 3.1.14.** Operational issues (abnormal frequency and voltages).
  - 3.1.15.** Inspection requirements for existing or new Facilities.
  - 3.1.16.** Communications and procedures during normal and emergency operating conditions.

*[VRF – Medium]*

- R4.** 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, the Regional Entity, and ERO on request (five business days).

*[VRF – Medium]*

## **C. Measures**

- M1.** The Transmission Owner shall make available (to its Compliance Enforcement Authority) evidence that it met all the requirements stated in Requirement R1.

- M2.** Each Generator Owner that has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems shall make available (to its Compliance Enforcement Authority) evidence that it met all requirements stated in Requirement R2.
- M3.** Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) shall make available (to its Compliance Enforcement Authority) evidence that it met all requirements stated in Requirement R3.
- M4.** The Transmission Owner shall make available (to its Compliance Enforcement Authority) evidence that it met all the requirements stated in Requirement R4.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

Compliance Monitor: Regional Entity

**1.2. Compliance Monitoring and Enforcement Processes:**

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

**1.3. Data Retention**

The Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Owner shall retain evidence of Requirement R1, Measure M1, Requirement R3, Measure M3, and Requirement R4, Measure M4 from its last audit.

The Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain evidence of Requirement R2, Measure M2, and Requirement R3, Measure M3 from its last audit.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Additional Compliance Information**

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Not Applicable.	<p>The Transmission Owner failed to do one of the following:</p> <p>Document or maintain or publish Facility connection requirements as specified in the Requirement</p> <p>OR</p> <p>Failed to include one (1) of the components as specified in R1.1, R1.2 or R1.3.</p>	<p>The Transmission Owner failed to do one of the following:</p> <p>Failed to include (2) of the components as specified in R1.1, R1.2 or R1.3</p> <p>OR</p> <p>Failed to document or maintain or publish its Facility connection requirements as specified in the Requirement <b>and</b> failed to include one (1) of the components as specified in R1.1, R1.2 or R1.3.</p>	The Transmission Owner did not develop Facility connection requirements.
R2	The Generator Owner failed to document and publish Facility connection requirements until more than 45 calendar days but less than or equal to 60 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the interconnected Transmission systems.	The Generator Owner failed to document and publish Facility connection requirements until more than 60 calendar days but less than or equal to 70 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the interconnected Transmission systems.	The Generator Owner failed to document and publish Facility connection requirements until more than 70 calendar days but less than or equal to 80 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the interconnected Transmission systems.	The Generator Owner failed to document and publish Facility connection requirements until more than 80 days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the interconnected Transmission systems.
R3	The responsible entity’s Facility connection	The responsible entity’s Facility connection	The responsible entity’s Facility connection	The responsible entity’s Facility connection

	requirements failed to address one of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.	requirements failed to address two of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.	requirements failed to address three of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.	requirements failed to address four or more of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.
R4	The responsible entity made the requirements available more than five business days but less than or equal to 10 business days after a request.	The responsible entity made the requirements available more than 10 business days but less than or equal to 20 business days after a request.	The responsible entity made the requirements available more than 20 business days less than or equal to 30 business days after a request.	The responsible entity made the requirements available more than 30 business days after a request.

**E. Regional Differences**

1. None identified.

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	TBD	Added requirements for Generator Owner and brought overall standard format up to date.	Revision under Project 2010-07

## A. Introduction

1. **Title:** **Facility Connection Requirements**
2. **Number:** FAC-001-1
3. **Purpose:** To avoid adverse impacts on reliability, Transmission Owners and Generator Owners must establish Facility connection and performance requirements.
4. **Applicability:**
  - 4.1. Transmission Owner
  - 4.2. Applicable Generator Owner
    - 4.2.1 Generator Owner with an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission sSystems.
5. **Effective Date:**
  - 5.1. In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner and Regional Entity become effective upon Board of Trustees' adoption.
  - 5.2. In those jurisdictions where regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities. In those jurisdictions where no regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after Board of Trustees' adoption.

## B. Requirements

- R1. The Transmission Owner shall document, maintain, and publish Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, 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:
  - 1.1. Generation Facilities,
  - 1.2. Transmission Facilities, and
  - 1.3. End-user Facilities

*[VRF – Medium]*
- R2. Each applicable Generator Owner shall, within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission sSystems (under FAC-002-1), document and publish its Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, subregional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements.

*[VRF – Medium]*

- R3.** Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) shall address the following items in its Facility connection requirements:
- 3.1.** Provide a written summary of its plans to achieve the required system performance as described in Requirements R1 or R2 throughout the planning horizon:
- 3.1.1.** Procedures for coordinated joint studies of new Facilities and their impacts on the interconnected Transmission ~~s~~Systems.
  - 3.1.2.** Procedures for notification of new or modified Facilities to others (those responsible for the reliability of the interconnected Transmission ~~s~~Systems) as soon as feasible.
  - 3.1.3.** Voltage level and MW and MVAR capacity or demand at point of connection.
  - 3.1.4.** Breaker duty and surge protection.
  - 3.1.5.** System protection and coordination.
  - 3.1.6.** Metering and telecommunications.
  - 3.1.7.** Grounding and safety issues.
  - 3.1.8.** Insulation and insulation coordination.
  - 3.1.9.** Voltage, Reactive Power, and power factor control.
  - 3.1.10.** Power quality impacts.
  - 3.1.11.** Equipment Ratings.
  - 3.1.12.** Synchronizing of Facilities.
  - 3.1.13.** Maintenance coordination.
  - 3.1.14.** Operational issues (abnormal frequency and voltages).
  - 3.1.15.** Inspection requirements for existing or new Facilities.
  - 3.1.16.** Communications and procedures during normal and emergency operating conditions.

*[VRF – Medium]*

- R4.** 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, the Regional Entity, and ERO on request (five business days).

*[VRF – Medium]*

## C. Measures

- M1.** The Transmission Owner shall make available (to its Compliance Enforcement Authority) evidence that it met all the requirements stated in Requirement R1.

- M2.** Each Generator Owner that has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission sSystems shall make available (to its Compliance Enforcement Authority) evidence that it met all requirements stated in Requirement R2.
- M3.** Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) shall make available (to its Compliance Enforcement Authority) evidence that it met all requirements stated in Requirement R3.
- M4.** The Transmission Owner shall make available (to its Compliance Enforcement Authority) evidence that it met all the requirements stated in Requirement R4.

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Compliance Monitor: Regional Entity

#### 1.2. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

#### 1.3. Data Retention

The Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Owner shall retain evidence of Requirement R1, Measure M1, Requirement R3, Measure M3, and Requirement R4, Measure M4 from its last audit.

The Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain evidence of Requirement R2, Measure M2, and Requirement R3, Measure M3 from its last audit.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.4. Additional Compliance Information

None.



2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Not Applicable.	<p>The Transmission Owner failed to do one of the following:</p> <p>Document or maintain or publish Facility connection requirements as specified in the Requirement</p> <p>OR</p> <p>Failed to include one (1) of the components as specified in R1.1, R1.2 or R1.3.</p>	<p>The Transmission Owner failed to do one of the following:</p> <p>Failed to include (2) of the components as specified in R1.1, R1.2 or R1.3</p> <p>OR</p> <p>Failed to document or maintain or publish its Facility connection requirements as specified in the Requirement <b>and</b> failed to include one (1) of the components as specified in R1.1, R1.2 or R1.3.</p>	The Transmission Owner did not develop Facility connection requirements.
R2	The Generator Owner failed to document and publish Facility connection requirements until more than 45 calendar days but less than or equal to 60 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the <u>interconnected</u> Transmission <u>sSystems</u> .	The Generator Owner failed to document and publish Facility connection requirements until more than 60 calendar days but less than or equal to 70 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the <u>interconnected</u> Transmission <u>sSystems</u> .	The Generator Owner failed to document and publish Facility connection requirements until more than 70 calendar days but less than or equal to 80 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the <u>interconnected</u> Transmission <u>sSystems</u> .	The Generator Owner failed to document and publish Facility connection requirements until more than 80 days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the <u>interconnected</u> Transmission <u>sSystems</u> .
R3	The responsible entity’s Facility connection	The responsible entity’s Facility connection	The responsible entity’s Facility connection	The responsible entity’s Facility connection

	requirements failed to address one of the <u>pParts</u> listed in Requirement R3, <u>pParts 3.1.1 through R3.1.16.</u>	requirements failed to address two of the <u>parts listed in Requirement R3, parts 3.1.1 through 3.1.16.</u> <u>Parts listed in Requirement R3, Part 3.1.1 R3.1.6.</u>	requirements failed to address three of the <u>parts listed in Requirement R3, parts 3.1.1 through 3.1.16.</u> <u>Parts listed in Requirement R3, Part 3.1.1 R3.1.6.</u>	requirements failed to address four or more of the <u>parts listed in Requirement R3, parts 3.1.1 through 3.1.16.</u> <u>Parts listed in Requirement R3, Part 3.1.1 R3.1.6.</u>
R4	The responsible entity made the requirements available more than five business days but less than or equal to 10 business days after a request.	The responsible entity made the requirements available more than 10 business days but less than or equal to 20 business days after a request.	The responsible entity made the requirements available more than 20 business days less than or equal to 30 business days after a request.	The responsible entity made the requirements available more than 30 business days after a request.

**E. Regional Differences**

1. None identified.

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	TBD	Added requirements for Generator Owner and brought overall standard format up to date.	Revision under Project 2010-07

**B.A. Introduction**

1. **Title:** Facility Connection Requirements
2. **Number:** FAC-001-~~0~~1
3. **Purpose:**- To avoid adverse impacts on reliability, Transmission Owners and Generator Owners must establish ~~facility~~Facility connection and performance requirements.
4. **Applicability:**
  - 4.1. Transmission Owner
  - 4.2. Applicable Generator Owner
    - 4.2.1 Generator Owner with an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems.
5. **Effective Date:**—~~April 1, 2005~~
  - 5.1. In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner and Regional Entity become effective upon Board of Trustees' adoption.
  - 5.2. In those jurisdictions where regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities. In those jurisdictions where no regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after Board of Trustees' adoption.

**C.B. Requirements**

- R1. The Transmission Owner shall document, maintain, and publish ~~facility~~Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional ~~Reliability Organization~~Entity, subregional, Power Pool, and individual Transmission Owner planning criteria and ~~facility~~Facility connection requirements. The Transmission Owner's ~~facility~~Facility connection requirements shall address connection requirements for:
  - R1.1.1.1. Generation ~~facilities~~Facilities,
  - R1.2.1.2. Transmission ~~facilities~~Facilities, and
  - R1.3.1.3. End-user ~~facilities~~Facilities
- ~~R2. The Transmission Owner's facility connection requirements shall address, but are not limited to, the following items:  
[VRF – Medium]~~
- R2. Each applicable Generator Owner shall, within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems (under FAC-002-1), document and publish its Facility connection requirements to

ensure compliance with NERC Reliability Standards and applicable Regional Entity, subregional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements.

*[VRF – Medium]*

**R3.** Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) shall address the following items in its Facility connection requirements:

**R2.1.3.1.** Provide a written summary of its plans to achieve the required system performance as described ~~above~~ in Requirements R1 or R2 throughout the planning horizon:

**R2.1.1.3.1.1.** Procedures for coordinated joint studies of new ~~faeilities~~Facilities and their impacts on the interconnected ~~transmission~~Transmission systems.

**R2.1.2.3.1.2.** Procedures for notification of new or modified ~~faeilities~~Facilities to others (those responsible for the reliability of the interconnected ~~transmission~~Transmission systems) as soon as feasible.

**R2.1.3.3.1.3.** Voltage level and MW and MVAR capacity or demand at point of connection.

**R2.1.4.3.1.4.** Breaker duty and surge protection.

**R2.1.5.3.1.5.** System protection and coordination.

**R2.1.6.3.1.6.** Metering and telecommunications.

**R2.1.7.3.1.7.** Grounding and safety issues.

**R2.1.8.3.1.8.** Insulation and insulation coordination.

**R2.1.9.3.1.9.** Voltage, Reactive Power, and power factor control.

**R2.1.10.3.1.10.** Power quality impacts.

**R2.1.11.3.1.11.** Equipment Ratings.

**R2.1.12.3.1.12.** Synchronizing of ~~faeilities~~Facilities.

**R2.1.13.3.1.13.** Maintenance coordination.

**R2.1.14.3.1.14.** Operational issues (abnormal frequency and voltages).

**R2.1.15.3.1.15.** Inspection requirements for existing or new ~~faeilities~~Facilities.

**R2.1.16.3.1.16.** Communications and procedures during normal and emergency operating conditions.

*[VRF – Medium]*

**R3-R4.** The Transmission Owner shall maintain and update its ~~faeility~~Facility connection requirements as required. - The Transmission Owner shall make documentation of these requirements available to the users of the transmission system, the Regional ~~Reliability Organization~~Entity, and ~~NERC~~ERO on request (five business days).

[VRF – Medium]

#### D.C. Measures

- M1.** The Transmission Owner shall make available (to its Compliance ~~Monitor~~) for inspection Enforcement Authority evidence that it met all the requirements stated in Reliability Standard FAC-001-0-Requirement R1.
- M2.** ~~The~~Each Generator Owner that has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission ~~Owners~~systems shall make available (to its Compliance ~~Monitor~~) for inspection Enforcement Authority evidence that it met all requirements stated in Reliability Standard FAC-001-0-Requirement R2.
- M3.** ~~The~~Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) shall make available (to its Compliance ~~Monitor~~) for inspection Enforcement Authority evidence that it met all ~~the~~ requirements stated in Reliability Standard FAC-001-0-R3 Requirement R3.
- M3.M4.** The Transmission Owner shall make available (to its Compliance Enforcement Authority) evidence that it met all the requirements stated in Requirement R4.

#### E.D. Compliance

##### **1. Compliance Monitoring Process**

###### **1.1. Compliance ~~Monitoring Responsibility~~ Enforcement Authority**

Compliance Monitor: Regional ~~Reliability Organization~~Entity

###### **1.2. Compliance Monitoring ~~Period~~ and ~~Reset Timeframe~~ Enforcement Processes:**

~~On request (five business days):~~

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

###### **1.3. Data Retention**

~~None specified:~~

The Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Owner shall retain evidence of Requirement R1, Measure M1, Requirement R3, Measure M3, and Requirement R4, Measure M4 from its last audit.

The Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain evidence of Requirement R2, Measure M2, and Requirement R3, Measure M3 from its last audit.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Additional Compliance Information**

None.

**2. Violation Severity 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.~~

<u>R #</u>	<u>Lower VSL</u>	<u>Moderate VSL</u>	<u>High VSL</u>	<u>Severe VSL</u>
<u>R1</u>	<u>Not Applicable.</u>	<u>The Transmission Owner failed to do one of the following:</u>  <u>Document or maintain or publish Facility connection requirements as specified in the Requirement</u>  <u>OR</u>  <u>Failed to include one</u>	<u>The Transmission Owner failed to do one of the following:</u>  <u>Failed to include (2) of the components as specified in R1.1, R1.2 or R1.3</u>  <u>OR</u>  <u>Failed to document or maintain or publish its Facility connection</u>	<u>The Transmission Owner did not develop Facility connection requirements.</u>

		<u>(1) of the components as specified in R1.1, R1.2 or R1.3.</u>	<u>requirements as specified in the Requirement and failed to include one (1) of the components as specified in R1.1, R1.2 or R1.3.</u>	
<u>R2</u>	<u>The Generator Owner failed to document and publish Facility connection requirements until more than 45 calendar days but less than or equal to 60 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems.</u>	<u>The Generator Owner failed to document and publish Facility connection requirements until more than 60 calendar days but less than or equal to 70 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems.</u>	<u>The Generator Owner failed to document and publish Facility connection requirements until more than 70 calendar days but less than or equal to 80 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems.</u>	<u>The Generator Owner failed to document and publish Facility connection requirements until more than 80 days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems.</u>
<u>R3</u>	<u>The responsible entity's Facility connection requirements failed to address one of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.</u>	<u>The responsible entity's Facility connection requirements failed to address two of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.</u>	<u>The responsible entity's Facility connection requirements failed to address three of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.</u>	<u>The responsible entity's Facility connection requirements failed to address four or more of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.</u>
<u>R4</u>	<u>The responsible entity made the requirements available more than five business days but less than or equal to 10 business days after a request.</u>	<u>The responsible entity made the requirements available more than 10 business days but less than or equal to 20 business days after a request.</u>	<u>The responsible entity made the requirements available more than 20 business days less than or equal to 30 business days after a request.</u>	<u>The responsible entity made the requirements available more than 30 business days after a request.</u>

P.E. Regional Differences

1. None identified.

### Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
<u>1</u>	<u>TBD</u>	<u>Added requirements for Generator Owner and brought overall standard format up to date.</u>	<u>Revision under Project 2010-07</u>

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## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary. When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.*

### **Right-of-Way (ROW)**

A corridor of land on which electric lines may be located. The applicable Transmission Owner or applicable Generator Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

The current glossary definition of this NERC term was modified to include applicable Generator Owners.

In November 2011, NERC’s Board of Trustees adopted FAC-003-2 – Transmission Vegetation Management (developed under Project 2007-07 Vegetation Management). Based on this approval, NERC staff will file FAC-003-2 with the applicable regulatory authorities. The Project 2010-07 SDT will move forward with ballots for both FAC-003-3 (proposed changes to the BOT-adopted FAC-003-2) and FAC-003-X (proposed changes to the FERC-approved FAC-003-1) with the intention of eventually only filing FAC-003-3. The SDT has elected to carry FAC-003-X through to ballot because if FAC-003-2 and FAC-003-3 are not approved by FERC, the SDT wants to be ready to file FAC-003-X to ensure that there is a functional entity responsible for managing vegetation on the piece of line commonly known as the generator interconnection Facility.

**A. Introduction**

**1. Title: Transmission Vegetation Management Program**

**2. Number: FAC-003-X**

**3. Purpose:** To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation-related outages of the transmission systems to the respective Regional Entity and the North American Electric Reliability Council (NERC).

Within the text of NERC Reliability Standard FAC-003-X, “transmission line(s)” and “applicable line(s)” can also refer to the generation Facilities as referenced in 4.4 and its subsections.

**4. Applicability:**

**4.1. Regional Entity.**

**4.2. Applicable Transmission Owner**

**4.2.1.** Transmission Owner that owns overhead transmission lines operated at 200 kV and above and to any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.

**4.3. Applicable Generator Owner**

**4.3.1.** Generator Owner that owns an overhead transmission line(s) that extends greater than one mile (1.609 kilometers) beyond the fenced area of the generating station switchyard up to the point of interconnection with a Transmission Owner’s Facility or does not have a clear line of sight from the switchyard fence to the point of interconnection and is operated at 200 kV and above, and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.

With the line of sight reference in 4.3.1, the SDT simply seeks to clarify the exception language based on the intent that has been agreed upon by the stakeholder body. In its [Consideration of Comments report](#) from the last formal comment period, which ended on July 17, 2011, the SDT explained “We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor.” With the addition of an explicit line of sight reference here, the SDT believes it has clarified its original intent.

**5. Effective Dates:**

There are three effective dates associated with this implementation plan:

The first effective date applies to Transmission Owners.

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner become effective upon Board of Trustees' adoption.

The second effective date allows Generator Owners time to prepare a formal transmission vegetation management program as outlined in Requirement R1.

In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R1 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The third effective date allows entities time to comply with Requirements R2, R3, and R4.

In those jurisdictions where regulatory approval is required, Requirements R2, R3, and R4 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R2, R3, and R4 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

## **B. Requirements**

**R1.** Each applicable Transmission Owner or applicable Generator Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the applicable Transmission Owner's or applicable Generator Owner's objectives, practices, approved procedures, and work specifications<sup>1</sup>.

**R1.1.** The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the applicable Transmission Owner's or applicable Generator Owner's transmission lines.

**R1.2.** Each applicable Transmission Owner or applicable Generator Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the applicable Transmission Owner or applicable Generator Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.

**R1.2.1.** Clearance 1 — The applicable Transmission Owner or applicable Generator Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the applicable

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<sup>1</sup> ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.

Transmission Owner or applicable Generator Owner plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.

**R1.2.2.** Clearance 2 — The applicable Transmission Owner or applicable Generator Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These applicable Transmission Owner-specific or applicable Generator Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.

**R1.2.2.1** Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.

**R1.2.2.2** Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.

**R1.3.** All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner or Generator Owner, to perform their duties.

**R1.4.** Each applicable Transmission Owner or applicable Generator Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner or applicable Generator Owner is restricted from attaining the clearances specified in Requirement 1.2.1.

**R1.5.** Each Transmission Owner or applicable Generator Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.

[VRF – High]

**R2.** Each applicable Transmission Owner or applicable Generator Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or

regulatory authorities. Each applicable Transmission Owner or applicable Generator Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.

*[VRF – High]*

- R3.** Each applicable Transmission Owner or applicable Generator Owner shall report quarterly to its Regional Entity, or the Regional Entity’s designee, sustained transmission line outages determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation.
- R3.1.** Multiple sustained 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.
- R3.2.** The applicable Transmission Owner or applicable Generator Owner is not required to report to the Regional Entity, or the Regional Entity’s designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).
- R3.3.** The outage information provided by the applicable Transmission Owner or applicable Generator Owner to the Regional Entity, or the Regional Entity’s designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.
- R3.4.** An outage shall be categorized as one of the following:
- R3.4.1.** Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;
  - R3.4.2.** Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;
  - R3.4.3.** Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.

*[VRF – Lower]*

- R4.** The Regional Entity shall report the outage information provided to it by applicable Transmission Owners or applicable Generator Owners, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported outages.

*[VRF – Lower]*

**C. Measures**

- M1.** Each applicable Transmission Owner or applicable Generator Owner has a documented TVMP, as identified in Requirement 1.
  - M1.1.** Each applicable Transmission Owner or applicable Generator Owner has documentation that the applicable Transmission Owner or applicable Generator Owner performed the vegetation inspections as identified in Requirement 1.1.
  - M1.2.** Each applicable Transmission Owner or applicable Generator Owner has documentation that describes the clearances identified in Requirement 1.2.
  - M1.3.** Each applicable Transmission Owner or applicable Generator Owner has documentation that the personnel directly involved in the design and implementation of the applicable Transmission Owner's or applicable Generator Owner TVMP hold the qualifications identified by the Transmission Owner or applicable Generator Owner as required in Requirement 1.3.
  - M1.4.** Each applicable Transmission Owner or applicable Generator Owner has documentation that it has identified any areas not meeting the applicable Transmission Owner's or applicable Generator Owner's standard for vegetation management and any mitigating measures the Transmission Owner or applicable Generator Owner has taken to address these deficiencies as identified in Requirement 1.4.
  - M1.5.** Each applicable Transmission Owner or applicable Generator Owner has a documented process for the immediate communication of imminent threats by vegetation as identified in Requirement 1.5.
- M2.** Each applicable Transmission Owner or applicable Generator Owner has documentation that the Transmission Owner implemented the work plan identified in Requirement 2.
- M3.** Each applicable Transmission Owner or applicable Generator Owner has documentation that it has supplied quarterly outage reports to the Regional Entity, or the Regional Entity's designee, as identified in Requirement 3.
- M4.** The Regional Entity has documentation that it provided quarterly outage reports to NERC as identified in Requirement 4.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

Compliance Monitor:

- Regional Entity for the Transmission Owner and Generator Owner
- Electric Reliability Organization or another Regional Entity approved by the ERO and FERC or other applicable government authorities

**1.2. Compliance Monitoring and Enforcement Processes:**

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

**1.3. Data Retention**

The applicable Transmission Owner and applicable Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The applicable Transmission Owner and applicable Generator Owner shall retain evidence of Requirement 1, Measure 1, Requirement 2, Measure 2, and Requirement 3, Measure 3 from its last audit.

**1.4. Additional Compliance Information**

None.

**2. Violation Severity Levels**

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity did not include and keep current one of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current two of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current three of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current all required elements of the TVMP, as directed by the requirement.
R1.1	N/A	N/A	The applicable entity TVMP did not define a schedule, as directed by the requirement, or the type of ROW vegetation inspections, as directed by the requirement.	The applicable entity TVMP did not define a schedule, as directed by the requirement, nor the type of ROW vegetation inspections, as directed by the requirement.
R1.2	N/A	N/A	N/A	The responsible entity, in its TVMP, failed to identify and document clearances between vegetation and any overhead, ungrounded supply conductors.  OR  The responsible entity, in its

				<p>TVMP, failed to take into consideration transmission line voltage, or the effects of ambient temperature on conductor sag under maximum design loading, or the effects of wind velocities on conductor sway.</p> <p>OR</p> <p>The responsible entity, in its TVMP, failed to establish Clearance 1 or Clearance 2 values.</p>
R1.2.1	N/A	N/A	N/A	<p>The responsible entity failed to determine and document an appropriate clearance distance to be achieved at the time of transmission vegetation management work taking into account local conditions and the expected time frame in which the responsible entity expects to return for future vegetation management work.</p> <p>OR</p> <p>The responsible entity documented a Clearance 1 value that was smaller than its</p>



				Clearance 2 value.
R1.2.2	N/A	N/A	N/A	The responsible entity failed to determine and document Clearance 2 values taking into account local conditions and the expected time frame in which the responsible entity expects to return for future vegetation management work.
R1.2.2.1	N/A	N/A	N/A	Where transmission system transient overvoltage factors were known, clearances were not derived from Table 5, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.
R1.2.2.2	N/A	N/A	N/A	Where transmission system transient overvoltage factors are known, clearances were not derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.
R1.3	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, one of those persons did not hold appropriate	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, two of those persons did not hold appropriate	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, three of those persons did not hold appropriate	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, more than three of those persons did not hold appropriate

	qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, 5% or less of those persons did not hold appropriate qualifications and training to perform their duties.	qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 5% up to (and including) 10% of those persons did not hold appropriate qualifications and training to perform their duties.	qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 10% up to (and including) 15% of those persons did not hold appropriate qualifications and training to perform their duties.	qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 15% of those persons did not hold appropriate qualifications and training to perform their duties.
R1.4	N/A	N/A	N/A	The responsible entity's TVMP does not include mitigation measures to achieve sufficient clearances where restrictions to the ROW are in effect.
R1.5	N/A	N/A	N/A	The responsible entity did not establish or did not document a process for the immediate communication of vegetation conditions that present an imminent threat of line outage, as directed by the requirement.
R2	The responsible entity did not meet one of the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of	The responsible entity did not meet two of the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of	The responsible entity did not meet the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of	The responsible entity does not have an annual plan for vegetation management.  OR  The responsible entity has not implemented the annual plan for

	adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	vegetation management.
R3	<p>The responsible entity failed to provide a quarterly outage report, but did not experience any reportable outages.</p> <p>OR</p> <p>The responsible entity provided a quarterly report, but failed to report in the manner specified by one or more of the following subcomponents of Requirement R3: R3.1 or R3.2.</p>	<p>The responsible entity provided a quarterly report, but failed to include information required by R3.3.</p>	<p>The responsible entity provided a quarterly outage report, but failed to include a reportable Category 3 outage as described in R3.4.3.</p>	<p>The responsible entity experienced reportable outages but failed to provide a quarterly report.</p> <p>OR</p> <p>The responsible entity provided a quarterly outage report, but failed to include a reportable Category 1 (as described in R3.4.1) or Category 2 outage (as described in R3.4.2).</p>
R4	N/A	N/A	N/A	N/A

**E. Regional Differences**

None Identified.

**Version History**

Version	Date	Action	Change Tracking
1	TBA	<ol style="list-style-type: none"> <li>1. Added “Standard Development Roadmap.”</li> <li>2. Changed “60” to “Sixty” in section A, 5.2.</li> <li>3. Added “Proposed Effective Date: April 7, 2006” to footer.</li> <li>4. Added “Draft 3: November 17, 2005” to</li> </ol>	01/20/06

**Standard FAC-003-X — Transmission Vegetation Management Program**

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		footer.	
X	May 16, 2011	Made standard applicable to certain qualifying Generator Owners and brought overall standard format up to date	Revision under Project 2010-07

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary. When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.*

### **Right-of-Way (ROW)**

A corridor of land on which electric lines may be located. The applicable Transmission Owner or applicable Generator Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

The current glossary definition of this NERC term was modified to include applicable Generator Owners.

In November 2011, NERC’s Board of Trustees adopted FAC-003-2 – Transmission Vegetation Management (developed under Project 2007-07 Vegetation Management). Based on this approval, NERC staff will file FAC-003-2 with the applicable regulatory authorities. The Project 2010-07 SDT will move forward with ballots for both FAC-003-3 (proposed changes to the BOT-adopted FAC-003-2) and FAC-003-X (proposed changes to the FERC-approved FAC-003-1) with the intention of eventually only filing FAC-003-3. The SDT has elected to carry FAC-003-X through to ballot because if FAC-003-2 and FAC-003-3 are not approved by FERC, the SDT wants to be ready to file FAC-003-X to ensure that there is a functional entity responsible for managing vegetation on the piece of line commonly known as the generator interconnection Facility.

**A. Introduction**

**1. Title:** Transmission Vegetation Management Program

**2. Number:** FAC-003-X

**3. Purpose:** To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation-related outages of the transmission systems to the respective Regional Entity (~~RE~~) and the North American Electric Reliability Council (NERC).

Within the text of NERC Reliability Standard FAC-003-X, “transmission line(s)” and “applicable line(s)” can also refer to the generation Facilities as referenced in 4.4 and its subsections.

**4. Applicability:**

**4.1.** Regional Entity.

**4.2.** Applicable Transmission Owner

**4.2.1.** Transmission Owner that owns overhead transmission lines operated at 200 kV and above and to any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.

**4.3.** Applicable Generator Owner

**4.3.1.** Generator Owner that owns an overhead transmission line(s) that extends greater than one mile ~~or~~ (1.609 kilometers) beyond the fenced area of the generating station switchyard up to the point of interconnection with a Transmission Owner’s Facility or does not have a clear line of sight from the switchyard fence to the point of interconnection and is operated at 200 kV and above, and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.

With the line of sight reference in 4.3.1, the SDT simply seeks to clarify the exception language based on the intent that has been agreed upon by the stakeholder body. In its Consideration of Comments report from the last formal comment period, which ended on July 17, 2011, the SDT explained “We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor.” With the addition of an explicit line of sight reference here, the SDT believes it has clarified its original intent.

**5. Effective Dates:**

There are three effective dates associated with this implementation plan:

The first effective date applies to Transmission Owners.

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner become effective upon Board of Trustees' adoption.

The second effective date allows Generator Owners time to prepare a formal transmission vegetation management program as outlined in Requirement R1.

In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement ~~R3-R1~~ becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The third effective date allows entities time to comply with Requirements R2, R3, and R4.

In those jurisdictions where regulatory approval is required, Requirements R2, R3, and R4 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R2, R3, and R4 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

## **B. Requirements**

**R1.** Each applicable Transmission Owner or applicable Generator Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the applicable Transmission Owner's or applicable Generator Owner's objectives, practices, approved procedures, and work specifications<sup>1</sup>.

**R1.1.** The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the applicable Transmission Owner's or applicable Generator Owner's transmission lines.

**R1.2.** Each applicable Transmission Owner or applicable Generator Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the applicable Transmission Owner or applicable Generator Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.

**R1.2.1.** Clearance 1 — The applicable Transmission Owner or applicable Generator Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the applicable

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<sup>1</sup> ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.

Transmission Owner or applicable Generator Owner plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.

**R1.2.2.** Clearance 2 — The applicable Transmission Owner or applicable Generator Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These applicable Transmission Owner-specific or applicable Generator Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.

**R1.2.2.1** Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.

**R1.2.2.2** Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.

**R1.3.** All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner or Generator Owner, to perform their duties.

**R1.4.** Each applicable Transmission Owner or applicable Generator Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner or applicable Generator Owner is restricted from attaining the clearances specified in Requirement 1.2.1.

**R1.5.** Each Transmission Owner or applicable Generator Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.

[VRF – High]

**R2.** Each applicable Transmission Owner or applicable Generator Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or



regulatory authorities. Each applicable Transmission Owner or applicable Generator Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.

*[VRF – High]*

- R3.** Each applicable Transmission Owner or applicable Generator Owner shall report quarterly to its Regional Entity, or the Regional Entity’s designee, sustained transmission line outages determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation.
- R3.1.** Multiple sustained 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.
- R3.2.** The applicable Transmission Owner or applicable Generator Owner is not required to report to the Regional Entity, or the Regional Entity’s designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).
- R3.3.** The outage information provided by the applicable Transmission Owner or applicable Generator Owner to the Regional Entity, or the Regional Entity’s designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.
- R3.4.** An outage shall be categorized as one of the following:
- R3.4.1.** Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;
  - R3.4.2.** Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;
  - R3.4.3.** Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.

*[VRF – Lower]*

- R4.** The Regional Entity shall report the outage information provided to it by applicable Transmission Owners or applicable Generator Owners, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported outages.

*[VRF – Lower]*

## C. Measures

- M1.** Each applicable Transmission Owner or applicable Generator Owner has a documented TVMP, as identified in Requirement 1.
  - M1.1.** Each applicable Transmission Owner or applicable Generator Owner has documentation that the applicable Transmission Owner or applicable Generator Owner performed the vegetation inspections as identified in Requirement 1.1.
  - M1.2.** Each applicable Transmission Owner or applicable Generator Owner has documentation that describes the clearances identified in Requirement 1.2.
  - M1.3.** Each applicable Transmission Owner or applicable Generator Owner has documentation that the personnel directly involved in the design and implementation of the applicable Transmission Owner’s or applicable Generator Owner TVMP hold the qualifications identified by the Transmission Owner or applicable Generator Owner as required in Requirement 1.3.
  - M1.4.** Each applicable Transmission Owner or applicable Generator Owner has documentation that it has identified any areas not meeting the applicable Transmission Owner’s or applicable Generator Owner’s standard for vegetation management and any mitigating measures the Transmission Owner or applicable Generator Owner has taken to address these deficiencies as identified in Requirement 1.4.
  - M1.5.** Each applicable Transmission Owner or applicable Generator Owner has a documented process for the immediate communication of imminent threats by vegetation as identified in Requirement 1.5.
- M2.** Each applicable Transmission Owner or applicable Generator Owner has documentation that the Transmission Owner implemented the work plan identified in Requirement 2.
- M3.** Each applicable Transmission Owner or applicable Generator Owner has documentation that it has supplied quarterly outage reports to the Regional Entity, or the Regional Entity’s designee, as identified in Requirement 3.
- M4.** The Regional Entity has documentation that it provided quarterly outage reports to NERC as identified in Requirement 4.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

Compliance Monitor:

- Regional Entity for the Transmission Owner and Generator Owner
- Electric Reliability Organization or another Regional Entity approved by the ERO and FERC or other applicable government authorities

**1.2. Compliance Monitoring and Enforcement Processes:**

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.3. Data Retention**

The applicable Transmission Owner and applicable Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The applicable Transmission Owner and applicable Generator Owner shall retain evidence of Requirement 1, Measure 1, Requirement 2, Measure 2, and Requirement 3, Measure 3 from its last audit.

**1.4. Additional Compliance Information**

None.

**2. Violation Severity Levels**

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity did not include and keep current one of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current two of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current three of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current all required elements of the TVMP, as directed by the requirement.
R1.1	N/A	N/A	The applicable entity TVMP did not define a schedule, as directed by the requirement, or the type of ROW vegetation inspections, as directed by the requirement.	The applicable entity TVMP did not define a schedule, as directed by the requirement, nor the type of ROW vegetation inspections, as directed by the requirement.
R1.2	N/A	N/A	N/A	The responsible entity, in its TVMP, failed to identify and document clearances between vegetation and any overhead, ungrounded supply conductors.  OR  The responsible entity, in its

				<p>TVMP, failed to take into consideration transmission line voltage, or the effects of ambient temperature on conductor sag under maximum design loading, or the effects of wind velocities on conductor sway.</p> <p>OR</p> <p>The responsible entity, in its TVMP, failed to establish Clearance 1 or Clearance 2 values.</p>
R1.2.1	N/A	N/A	N/A	<p>The responsible entity failed to determine and document an appropriate clearance distance to be achieved at the time of transmission vegetation management work taking into account local conditions and the expected time frame in which the responsible entity expects to return for future vegetation management work.</p> <p>OR</p> <p>The responsible entity documented a Clearance 1 value that was smaller than its</p>

				Clearance 2 value.
R1.2.2	N/A	N/A	N/A	The responsible entity failed to determine and document Clearance 2 values taking into account local conditions and the expected time frame in which the responsible entity expects to return for future vegetation management work.
R1.2.2.1	N/A	N/A	N/A	Where transmission system transient overvoltage factors were known, clearances were not derived from Table 5, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.
R1.2.2.2	N/A	N/A	N/A	Where transmission system transient overvoltage factors are known, clearances were not derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.
R1.3	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, one of those persons did not hold appropriate	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, two of those persons did not hold appropriate	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, three of those persons did not hold appropriate	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, more than three of those persons did not hold appropriate

	qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, 5% or less of those persons did not hold appropriate qualifications and training to perform their duties.	qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 5% up to (and including) 10% of those persons did not hold appropriate qualifications and training to perform their duties.	qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 10% up to (and including) 15% of those persons did not hold appropriate qualifications and training to perform their duties.	qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 15% of those persons did not hold appropriate qualifications and training to perform their duties.
R1.4	N/A	N/A	N/A	The responsible entity's TVMP does not include mitigation measures to achieve sufficient clearances where restrictions to the ROW are in effect.
R1.5	N/A	N/A	N/A	The responsible entity did not establish or did not document a process for the immediate communication of vegetation conditions that present an imminent threat of line outage, as directed by the requirement.
R2	The responsible entity did not meet one of the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of	The responsible entity did not meet two of the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of	The responsible entity did not meet the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of	The responsible entity does not have an annual plan for vegetation management.  OR  The responsible entity has not implemented the annual plan for

	adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	vegetation management.
R3	<p>The responsible entity failed to provide a quarterly outage report, but did not experience any reportable outages.</p> <p>OR</p> <p>The responsible entity provided a quarterly report, but failed to report in the manner specified by one or more of the following subcomponents of Requirement R3: R3.1 or R3.2.</p>	<p>The responsible entity provided a quarterly report, but failed to include information required by R3.3.</p>	<p>The responsible entity provided a quarterly outage report, but failed to include a reportable Category 3 outage as described in R3.4.3.</p>	<p>The responsible entity experienced reportable outages but failed to provide a quarterly report.</p> <p>OR</p> <p>The responsible entity provided a quarterly outage report, but failed to include a reportable Category 1 (as described in R3.4.1) or Category 2 outage (as described in R3.4.2).</p>
R4	N/A	N/A	N/A	N/A

**E. Regional Differences**

None Identified.

**Version History**

Version	Date	Action	Change Tracking
1	TBA	<ol style="list-style-type: none"> <li>1. Added “Standard Development Roadmap.”</li> <li>2. Changed “60” to “Sixty” in section A, 5.2.</li> <li>3. Added “Proposed Effective Date: April 7, 2006” to footer.</li> <li>4. Added “Draft 3: November 17, 2005” to</li> </ol>	01/20/06

**Standard FAC-003-X — Transmission Vegetation Management Program**

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		footer.	
X	May 16, 2011	Made standard applicable to certain qualifying Generator Owners and brought overall standard format up to date	Revision under Project 2010-07



## Effective Dates

There are two effective dates associated with this standard.

The first effective date allows Generator Owners time to develop documented maintenance strategies or procedures or processes or specifications as outlined in Requirement R3.

In those jurisdictions where regulatory approval is required, Requirement R3 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The second effective date allows entities time to comply with Requirements R1, R2, R4, R5, R6, and R7.

In those jurisdictions where regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.
2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.
3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.

4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.
5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

Version History

<b>Version</b>	<b>Date</b>	<b>Action</b>	<b>Change Tracking</b>
3	September 29, 2011	Using the latest draft of FAC-003-2 from the Project 2007-07 SDT, modified proposed definitions and Applicability to include Generator Owners of a certain length.	Revision under Project 2010-07

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

### **Right-of-Way (ROW)**

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria.

The current glossary definition of this NERC term is modified to address the issues set forth in Paragraph 734 of FERC Order 693.

### **Vegetation Inspection**

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the applicable Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.

Current definition of Vegetation Inspection:  
The systematic examination of a transmission corridor to document vegetation conditions.

### **Minimum Vegetation Clearance Distance (MVCD)**

The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

*When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.*

In November 2011, NERC’s Board of Trustees adopted FAC-003-2 – Transmission Vegetation Management (developed under Project 2007-07 Vegetation Management). Based on this approval, NERC staff will file FAC-003-2 with the applicable regulatory authorities. The Project 2010-07 SDT will move forward with ballots for both FAC-003-3 (proposed changes to the BOT-adopted FAC-003-2) and FAC-003-X (proposed changes to the FERC-approved FAC-003-1) with the intention of eventually only filing FAC-003-3. The SDT has elected to carry FAC-003-X through to ballot because if FAC-003-2 and FAC-003-3 are not approved by FERC, the SDT wants to be ready to file FAC-003-X to ensure that there is a functional entity responsible for managing vegetation on the piece of line commonly known as the generator interconnection Facility.

## A. Introduction

- 1. Title:** Transmission Vegetation Management
- 2. Number:** FAC-003-3
- 3. Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

### 4. Applicability

#### 4.1. Functional Entities:

##### 4.1.1. Applicable Transmission Owners

- 4.1.1.1.** Transmission Owners that own Transmission Facilities defined in 4.2.

##### 4.1.2. Applicable Generator Owners

- 4.1.2.1.** Generator Owners that own generation Facilities defined in 4.3

- 4.2. Transmission Facilities:** Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal<sup>1</sup>, state, provincial, public, private, or tribal entities:

**Rationale:** The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

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<sup>1</sup> EPAAct 2005 section 1211c: “Access approvals by Federal agencies.”

- 4.2.1. Each overhead transmission line operated at 200kV or higher.
  - 4.2.2. Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.
  - 4.2.3. Each overhead transmission line operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.
  - 4.2.4. Each overhead transmission line identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.
- 4.3. **Generation Facilities:** Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal<sup>2</sup>, state, provincial, public, private, or tribal entities:
- 4.3.1. Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are:
    - 4.3.1.1. Operated at 200kV or higher; or
    - 4.3.1.2. Operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator; or
    - 4.3.1.3. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

Within the text of NERC Reliability Standard FAC-003-3, “transmission line(s) and “applicable line(s) can also refer to the generation Facilities as referenced in 4.3 and its subsections.

With the line of sight reference in 4.3.1, the SDT simply seeks to clarify the exception language based on the intent that has been agreed upon by the stakeholder body. In its [Consideration of Comments report](#) from the last formal comment period, which ended on July 17, 2011, the SDT explained “We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor.” With the addition of an explicit line of sight reference here, the SDT believes it has clarified its original intent.

Enforcement:

The Requirements within a Reliability Standard govern and will be enforced. The Requirements within a Reliability Standard define what an entity must do to be compliant and binds an entity to certain obligations of performance under

<sup>2</sup> EPAAct 2005 section 1211c: “Access approvals by Federal agencies.”

Section 215 of the Federal Power Act. Compliance will in all cases be measured by determining whether a party met or failed to meet the Reliability Standard Requirement given the specific facts and circumstances of its use, ownership or operation of the bulk power system.

Measures provide guidance on assessing non-compliance with the Requirements. Measures are the evidence that could be presented to demonstrate compliance with a Reliability Standard Requirement and are not intended to contain the quantitative metrics for determining satisfactory performance nor to limit how an entity may demonstrate compliance if valid alternatives to demonstrating compliance are available in a specific case. A Reliability Standard may be enforced in the absence of specified Measures.

Entities must comply with the “Compliance” section in its entirety, including the Administrative Procedure that sets forth, among other things, reporting requirements.

The “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” are provided for informational purposes. They are designed to convey guidance from NERC’s various activities. The “Guideline and Technical Basis” section and text boxes with “Examples” and “Rationale” are not intended to establish new Requirements under NERC’s Reliability Standards or to modify the Requirements in any existing NERC Reliability Standard. Implementation of the “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” is not a substitute for compliance with Requirements in NERC’s Reliability Standards.”

## **5. Background:**

- 5.1.1.** This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:
- 5.1.2.** a) Performance-based — defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome?*
- 5.1.3.** b) Risk-based — preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?*
- 5.1.4.** c) Competency-based — defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an*

*action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?*

- 5.1.5.** The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constraints such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

**5.1.6.** For this standard, the requirements have been developed as follows:

**5.1.7.** Performance-based: Requirements 1 and 2

**5.1.8.** Competency-based: Requirement 3

**5.1.9.** Risk-based: Requirements 4, 5, 6 and 7

**5.1.10.** R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

**5.1.11.** Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many



types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term “public lands” includes municipal lands, village lands, city lands, and a host of other governmental entities.

- 5.1.12.** This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.
- 5.1.13.** This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.
- 5.1.14.** Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

## B. Requirements and Measures

**R1.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below<sup>3</sup> [*Violation Risk Factor: High*] [*Time Horizon: Real-time*]:

1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage<sup>4</sup>,
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage<sup>5</sup>,
3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage<sup>4</sup>,
4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage<sup>4</sup>.

**M1.** Each applicable Transmission Owner

### Rationale for R1 and R2:

Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable Transmission Owner's or applicable Generator Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.
2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

<sup>3</sup> This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.

<sup>4</sup> If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

<sup>5</sup> Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

**R2.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below<sup>2</sup> [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time*]:

1. An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage<sup>3</sup>,
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage<sup>4</sup>,
3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage<sup>4</sup>,
4. An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage<sup>4</sup>

**M2.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)

**R3.** Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following:

**3.1** Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;

**3.2** Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

*[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]:*

**Rationale**

The documentation provides a basis for evaluating the competency of the applicable Transmission Owner’s or applicable Generator Owner’s vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions. See Figure

**M3.** The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

**R4.** Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment *[Violation Risk Factor: Medium] [Time Horizon: Real-time]*.

**Rationale**

This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

**M4.** Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

**R5.** When a applicable Transmission Owner and applicable Generator Owner is constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

**Rationale**

Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

**M5.** Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

**Rationale**

Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

**R6.** Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW<sup>6</sup> [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

<sup>6</sup> When the applicable Transmission Owner or applicable Generator Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.

**M6.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

**R7.** Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan

**Rationale**

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

(measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

- Change in expected growth rate/ environmental factors
- Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner<sup>7</sup>
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Emerging technologies

**M7.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of

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<sup>7</sup> Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.

acceptable forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records.  
(R7)

## **C. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1 Compliance Enforcement Authority**

#### **1.2 Regional Entity Evidence Retention**

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, Measures M1, M2, M3, M5, M6 and M7 for three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### **1.3 Compliance Monitoring and Enforcement Processes:**

**5.1.15.** Compliance Audit

**5.1.16.** Self-Certification

**5.1.17.** Spot Checking

**5.1.18.** Compliance Violation Investigation

**5.1.19.** Self-Reporting

Complaint

Periodic Data Submittal

#### **1.4 Additional Compliance Information**



***Periodic Data Submittal:*** The applicable Transmission Owner and applicable Generator Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

**Table of Compliance Elements**

R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Real-time	High			<p>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.</p>	<p>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following:</p> <ul style="list-style-type: none"> <li>• A fall-in from inside the active transmission line ROW</li> <li>• Blowing together of applicable lines and vegetation located inside the active transmission line ROW</li> <li>• A grow-in</li> </ul>
R2	Real-time	Medium			<p>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.</p>	<p>The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following:</p> <ul style="list-style-type: none"> <li>• A fall-in from inside the active transmission line</li> </ul>

						<p>ROW</p> <ul style="list-style-type: none"> <li>Blowing together of applicable lines and vegetation located inside the active transmission line ROW</li> <li>A grow-in</li> </ul>
R3	Long-Term Planning	Lower		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity's applicable lines. (Requirement R3, Part 3.2)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines. Requirement R3, Part 3.1)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity's applicable lines.
R4	Real-time	Medium			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5	Operations Planning	Medium				The responsible entity did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6	Operations	Medium	The responsible entity	The responsible entity failed	The responsible entity failed to	The responsible entity failed to

	Planning		failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7	Operations Planning	Medium	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Differences

None.

E. Interpretations

None.

F. Associated Documents

Guideline and Technical Basis (attached).

## Guideline and Technical Basis

### Effective dates:

The first two sentences of the Effective Dates section is standard language used in most NERC standards to cover the general effective date and is sufficient to cover the vast majority of situations. Five special cases are needed to cover effective dates for individual lines which undergo transitions after the general effective date. These special cases cover the effective dates for those lines which are initially becoming subject to the standard, those lines which are changing their applicability within the standard, and those lines which are changing in a manner that removes their applicability to the standard.

Case 1 is needed because the Planning Coordinators may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2011 may identify a line to have that designation beginning in PY 2021, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. The table below has some explanatory examples of the application.

<u>Date that Planning Study is completed</u>	<u>PY the line will become an IROL element</u>	<u>Date 1</u>	<u>Date 2</u>	<u>Effective Date The latter of Date 1 or Date 2</u>
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Case 2 is needed because a line operating below 200kV designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Case 3 is needed because a line operating at 200 kV or above that once was designated as an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network. Such changes result in the need to apply R1 to that line until that date is reached and then to apply R2 to that line thereafter.

Case 4 is needed because an existing line that is to be operated at 200 kV or above can be acquired by an applicable Transmission Owner or applicable Generator Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network which will thereafter make the line subject to the standard.

Case 5 is needed because an existing line that is operated below 200 kV can be acquired by an applicable Transmission Owner or applicable Generator Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network. In this special case the line upon acquisition was designated as an element of an Interconnection Reliability Operating Limit (IROL) or an element of a Major WECC Transfer Path.

### **Defined Terms:**

#### **Explanation for revising the definition of ROW:**

The current NERC glossary definition of Right of Way has been modified to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This modified definition represents a slight but significant departure from the strict legal definition of “right of way” in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the revised definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

**Explanation for revising the definition of Vegetation Inspections:**

The current glossary definition of this NERC term is being modified to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

**Explanation of the definition of the MVCD:**

The MVCD is a calculated minimum distance that is derived from the Gallet Equations. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 below provides MVCD values for various voltages and altitudes. Details of the equations and an example calculation are provided in Appendix 1 of the Technical Reference Document.

**Requirements R1 and R2:**

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each applicable Transmission Owner or applicable Generator Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element of an IROL or Major WECC Transfer Path. R2 is applicable to all other lines that are not elements of IROLs, and not elements of Major WECC Transfer Paths.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations as described more fully in the Technical Reference document.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will prevent transmission outages.

If the applicable Transmission Owner or applicable Generator Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.



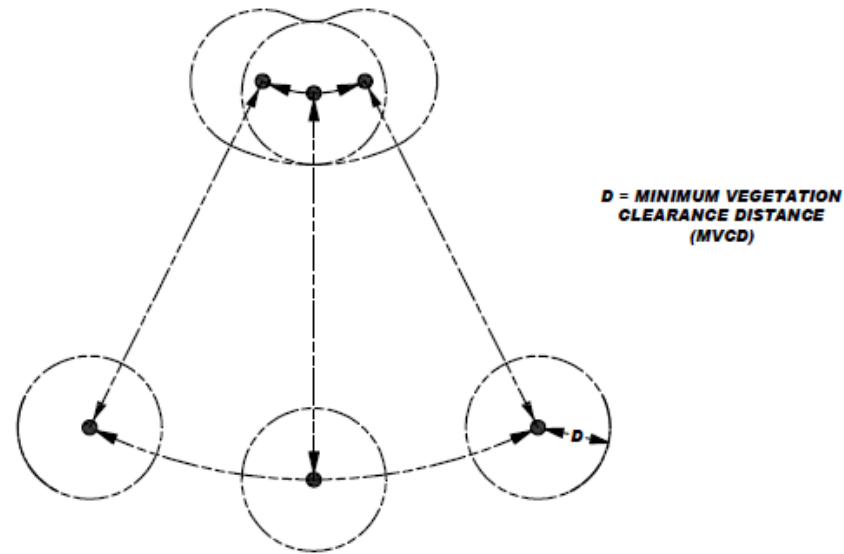
**Requirement R3:** R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable Transmission Owner or applicable Generator Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an applicable Transmission Owner or applicable Generator Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below. In the Technical Reference document more figures and explanations of conductor dynamics are provided.



**Figure 1**

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

**Requirement R4:**

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner or applicable Generator Owner employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

**Requirement R5:**

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the applicable Transmission Owner or applicable Generator Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The applicable Transmission Owner or applicable Generator Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

**Requirement R6:**

R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner’s ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission Owner or applicable Generator Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be  $100/2000 = 0.05$  or 5%. The “Low VSL” for R6 would apply in this example.

**Requirement R7:**

R7 is a risk-based requirement. The applicable Transmission Owner or applicable Generator Owner is required to complete its annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a “span-by-span”, or even a “line-by-line” detailed description of all work to be performed. It is only intended to require that the applicable Transmission Owner or applicable Generator Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

For example, when an applicable Transmission Owner or applicable Generator Owner identifies 1,000 miles of applicable transmission lines to be completed in the applicable Transmission Owner’s or applicable Generator Owner’s annual plan, the applicable Transmission Owner or applicable Generator Owner will be responsible completing those identified miles. If a applicable Transmission Owner or applicable Generator Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be:  $1000 - 100$  (deferred miles) = 900 modified annual plan, or  $900 / 900 = 100\%$  completed annual miles. If an applicable Transmission Owner or applicable Generator Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be:  $1000 - 875 = 125$  miles failed to complete then,  $125$  miles (not completed) /  $1000$  total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner’s or applicable Generator Owner’s system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.

In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner’s or applicable Generator Owner’s easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.



FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)<sup>8</sup>  
 For **Alternating Current** Voltages (feet)

( AC ) Nominal System Voltage (KV)	( AC ) Maximum System Voltage (kV) <sup>9</sup>	MVCD (feet)  Over sea level up to 500 ft	MVCD (feet)  Over 500 ft up to 1000 ft	MVCD feet  Over 1000 ft up to 2000 ft	MVCD feet  Over 2000 ft up to 3000 ft	MVCD feet  Over 3000 ft up to 4000 ft	MVCD feet  Over 4000 ft up to 5000 ft	MVCD feet  Over 5000 ft up to 6000 ft	MVCD feet  Over 6000 ft up to 7000 ft	MVCD feet  Over 7000 ft up to 8000 ft	MVCD feet  Over 8000 ft up to 9000 ft	MVCD feet  Over 9000 ft up to 10000 ft	MVCD feet  Over 10000 ft up to 11000 ft
765	800	8.2ft	8.33ft	8.61ft	8.89ft	9.17ft	9.45ft	9.73ft	10.01ft	10.29ft	10.57ft	10.85ft	11.13ft
500	550	5.15ft	5.25ft	5.45ft	5.66ft	5.86ft	6.07ft	6.28ft	6.49ft	6.7ft	6.92ft	7.13ft	7.35ft
345	362	3.19ft	3.26ft	3.39ft	3.53ft	3.67ft	3.82ft	3.97ft	4.12ft	4.27ft	4.43ft	4.58ft	4.74ft
287	302	3.88ft	3.96ft	4.12ft	4.29ft	4.45ft	4.62ft	4.79ft	4.97ft	5.14ft	5.32ft	5.50ft	5.68ft
230	242	3.03ft	3.09ft	3.22ft	3.36ft	3.49ft	3.63ft	3.78ft	3.92ft	4.07ft	4.22ft	4.37ft	4.53ft
161*	169	2.05ft	2.09ft	2.19ft	2.28ft	2.38ft	2.48ft	2.58ft	2.69ft	2.8ft	2.91ft	3.03ft	3.14ft
138*	145	1.74ft	1.78ft	1.86ft	1.94ft	2.03ft	2.12ft	2.21ft	2.3ft	2.4ft	2.49ft	2.59ft	2.7ft
115*	121	1.44ft	1.47ft	1.54ft	1.61ft	1.68ft	1.75ft	1.83ft	1.91ft	1.99ft	2.07ft	2.16ft	2.25ft
88*	100	1.18ft	1.21ft	1.26ft	1.32ft	1.38ft	1.44ft	1.5ft	1.57ft	1.64ft	1.71ft	1.78ft	1.86ft
69*	72	0.84ft	0.86ft	0.90ft	0.94ft	0.99ft	1.03ft	1.08ft	1.13ft	1.18ft	1.23ft	1.28ft	1.34ft

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

<sup>8</sup> The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

<sup>9</sup> Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.



**TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)<sup>7</sup>  
For Alternating Current Voltages (meters)**

( AC ) Nominal System Voltage (KV)	( AC ) Maximum System Voltage <sup>8</sup> (kV)	MVCD meters  Over sea level up to 152.4 m	MVCD meters  Over 152.4 m up to 304.8 m	MVCD meters  Over 304.8 m up to 609.6m	MVCD meters  Over 609.6m up to 914.4m	MVCD meters  Over 914.4m up to 1219.2m	MVCD meters  Over 1219.2m up to 1524m	MVCD meters  Over 1524 m up to 1828.8 m	MVCD meters  Over 1828.8m up to 2133.6m	MVCD meters  Over 2133.6m up to 2438.4m	MVCD meters  Over 2438.4m up to 2743.2m	MVCD meters  Over 2743.2m up to 3048m	MVCD meters  Over 3048m up to 3352.8m
765	800	2.49m	2.54m	2.62m	2.71m	2.80m	2.88m	2.97m	3.05m	3.14m	3.22m	3.31m	3.39m
500	550	1.57m	1.6m	1.66m	1.73m	1.79m	1.85m	1.91m	1.98m	2.04m	2.11m	2.17m	2.24m
345	362	0.97m	0.99m	1.03m	1.08m	1.12m	1.16m	1.21m	1.26m	1.30m	1.35m	1.40m	1.44m
287	302	1.18m	0.88m	1.26m	1.31m	1.36m	1.41m	1.46m	1.51m	1.57m	1.62m	1.68m	1.73m
230	242	0.92m	0.94m	0.98m	1.02m	1.06m	1.11m	1.15m	1.19m	1.24m	1.29m	1.33m	1.38m
161*	169	0.62m	0.64m	0.67m	0.69m	0.73m	0.76m	0.79m	0.82m	0.85m	0.89m	0.92m	0.96m
138*	145	0.53m	0.54m	0.57m	0.59m	0.62m	0.65m	0.67m	0.70m	0.73m	0.76m	0.79m	0.82m
115*	121	0.44m	0.45m	0.47m	0.49m	0.51m	0.53m	0.56m	0.58m	0.61m	0.63m	0.66m	0.69m
88*	100	0.36m	0.37m	0.38m	0.40m	0.42m	0.44m	0.46m	0.48m	0.50m	0.52m	0.54m	0.57m
69*	72	0.26m	0.26m	0.27m	0.29m	0.30m	0.31m	0.33m	0.34m	0.36m	0.37m	0.39m	0.41m

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)<sup>7</sup>  
 For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)
	Over sea level up to 500 ft	Over 500 ft up to 1000 ft	Over 1000 ft up to 2000 ft	Over 2000 ft up to 3000 ft	Over 3000 ft up to 4000 ft	Over 4000 ft up to 5000 ft	Over 5000 ft up to 6000 ft	Over 6000 ft up to 7000 ft	Over 7000 ft up to 8000 ft	Over 8000 ft up to 9000 ft	Over 9000 ft up to 10000 ft	Over 10000 ft up to 11000 ft
	(Over sea level up to 152.4 m)	(Over 152.4 m up to 304.8 m)	(Over 304.8 m up to 609.6m)	(Over 609.6m up to 914.4m)	(Over 914.4m up to 1219.2m)	(Over 1219.2m up to 1524m)	(Over 1524 m up to 1828.8 m)	(Over 1828.8m up to 2133.6m)	(Over 2133.6m up to 2438.4m)	(Over 2438.4m up to 2743.2m)	(Over 2743.2m up to 3048m)	(Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

**Notes:**

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet Equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 uses the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-01 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines, as such, are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line is approximately 2.0 per unit. This value is a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the

maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below is considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit is considered a realistic maximum.

The Gallet Equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet Equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

While EPRI is currently trying to establish empirical data for spark-over distances to live vegetation, there are no spark-over formulas currently derived expressly for vegetation to conductor minimum distances. Therefore the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice. The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

**Comparison of spark-over distances computed using Gallet wet equations vs.  
IEEE 516-2003 MAID distances**

<b>( AC ) Nom System Voltage (kV)</b>	<b>( AC ) Max System Voltage (kV)</b>	<b>Transient Over-voltage Factor (T)</b>	<b>Clearance (ft.) Gallet (wet) @ Alt. 3000 feet</b>	<b>Table 7 (Table D.5 for feet) IEEE 516-2003 MAID (ft) @ Alt. 3000 feet</b>
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

## Effective Dates

There are two effective dates associated with this standard.

The first effective date allows Generator Owners time to develop documented maintenance strategies or procedures or processes or specifications as outlined in Requirement R3.

In those jurisdictions where regulatory approval is required, Requirement R3 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The second effective date allows entities time to comply with Requirements R1, R2, R4, R5, R6, and R7.

In those jurisdictions where regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.
2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.
3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.

4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.
5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

Version History

<b>Version</b>	<b>Date</b>	<b>Action</b>	<b>Change Tracking</b>
3	September 29, 2011	Using the latest draft of FAC-003-2 from the Project 2007-07 SDT, modified proposed definitions and Applicability to include Generator Owners of a certain length.	Revision under Project 2010-07



## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

### **Right-of-Way (ROW)**

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria.

The current glossary definition of this NERC term is modified to address the issues set forth in Paragraph 734 of FERC Order 693.

### **Vegetation Inspection**

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the applicable Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.

Current definition of Vegetation Inspection:  
The systematic examination of a transmission corridor to document vegetation conditions.

### **Minimum Vegetation Clearance Distance (MVCD)**

The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

*When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.*

In November 2011, NERC’s Board of Trustees adopted FAC-003-2 – Transmission Vegetation Management (developed under Project 2007-07 Vegetation Management). Based on this approval, NERC staff will file FAC-003-2 with the applicable regulatory authorities. The Project 2010-07 SDT will move forward with ballots for both FAC-003-3 (proposed changes to the BOT-adopted FAC-003-2) and FAC-003-X (proposed changes to the FERC-approved FAC-003-1) with the intention of eventually only filing FAC-003-3. The SDT has elected to carry FAC-003-X through to ballot because if FAC-003-2 and FAC-003-3 are not approved by FERC, the SDT wants to be ready to file FAC-003-X to ensure that there is a functional entity responsible for managing vegetation on the piece of line commonly known as the generator interconnection Facility.

## A. Introduction

- 1. Title:** Transmission Vegetation Management
- 2. Number:** FAC-003-3
- 3. Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

### 4. Applicability

#### 4.1. Functional Entities:

##### 4.1.1. Applicable Transmission Owners

- 4.1.1.1.** Transmission Owners that own Transmission Facilities defined in 4.2.

##### 4.1.2. Applicable Generator Owners

- 4.1.2.1.** Generator Owners that own generation Facilities defined in 4.3

- 4.2. Transmission Facilities:** Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal<sup>1</sup>, state, provincial, public, private, or tribal entities:

**Rationale:** The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

<sup>1</sup> EPAAct 2005 section 1211c: “Access approvals by Federal agencies.”

- 4.2.1. Each overhead transmission line operated at 200kV or higher.
  - 4.2.2. Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.
  - 4.2.3. Each overhead transmission line operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.
  - 4.2.4. Each overhead transmission line identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.
- 4.3. **Generation Facilities:** Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal<sup>2</sup>, state, provincial, public, private, or tribal entities:
- 4.3.1. Overhead transmission lines that extend greater than one mile ~~or~~ (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are:
    - 4.3.1.1. Operated at 200kV or higher; or
    - 4.3.1.2. Operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator; or;
    - 4.3.1.3. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

Within the text of NERC Reliability Standard FAC-003-3, “transmission line(s) and “applicable line(s) can also refer to the generation Facilities as referenced in 4.3 and its subsections.

With the line of sight reference in 4.3.1, the SDT simply seeks to clarify the exception language based on the intent that has been agreed upon by the stakeholder body. In its Consideration of Comments report from the last formal comment period, which ended on July 17, 2011, the SDT explained “We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor.” With the addition of an explicit line of sight reference here, the SDT believes it has clarified its original intent.

Enforcement:

The Requirements within a Reliability Standard govern and will be enforced. The Requirements within a Reliability Standard define what an entity must do to be compliant and binds an entity to certain obligations of performance under

<sup>2</sup> EPAAct 2005 section 1211c: “Access approvals by Federal agencies.”

Section 215 of the Federal Power Act. Compliance will in all cases be measured by determining whether a party met or failed to meet the Reliability Standard Requirement given the specific facts and circumstances of its use, ownership or operation of the bulk power system.

Measures provide guidance on assessing non-compliance with the Requirements. Measures are the evidence that could be presented to demonstrate compliance with a Reliability Standard Requirement and are not intended to contain the quantitative metrics for determining satisfactory performance nor to limit how an entity may demonstrate compliance if valid alternatives to demonstrating compliance are available in a specific case. A Reliability Standard may be enforced in the absence of specified Measures.

Entities must comply with the “Compliance” section in its entirety, including the Administrative Procedure that sets forth, among other things, reporting requirements.

The “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” are provided for informational purposes. They are designed to convey guidance from NERC’s various activities. The “Guideline and Technical Basis” section and text boxes with “Examples” and “Rationale” are not intended to establish new Requirements under NERC’s Reliability Standards or to modify the Requirements in any existing NERC Reliability Standard. Implementation of the “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” is not a substitute for compliance with Requirements in NERC’s Reliability Standards.”

## **5. Background:**

- 5.1.1.** This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:
- 5.1.2.** a) Performance-based — defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome?*
- 5.1.3.** b) Risk-based — preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?*
- 5.1.4.** c) Competency-based — defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an*

*action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?*

- 5.1.5.** The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

**5.1.6.** For this standard, the requirements have been developed as follows:

**5.1.7.** Performance-based: Requirements 1 and 2

**5.1.8.** Competency-based: Requirement 3

**5.1.9.** Risk-based: Requirements 4, 5, 6 and 7

**5.1.10.** R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

**5.1.11.** Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many

types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term “public lands” includes municipal lands, village lands, city lands, and a host of other governmental entities.

- 5.1.12.** This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.
- 5.1.13.** This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.
- 5.1.14.** Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.



## B. Requirements and Measures

**R1.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below<sup>3</sup> [*Violation Risk Factor: High*] [*Time Horizon: Real-time*]:

1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage<sup>4</sup>,
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage<sup>5</sup>,
3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage<sup>4</sup>,
4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage<sup>4</sup>.

**M1.** Each applicable Transmission Owner

### Rationale for R1 and R2:

Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable Transmission Owner's or applicable Generator Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.
2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

<sup>3</sup> This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.

<sup>4</sup> If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

<sup>5</sup> Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

- R2.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below<sup>2</sup> [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time*]:
1. An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage<sup>3</sup>,
  2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage<sup>4</sup>,
  3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage<sup>4</sup>,
  4. An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage<sup>4</sup>
- M2.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)



**R3.** Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following:

**3.1** Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;

**3.2** Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]:

**Rationale**

The documentation provides a basis for evaluating the competency of the applicable Transmission Owner’s or applicable Generator Owner’s vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions. See Figure

**M3.** The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

**R4.** Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment [Violation Risk Factor: Medium] [Time Horizon: Real-time].

**Rationale**

This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

**M4.** Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

**R5.** When a applicable Transmission Owner and applicable Generator Owner is constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

**Rationale**

Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

**M5.** Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

**Rationale**

Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

**R6.** Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW<sup>6</sup> [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

<sup>6</sup> When the applicable Transmission Owner or applicable Generator Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.

**M6.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

**R7.** Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan

**Rationale**

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

(measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

- Change in expected growth rate/ environmental factors
- Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner<sup>7</sup>
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Emerging technologies

**M7.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of

<sup>7</sup> Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.

acceptable forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records.  
(R7)

## C. Compliance

### 1. Compliance Monitoring Process

#### 1.1 Compliance Enforcement Authority

#### 1.2 Regional Entity Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, Measures M1, M2, M3, M5, M6 and M7 for three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.3 Compliance Monitoring and Enforcement Processes:

5.1.15. Compliance Audit

5.1.16. Self-Certification

5.1.17. Spot Checking

5.1.18. Compliance Violation Investigation

5.1.19. Self-Reporting

Complaint

Periodic Data Submittal

#### 1.4 Additional Compliance Information

***Periodic Data Submittal:*** The applicable Transmission Owner and applicable Generator Owner will submit a quarterly report to its Regional Entity, or the Regional Entity’s designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

**Table of Compliance Elements**

R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Real-time	High			<p>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.</p>	<p>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following:</p> <ul style="list-style-type: none"> <li>• A fall-in from inside the active transmission line ROW</li> <li>• Blowing together of applicable lines and vegetation located inside the active transmission line ROW</li> <li>• A grow-in</li> </ul>
R2	Real-time	Medium			<p>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.</p>	<p>The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following:</p> <ul style="list-style-type: none"> <li>• A fall-in from inside the active transmission line</li> </ul>

						<p>ROW</p> <ul style="list-style-type: none"> <li>Blowing together of applicable lines and vegetation located inside the active transmission line ROW</li> <li>A grow-in</li> </ul>
R3	Long-Term Planning	Lower		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity’s applicable lines. (Requirement R3, Part 3.2)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity’s applicable lines. Requirement R3, Part 3.1)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity’s applicable lines.
R4	Real-time	Medium			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5	Operations Planning	Medium				The responsible entity did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6	Operations	Medium	The responsible entity	The responsible entity failed	The responsible entity failed to	The responsible entity failed to



	Planning		failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7	Operations Planning	Medium	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Differences

None.

E. Interpretations

None.

F. Associated Documents

Guideline and Technical Basis (attached).

## Guideline and Technical Basis

### Effective dates:

The first two sentences of the Effective Dates section is standard language used in most NERC standards to cover the general effective date and is sufficient to cover the vast majority of situations. Five special cases are needed to cover effective dates for individual lines which undergo transitions after the general effective date. These special cases cover the effective dates for those lines which are initially becoming subject to the standard, those lines which are changing their applicability within the standard, and those lines which are changing in a manner that removes their applicability to the standard.

Case 1 is needed because the Planning Coordinators may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2011 may identify a line to have that designation beginning in PY 2021, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. The table below has some explanatory examples of the application.

<u>Date that Planning Study is completed</u>	<u>PY the line will become an IROL element</u>	<u>Date 1</u>	<u>Date 2</u>	<u>Effective Date The latter of Date 1 or Date 2</u>
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Case 2 is needed because a line operating below 200kV designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Case 3 is needed because a line operating at 200 kV or above that once was designated as an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network. Such changes result in the need to apply R1 to that line until that date is reached and then to apply R2 to that line thereafter.

Case 4 is needed because an existing line that is to be operated at 200 kV or above can be acquired by an applicable Transmission Owner or applicable Generator Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network which will thereafter make the line subject to the standard.

Case 5 is needed because an existing line that is operated below 200 kV can be acquired by an applicable Transmission Owner or applicable Generator Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network. In this special case the line upon acquisition was designated as an element of an Interconnection Reliability Operating Limit (IROL) or an element of a Major WECC Transfer Path.

### **Defined Terms:**

#### **Explanation for revising the definition of ROW:**

The current NERC glossary definition of Right of Way has been modified to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This modified definition represents a slight but significant departure from the strict legal definition of “right of way” in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the revised definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

### **Explanation for revising the definition of Vegetation Inspections:**

The current glossary definition of this NERC term is being modified to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

### **Explanation of the definition of the MVCD:**

The MVCD is a calculated minimum distance that is derived from the Gallet Equations. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 below provides MVCD values for various voltages and altitudes. Details of the equations and an example calculation are provided in Appendix 1 of the Technical Reference Document.

### **Requirements R1 and R2:**

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each applicable Transmission Owner or applicable Generator Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element of an IROL or Major WECC Transfer Path. R2 is applicable to all other lines that are not elements of IROLs, and not elements of Major WECC Transfer Paths.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations as described more fully in the Technical Reference document.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will prevent transmission outages.

If the applicable Transmission Owner or applicable Generator Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

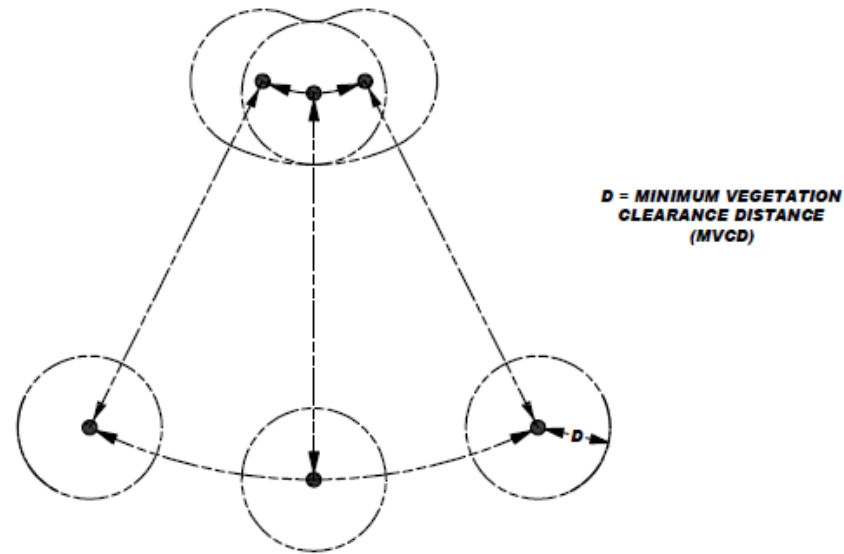
**Requirement R3:** R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable Transmission Owner or applicable Generator Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an applicable Transmission Owner or applicable Generator Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below. In the Technical Reference document more figures and explanations of conductor dynamics are provided.



**Figure 1**

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

**Requirement R4:**

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner or applicable Generator Owner employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

**Requirement R5:**

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:



- Identifying locations where the applicable Transmission Owner or applicable Generator Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The applicable Transmission Owner or applicable Generator Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

**Requirement R6:**

R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner’s ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission Owner or applicable Generator Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be  $100/2000 = 0.05$  or 5%. The “Low VSL” for R6 would apply in this example.

**Requirement R7:**

R7 is a risk-based requirement. The applicable Transmission Owner or applicable Generator Owner is required to complete its annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a “span-by-span”, or even a “line-by-line” detailed description of all work to be performed. It is only intended to require that the applicable Transmission Owner or applicable Generator Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

For example, when an applicable Transmission Owner or applicable Generator Owner identifies 1,000 miles of applicable transmission lines to be completed in the applicable Transmission Owner’s or applicable Generator Owner’s annual plan, the applicable Transmission Owner or applicable Generator Owner will be responsible completing those identified miles. If a applicable Transmission Owner or applicable Generator Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be:  $1000 - 100$  (deferred miles) = 900 modified annual plan, or  $900 / 900 = 100\%$  completed annual miles. If an applicable Transmission Owner or applicable Generator Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be:  $1000 - 875 = 125$  miles failed to complete then,  $125$  miles (not completed) /  $1000$  total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner’s or applicable Generator Owner’s system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.

In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner’s or applicable Generator Owner’s easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.



FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)<sup>8</sup>  
 For **Alternating Current** Voltages (feet)

( AC ) Nominal System Voltage (KV)	( AC ) Maximum System Voltage (kV) <sup>9</sup>	MVCD (feet)  Over sea level up to 500 ft	MVCD (feet)  Over 500 ft up to 1000 ft	MVCD feet  Over 1000 ft up to 2000 ft	MVCD feet  Over 2000 ft up to 3000 ft	MVCD feet  Over 3000 ft up to 4000 ft	MVCD feet  Over 4000 ft up to 5000 ft	MVCD feet  Over 5000 ft up to 6000 ft	MVCD feet  Over 6000 ft up to 7000 ft	MVCD feet  Over 7000 ft up to 8000 ft	MVCD feet  Over 8000 ft up to 9000 ft	MVCD feet  Over 9000 ft up to 10000 ft	MVCD feet  Over 10000 ft up to 11000 ft
765	800	8.2ft	8.33ft	8.61ft	8.89ft	9.17ft	9.45ft	9.73ft	10.01ft	10.29ft	10.57ft	10.85ft	11.13ft
500	550	5.15ft	5.25ft	5.45ft	5.66ft	5.86ft	6.07ft	6.28ft	6.49ft	6.7ft	6.92ft	7.13ft	7.35ft
345	362	3.19ft	3.26ft	3.39ft	3.53ft	3.67ft	3.82ft	3.97ft	4.12ft	4.27ft	4.43ft	4.58ft	4.74ft
287	302	3.88ft	3.96ft	4.12ft	4.29ft	4.45ft	4.62ft	4.79ft	4.97ft	5.14ft	5.32ft	5.50ft	5.68ft
230	242	3.03ft	3.09ft	3.22ft	3.36ft	3.49ft	3.63ft	3.78ft	3.92ft	4.07ft	4.22ft	4.37ft	4.53ft
161*	169	2.05ft	2.09ft	2.19ft	2.28ft	2.38ft	2.48ft	2.58ft	2.69ft	2.8ft	2.91ft	3.03ft	3.14ft
138*	145	1.74ft	1.78ft	1.86ft	1.94ft	2.03ft	2.12ft	2.21ft	2.3ft	2.4ft	2.49ft	2.59ft	2.7ft
115*	121	1.44ft	1.47ft	1.54ft	1.61ft	1.68ft	1.75ft	1.83ft	1.91ft	1.99ft	2.07ft	2.16ft	2.25ft
88*	100	1.18ft	1.21ft	1.26ft	1.32ft	1.38ft	1.44ft	1.5ft	1.57ft	1.64ft	1.71ft	1.78ft	1.86ft
69*	72	0.84ft	0.86ft	0.90ft	0.94ft	0.99ft	1.03ft	1.08ft	1.13ft	1.18ft	1.23ft	1.28ft	1.34ft

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

<sup>8</sup> The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

<sup>9</sup> Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

**TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)<sup>7</sup>  
For Alternating Current Voltages (meters)**

( AC ) Nominal System Voltage (KV)	( AC ) Maximum System Voltage <sup>8</sup> (kV)	MVCD meters  Over sea level up to 152.4 m	MVCD meters  Over 152.4 m up to 304.8 m	MVCD meters  Over 304.8 m up to 609.6m	MVCD meters  Over 609.6m up to 914.4m	MVCD meters  Over 914.4m up to 1219.2m	MVCD meters  Over 1219.2m up to 1524m	MVCD meters  Over 1524 m up to 1828.8 m	MVCD meters  Over 1828.8m up to 2133.6m	MVCD meters  Over 2133.6m up to 2438.4m	MVCD meters  Over 2438.4m up to 2743.2m	MVCD meters  Over 2743.2m up to 3048m	MVCD meters  Over 3048m up to 3352.8m
765	800	2.49m	2.54m	2.62m	2.71m	2.80m	2.88m	2.97m	3.05m	3.14m	3.22m	3.31m	3.39m
500	550	1.57m	1.6m	1.66m	1.73m	1.79m	1.85m	1.91m	1.98m	2.04m	2.11m	2.17m	2.24m
345	362	0.97m	0.99m	1.03m	1.08m	1.12m	1.16m	1.21m	1.26m	1.30m	1.35m	1.40m	1.44m
287	302	1.18m	0.88m	1.26m	1.31m	1.36m	1.41m	1.46m	1.51m	1.57m	1.62m	1.68m	1.73m
230	242	0.92m	0.94m	0.98m	1.02m	1.06m	1.11m	1.15m	1.19m	1.24m	1.29m	1.33m	1.38m
161*	169	0.62m	0.64m	0.67m	0.69m	0.73m	0.76m	0.79m	0.82m	0.85m	0.89m	0.92m	0.96m
138*	145	0.53m	0.54m	0.57m	0.59m	0.62m	0.65m	0.67m	0.70m	0.73m	0.76m	0.79m	0.82m
115*	121	0.44m	0.45m	0.47m	0.49m	0.51m	0.53m	0.56m	0.58m	0.61m	0.63m	0.66m	0.69m
88*	100	0.36m	0.37m	0.38m	0.40m	0.42m	0.44m	0.46m	0.48m	0.50m	0.52m	0.54m	0.57m
69*	72	0.26m	0.26m	0.27m	0.29m	0.30m	0.31m	0.33m	0.34m	0.36m	0.37m	0.39m	0.41m

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)<sup>7</sup>  
 For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)
	Over sea level up to 500 ft	Over 500 ft up to 1000 ft	Over 1000 ft up to 2000 ft	Over 2000 ft up to 3000 ft	Over 3000 ft up to 4000 ft	Over 4000 ft up to 5000 ft	Over 5000 ft up to 6000 ft	Over 6000 ft up to 7000 ft	Over 7000 ft up to 8000 ft	Over 8000 ft up to 9000 ft	Over 9000 ft up to 10000 ft	Over 10000 ft up to 11000 ft
	(Over sea level up to 152.4 m)	(Over 152.4 m up to 304.8 m)	(Over 304.8 m up to 609.6m)	(Over 609.6m up to 914.4m)	(Over 914.4m up to 1219.2m)	(Over 1219.2m up to 1524m)	(Over 1524 m up to 1828.8 m)	(Over 1828.8m up to 2133.6m)	(Over 2133.6m up to 2438.4m)	(Over 2438.4m up to 2743.2m)	(Over 2743.2m up to 3048m)	(Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

**Notes:**

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet Equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 uses the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-01 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines, as such, are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line is approximately 2.0 per unit. This value is a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the



maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below is considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit is considered a realistic maximum.

The Gallet Equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet Equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

While EPRI is currently trying to establish empirical data for spark-over distances to live vegetation, there are no spark-over formulas currently derived expressly for vegetation to conductor minimum distances. Therefore the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice. The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

**Comparison of spark-over distances computed using Gallet wet equations vs.  
IEEE 516-2003 MAID distances**

( AC ) Nom System Voltage (kV)	( AC ) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 feet	Table 7 (Table D.5 for feet) IEEE 516-2003 MAID (ft) @ Alt. 3000 feet
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

## Standard PRC-004-2.1 – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

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### A. Introduction

1. **Title:** Analysis and Mitigation of Transmission and Generation Protection System Misoperations
2. **Number:** PRC-004-2.1
3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.
4. **Applicability**
  - 4.1. Transmission Owner.
  - 4.2. Distribution Provider that owns a transmission Protection System.
  - 4.3. Generator Owner.
5. **(Proposed) Effective Date:** In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements become effective upon Board of Trustees' adoption.

### B. Requirements

- R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- R2. The Generator Owner shall analyze its generator and generator interconnection Facility Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.

### C. Measures

- M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Entity's procedures.

### D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Enforcement Authority**

Regional Entity.

## Standard PRC-004-2.1 – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

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### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

### 1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

### 1.4. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation or generator interconnection Facility Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

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

### 1.5. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

## 2. Violation Severity Levels (no changes)

### E. Regional Differences

None identified.

### Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	<ol style="list-style-type: none"> <li>1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>2. Added “periods” to items where appropriate.</li> </ol> Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
2	TBD	Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised.
2.1	XX	Errata change: Edited R2 to add “...and generator interconnection Facility...”	Revision under Project 2010-07

## Standard PRC-004-2.1 – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

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### A. Introduction

1. **Title:** Analysis and Mitigation of Transmission and Generation Protection System Misoperations
2. **Number:** PRC-004-2.1
3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.
4. **Applicability**
  - 4.1. Transmission Owner.
  - 4.2. Distribution Provider that owns a transmission Protection System.
  - 4.3. Generator Owner.
5. **(Proposed) Effective Date:** In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements become effective upon Board of Trustees' adoption.

### B. Requirements

- R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- R2. The Generator Owner shall analyze its generator and generator interconnection Facility Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.

### C. Measures

- M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Entity's procedures.

### D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Enforcement Authority**

Regional Entity.

## Standard PRC-004-2.1 – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

### 1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

### 1.4. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation or generator interconnection Facility Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

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

### 1.5. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

## 2. Violation Severity Levels (no changes)

### E. Regional Differences

None identified.

### Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	<ol style="list-style-type: none"> <li>1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>2. Added “periods” to items where appropriate.</li> </ol> Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
2	TBD	Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised.
<u>32.1</u>	XX	Errata change: Edited R2 to add “...and generator interconnection Facility...”	Revision under Project 2010-07

## Standard PRC-004-2.1 – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

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### A. Introduction

1. **Title:** Analysis and Mitigation of Transmission and Generation Protection System Misoperations
2. **Number:** PRC-004-2.1
3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.
4. **Applicability**
  - 4.1. Transmission Owner.
  - 4.2. Distribution Provider that owns a transmission Protection System.
  - 4.3. Generator Owner.
5. **(Proposed) Effective Date:** ~~The first day of the first calendar quarter, one year after applicable~~ In those jurisdictions where regulatory approval; or in is required, all requirements become effective upon approval. ~~In those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year after~~ all requirements become effective upon Board of Trustees' adoption. \_\_

### B. Requirements

- R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- R2. The Generator Owner shall analyze its generator and generator interconnection Facility Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.

### C. Measures

- M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Entity's procedures.

### D. Compliance

1. **Compliance Monitoring Process**

**Standard PRC-004-2.1 – Analysis and Mitigation of Transmission and Generation Protection System Misoperations**

**1.1. Compliance Enforcement Authority**

Regional Entity.

**1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

**1.3. Compliance Monitoring and Enforcement Processes:**

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

**1.4. Data Retention**

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation or generator interconnection Facility Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

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

**1.5. Additional Compliance Information**

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

**2. Violation Severity Levels (no changes)**

**E. Regional Differences**

None identified.

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
2	TBD	Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised.
<u>2.1</u>	<u>XX</u>	<u>Errata change: Edited R2 to add “...and</u>	<u>Revision under Project</u>



**Standard PRC-004-2.1 – Analysis and Mitigation of Transmission and Generation Protection System Misoperations**

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		<u>generator interconnection Facility...”</u>	<u>2010-07</u>
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## Implementation Plan for FAC-001-1—Facility Connection Requirements

### **Prerequisite Approvals**

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

### **Revision to Sections of Approved Standards and Definitions**

There are no proposed revisions to requirements in other already approved standards. FAC-001-0 – Facility Connection Requirements will be retired at midnight the day before FAC-001-1 becomes effective.

### **Compliance with Standard**

Since this version of the standard imposes no changes to Transmission Owners from those in the FERC-approved version of the standard, the expectation is that Transmission Owners will maintain their current state of compliance. Thus, the standard is effective for Transmission Owners upon approval, as detailed below.

The proposed changes to the FERC-approved version of this standard only address Generator Owner applicability and requirements (add Generator Owner to section 4.2, introduce a new requirement (R2), and modify one existing requirement (now R3)). Therefore, this implementation plan only identifies a compliance timeframe for Generator Owners to which this standard will apply.

### **Effective Date**

There are two effective dates associated with this standard:

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner and Regional Entity become effective upon Board of Trustees' adoption.

In those jurisdictions where regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities. In those jurisdictions where no regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after Board of Trustees' adoption.

# Implementation Plan for FAC-003-3— Transmission Vegetation Management

## Prerequisite Approvals

There are a number of scenarios that could occur regarding the approval of FAC-003-2 that would affect the implementation of FAC-003-3.

If FAC-003-2 is filed with applicable regulatory authorities and approved before FAC-003-3 is filed with applicable regulatory authorities, then when and if FAC-003-3 is approved by applicable regulatory authorities, the implementation plan and effective dates for Transmission Owners in FAC-003-2 will be transferred into this implementation plan. The “clock” for calculating effective dates for Transmission Owners will still have started at the time specified in FAC-003-2 (based on the approval date of that standard). Generator Owners will be required to comply with the implementation plan as outlined below.

If applicable regulatory authorities elect to approve only FAC-003-3 and not FAC-003-2, the original implementation plan for Transmission Owners as outlined in FAC-003-2 will be transferred into this implementation plan. Generator Owners will be required to comply with the implementation plan as outlined below. The “clocks” for calculating the effective dates for both Transmission Owners and Generator Owners will begin at the same time.

If applicable regulatory authorities approve FAC-003-2 and FAC-003-3 at the same time, the implementation plan and effective dates for Transmission Owners in FAC-003-2 will be transferred into this implementation plan and FAC-003-2 will be immediately retired. Generator Owners will be required to comply with the implementation plan as outlined below. The “clocks” for calculating the effective dates for both Transmission Owners and Generator Owners will begin at the same time.

## Revision to Sections of Approved Standards and Definitions

There are no proposed revisions to requirements in other already approved standards. All requirements and the two revised definitions in the proposed standard FAC-003-2 will be retired at midnight the day before FAC-003-3 becomes effective.

There are two revised definitions in the proposed standard:

### Right-of-Way (ROW)

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either

construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria.

### **Vegetation Inspection**

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

There is one new definition in the proposed standard:

### **Minimum Vegetation Clearance Distance (MVCD)**

The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

The current glossary definitions of Right-of-Way and Vegetation Inspection, or the glossary definitions of Right-of-Way and Vegetation Inspection in FAC-003-2, if that standard has been approved, will be retired at midnight the day before FAC-003-3 (and with it, the above definitions of Right-of-Way and Vegetation Inspection) becomes effective. The above definition of Minimum Vegetation Clearance Distance will be added to the NERC glossary upon approval of FAC-003-3, or the above definition of Minimum Vegetation Clearance Distance will replace (and thus force the retirement, at midnight the day before FAC-003-3 is approved) of the same definition in FAC-003-2, if FAC-003-2 has been approved.

### **Compliance with Standard**

As outlined above under "Prerequisite Approvals," the inclusion of Transmission Owners in this implementation plan will depend on order in which regulatory authorities approved FAC-003-2 and FAC-003-3. Therefore, this implementation plan only identifies a compliance timeframe for Generator Owners to which this standard will apply.

To reach compliance with the standard, a Generator Owner will have to perform a full review of as-built drawings and determine which generation interconnection Facilities require a Transmission Vegetation Management Plan (TVMP) and inspection as specified by NERC Reliability Standard FAC-003-3. In general, Generator Owners do not have staff that are qualified and experienced to create a TVMP, perform Right-of-Way inspections, and perform any required tree trimming (as is required by FAC-003-3 Requirement 1.3). Once a complete inventory is created, the Generator Owner will begin the process of gathering information for the TVMP. In instances where the generation interconnection Facilities are owned by a partnership, a majority or operating partner will need to obtain partnership

approval to proceed with procurement of a TVMP expert, and later a tree trimming crew. Typically, a request for proposal to hire TVMP consultant is initiated which could take several weeks in order to obtain sufficient bids (and also satisfy Sarbanes Oxley requirements). Once all bids have been received, a contract with a TVMP consultant is signed. At this point, the TVMP consultant and Generator Owner staff will develop the TVMP, which needs to take into account local growth conditions, types of vegetation and other aspects required by FAC-003. Once the TVMP is developed, Generator Owner staff and the TVMP consultant will need to perform a Right-of-Way inspection (as required in FAC-003-3 Requirement 1), usually done using GPS, LIDAR and other tools by experienced and qualified staff.

Once a Right-of-Way inspection is completed and clearances are required, the Generator Owner will need to issue a request for proposal to hire a tree trimming crew that is qualified and experienced to perform required clearance trimming. Once all bids have been received, a contract with a tree trimming crew is signed. When the tree trimming crew is acquired, the crew will need to familiarize themselves with the entity's TVMP and required clearances. The Generator Owner will typically need to schedule any required outages in order for the tree trimming crew to perform the needed clearance trimming. This action would also include the implementation of the work plan as required in FAC-003-3 Requirement 2. During scheduled outages, if required, the tree trimming crew will perform any required clearances and document the activities.

Another typical action is the Generator Owner establishing a system for maintaining TVMP-related activities, including maintenance of inspection and clearance documentation (as required in FAC-003-3 Requirement 1.2). On an ongoing basis, in addition to performing inspections and clearances as required by the entity's TVMP, the Generator Owner will need to ensure that the training and qualification requirements for the standard are met. The entity will also need to maintain documentation of all FAC-003-3 activities for compliance period of one year to meet compliance with the standard.

Again, due to a typical lack of experience and qualifications required by FAC-003-3, compliance with this standard by a Generator Owner may take as long as two years – in part because many entities will have generator interconnection Facilities in various parts of the country which may require several instances of TVMP and numerous Right-of-Way inspections.

### **Effective Date**

There are two effective dates associated with this implementation plan:

The first effective date allows Generator Owners time to develop documented maintenance strategies or procedures or processes or specifications as outlined in Requirement R3.

In those jurisdictions where regulatory approval is required, Requirement R3 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one

year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The second effective date allows entities time to comply with Requirements R1, R2, R4, R5, R6, and R7.

In those jurisdictions where regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.
2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.
3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.
4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.
5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12

months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

## **Implementation Plan for FAC-003-X – Transmission Vegetation Management Program**

### **Prerequisite Approvals**

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

### **Revision to Sections of Approved Standards and Definitions**

There are no proposed revisions to requirements in other already approved standards. FAC-003-1 will be retired at midnight the day before FAC-003-X becomes effective.

There is one revised definition in the proposed standard:

**Right-of-Way:** A corridor of land on which electric lines may be located. The Transmission Owner or applicable Generator Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

The current glossary definition of Right-of-Way will be retired at midnight the day before FAC-003-X (and with it, the above definition of Right-of-Way) becomes effective.

### **Compliance with Standard**

There are no changes to the requirements applicable to Transmission Owners already in effect in FAC-003-1, and the expectation is that Transmission Owners will maintain their current state of compliance. Thus, the standard is effective for Transmission Owners upon approval, as detailed below.

The proposed changes to FAC-003-1 only address Generator Owner applicability and requirements (add Generator Owner to section 4.3 and add applicable Generator Owner to all requirements). Therefore, this implementation plan only identifies a compliance timeframe for Generator Owners to which this standard will apply.

To reach compliance with the standard, a Generator Owner will have to perform a full review of as-built drawings and determine which generation interconnection Facilities require a Transmission Vegetation Management Plan (TVMP) and inspection as specified by NERC Reliability Standard FAC-003-X. In general, Generator Owners do not have staff that are qualified and experienced to create a TVMP and implement annual plans for vegetation management. Once a complete inventory is created, the Generator Owner will begin the process of gathering information for the TVMP. In instances where the generation interconnection Facilities are owned by a partnership, a majority or operating partner will need to obtain partnership approval to proceed with procurement of a TVMP expert, and later a tree trimming crew. Typically, a request for proposal to hire TVMP consultant is initiated, which could take several weeks in order to obtain sufficient bids (and also satisfy Sarbanes Oxley requirements). Once all bids have been received, a contract with a TVMP consultant is signed. At this point, the TVMP consultant and



Generator Owner staff will develop the TVMP, which needs to take into account local growth conditions, types of vegetation and other aspects required by FAC-003-X. Once the TVMP is developed, Generator Owner staff and the TVMP consultant will need to perform a Right-of-Way inspection, usually done using GPS, LIDAR and other tools by experienced and qualified staff.

Once a Right-of-Way inspection is completed and clearances are required, the Generator Owner will need to issue a request for proposal to hire a tree trimming crew that is qualified and experienced to perform required clearance trimming. Once all bids have been received, a contract with a tree trimming crew is signed. When the tree trimming crew is acquired, the crew will need to familiarize themselves with the entity's TVMP and required clearances. The Generator Owner will typically need to schedule any required outages in order for the tree trimming crew to perform the needed clearance trimming. This action would also include the implementation of the work plan. During scheduled outages, if required, the tree trimming crew will perform any required clearances and document the activities.

Another typical action is the Generator Owner establishing a system for maintaining TVMP-related activities, including maintenance of inspection and clearance documentation. On an ongoing basis, in addition to performing inspections and clearances as required by the entity's TVMP, the Generator Owner will need to ensure that the training and qualification requirements for the standard are met. The entity will also need to maintain documentation of all FAC-003-X activities for compliance period of one year to meet compliance with the standard.

Again, due to a typical lack of experience and qualifications required by FAC-003-X, compliance with this standard by a Generator Owner may take as long as two years – in part because many entities will have generator interconnection Facilities in various parts of the country which may require several instances of TVMP and numerous Right-of-Way inspections.

### **Effective Date**

There are three effective dates associated with this implementation plan:

The first effective date applies to Transmission Owners.

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner become effective upon Board of Trustees' adoption.

The second effective date allows Generator Owners time to prepare a formal transmission vegetation management program as outlined in Requirement R1.

In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R1 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The third effective date allows entities time to comply with Requirements R2, R3, and R4.

In those jurisdictions where regulatory approval is required, Requirements R2, R3, and R4 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R2, R3, and R4 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

# Implementation Plan for PRC-004-2.1— Analysis of Transmission and Generation Protection System Misoperations

## **Prerequisite Approvals**

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

## **Revision to Sections of Approved Standards and Definitions**

There are no proposed revisions to requirements in other already approved standards. PRC-004-2 will be retired when PRC-004-2.1 becomes effective.

## **Compliance with Standard**

The proposed change to Requirement R2 is a clarifying change. While there was no reliability gap in the previous version of the standard, if applied literally, there was the possibility for the misperception that the Generator Owner was only responsible for analyzing its generator Protection System Misoperations, exclusive of its generator interconnection Facility. The errata change to R2 makes clear that generator interconnection Facilities are also part of Generator Owners' responsibility in the context of this standard.

Because the change is merely a clarifying change, no additional time for compliance is needed.

## **Effective Date**

In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements become effective upon Board of Trustees' adoption.

# Technical Justification Resource Document

## Project 2010-07 Generator Requirements at the Transmission Interface

### Background

As part of its work on Project 2010-07—Generator Requirements at the Transmission Interface, the standard drafting team (SDT) reviewed 34 reliability standards and 102 requirements to determine what changes are necessary to close a reliability gap with respect to what is commonly known as the generator interconnection Facility. Many of these standards and requirements had been addressed in the [Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface](#) (Ad Hoc Report) and additional standards were reviewed as a result of informal discussions with NERC and FERC staffs.

The basis for standard modifications recommended by the Ad Hoc Group for Generator Requirements at the Transmission Interface (Ad Hoc Group) was a few fundamental clarifications to the definitions of Generator Owner, Generator Operator, and Transmission, along with the creation of new definitions: one for Generator Interconnection Facility and one for Generator Interconnection Operational Interface. The Ad Hoc Group proposed the addition of these two new definitions to 26 standards encompassing 29 requirements (new and old), along with some modifications to FAC-003 to make it applicable to Generator Owners under certain circumstances.

Since the publication of the Ad Hoc Report, various entities have challenged these modifications and the recommended creation of the new definitions. The SDT has developed a more focused approach than that of the Ad Hoc Group: to propose recommendations whereby sole-use interconnection Facilities (at or above 100 kV) that are owned and operated by generating entities will be included in a small set of standards and requirements previously only applicable to Transmission Owners. The SDT agrees completely with the Ad Hoc Group's conclusion that Generator Owners and Operators of these sole-use generator tie-line Facilities (at voltages equal to or greater than 100 kV) should not be registered as Transmission Owners and Transmission Operators in order to maintain reliability on the Bulk Electric System (BES).

The SDT's justification for this strategy is rooted in the very title of its standards project: "Generator Requirements at the Transmission Interface." That is, the goal and scope of the project has always been to determine the responsibilities of those Generator Owners and Generator Operators that own or operate an interconnection Facility (in some cases labeled a "transmission Facility") between the generator and the interface with the portion of the BES where Transmission Owners and Transmission Operators take over ownership and operating responsibility. These kinds of Generator Owners and Generator Operators do not own or operate Facilities that are part of the interconnected system; rather, they own and operate sole-use Facilities that are connected to the boundary of the

interconnected system and as such have a limited role in providing reliability compared to those that operate in a networked fashion beyond the point of interconnection.

While some argue that these interconnecting portions of a Generator Owner's Facilities could be defined as Transmission and thus require the Generator Owner and Generator Operator for the Facility to be classified and registered as a Transmission Owner and Transmission Operator, the SDT does not believe this is necessary to provide an appropriate level of reliability for the BES. Just as important, such classification and registration could actually cause a reduction in reliability. Generator Owners and Generator Operators do not need, and in some cases may be prohibited from having, a wide-area view and responsibility for the integrated transmission system. Requiring Generator Owners and Generator Operators to have such responsibilities would require significant training, require substantially more data and modeling responsibilities, and detract from the entities' primary functions: to own and operate their generation equipment – including any Facilities owned and operated at voltages of 100 kV or greater that connect to the interconnected system – in a reliable manner.

Additionally, the SDT believes that the industry is much more aware today of the need to include *all* elements (owned and operated at 100 kV or higher) of a generator Facility in the procedures and compliance program of the registered entity that owns or has operational responsibility of those elements. Industry awareness was raised substantially at the time the [October 17, 2010 Facility Ratings Recommendation to Industry](#) was issued (which included Generator Owners and specifically addressed interconnection Facilities in [the Q&A document](#) with the statement that the alert applied to generator interconnection tie lines that are radial only and do not serve load “if the generator is considered part of the bulk electric system”). While this applies to a specific NERC Recommendation, the SDT considers this compelling evidence that the paradigm for thinking about generator interconnection Facilities is shifting.

All of this has led the SDT to its current conclusions to modify FAC-001, FAC-003, and PRC-004 and later, PRC-005. The SDT does not believe any further modifications to standards are necessary to maintain an appropriate level of reliability based on the revised assumption that while generator Facilities (at 100 kV and above) will be considered by some to be transmission, Generator Owners and Generator Operators should not be registered as Transmission Owners and Transmission Operators simply as a result of the ownership and operation of such Facilities. Because the majority of commenters support the SDT's current recommendation to not adopt new terms, the SDT has elected to focus on its standard changes and not, at this time, propose revisions to existing, or creation of new, glossary terms.

Below, the SDT discusses the changes it has proposed for FAC-001, FAC-003, and PRC-004 and the changes it plans to propose for PRC-005 and then provides justification for not modifying any of the additional standards and requirements it has reviewed.

## Review of SDT's Proposed Standard Changes

### ***FAC-001-1—Facility Connection Requirements***

While some stakeholders have questioned the modifications in the proposed FAC-001-1, the SDT remains convinced that there is the potential for a reliability gap if this standard is not modified so that it applies to a Generator Owner *if and when it executes an Agreement* to evaluate the reliability impact of interconnecting a third party Facility to its existing generation interconnection Facility. The intent of this modified language is to start the compliance clock when the Generator Owner executes an Agreement to perform the reliability assessment required in FAC-002-1. This step is expected to occur if a Generator Owner is compelled by a regulatory body to allow such interconnection. Assuming that a regulatory body would require a Generator Owner to evaluate such an interconnection request, the SDT expects the Generator Owner and the third party to execute some form of an Agreement. The SDT intentionally excluded a specific reference to the form of Agreement (such as a feasibility study) in deference to stakeholder suggestions to avoid comingling of commercial and reliability issues in reliability standards.

The SDT acknowledges that the scenario described in the proposed FAC-001-1 may be rare, but in the past (for instance, FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities, and the SDT thinks it is important to clarify the responsibilities related to such a request in NERC's Reliability Standards. And, while the SDT acknowledges that such regulatory action might also result in the Generator Owner being registered for other functions, such as Transmission Owner, Transmission Planner, and/or Transmission Service Provider, it decided the proposed revision provides appropriate reliability coverage until any additional registration is required and does not impact any Generator Owner that never executes an Agreement as described in the standard.

### ***FAC-003-X and FAC-003-3—Vegetation Management***

The SDT and most stakeholders agree with the Ad Hoc Group recommendation that FAC-003 be applicable to Generator Owners that own a generation interconnection Facility if that Facility contains overhead conductors. The Ad Hoc Group originally excluded such a Facility from this requirement if its length is less than two spans (generally one half mile from the generator property line). The SDT agrees with that intended exclusion in principle; as it discusses in the document titled "[Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface](#)," the SDT recognizes that in many cases, generation Facilities are (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale for exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit.

Thus, the SDT has maintained this exception language but has modified it based on stakeholder input such that it excludes Facilities shorter than one mile which have a clear line of sight from the fenced area of the generating switchyard to the point of interconnection. Specifically, sections 4.3.1 of both versions of FAC-003 (which address applicable generation Facilities) now state: "Overhead transmission



lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...” The SDT took into consideration all comments submitted in both formal comment periods, and believes that this exemption now adequately addresses the reliability impact for a majority of the Facilities, while balancing the efforts necessary to support the standard from all entities.

#### ***PRC-004-2.1—Analysis and Mitigation of Transmission and Generation Protection System Misoperations***

After examining all standards it had previously reviewed, the SDT elected to propose a slight change to PRC-004-2.1. While the SDT rejected other opportunities to “drop” the phrase “generator interconnection Facility” into requirements because it is not typically the best way to add clarity, in the case of PRC-004-2, the SDT fears that the phrasing of R2 (“The Generator Owner shall analyze its generator Protection System Misoperations...”) could lead to some confusion about whether an interconnection Facility is included. Thus, the SDT proposes adding “and generator interconnection Facility” as redlined in the draft standard. Because there is no change in applicability, and because the SDT believes that most Generator Owners already interpret the standard in this manner, we consider this to be a minor and not substantive change employed only to add clarity.

#### ***PRC-005-1a—Transmission and Generation Protection System Maintenance and Testing***

In the concurrent 45-day comment and ballot period that ended in November 2011, several commenters pointed out that the wording in R1 and R2 of PRC-005-1a requires the same explicit reference to a generator interconnection Facility that was added in PRC-004-2.1 R2. The SDT agrees and is developing revisions to PRC-005-1a. These will be posted (separate from the recirculation ballot posting) soon.

#### **Review of Other Standards Considered by the Standard Drafting Team**

To ensure that no reliability gaps were left when the SDT shifted its strategy from the original strategy of the Ad Hoc Group, the SDT reviewed all standards for which the Ad Hoc Group had proposed changes, and again discussed whether making these standards applicable to Generator Owners or Generator Operators would increase reliability with respect to generator requirements at the transmission interface. During the 45-day concurrent comment and ballot period that ended in November 2011, the SDT also received comments from NERC staff encouraging it to review additional standards that NERC staff had proposed to apply to Generator Owners and Generator Operators in [NERC Compliance Process Directive #2011-CAG-001 Regarding Generator Transmission Leads](#) (Directive). Similarly, stakeholder commenters encouraged the SDT to review standards cited in FERC’s Order Denying Compliance Registry Appeals of Cedar Creek Wind Energy and Milford Wind Corridor Phase I (135 FERC ¶ 61,241) (FERC Order).

The SDT reviewed all of these standards and requirements again and continues to find clear and technical reliability-based reasons that support not adding Generator Owner and Generator Operator requirements to the standards. The chart below indicates where else (the Ad Hoc Report, the NERC Directive, or the FERC Order) the standards addressed were discussed. While both the NERC Directive and FERC Orders address specific requirements within these standards, the SDT has found it useful to address each standard as a whole. Often, requirements within a standard, or even from standard to standard, work in concert to ensure that there are no reliability gaps, whereas a review of a requirement in isolation might give the impression that there is gap.

Standard	Ad Hoc Report*	NERC Directive	FERC Order
EOP-003-1	X		
EOP-005-1		X	
FAC-001-0		X	
FAC-003-1 or FAC-003-2	X	X	X
FAC-014-2		X	X
IRO-005-2	X		
PER-001-0	X		
PER-002-0	X	X	
PER-003-1			X
PRC-001-1		X	X
TOP-001-1	X	X	X
TOP-004-2	X	X	X
TOP-006-1		X	
TOP-008-1	X		

\*This chart and accompanying document only address those standards in the Ad Hoc Report for which substantive changes (change in applicability or the addition of a new requirement) were proposed.

The SDT acknowledges that both NERC and FERC have stated that neither the NERC Directive nor the FERC Order is intended to prejudge the work of the SDT. The SDT also acknowledges that the discussion in the FERC Order is related to specific cases in which certain entities will actually be registered as Transmission Owners and Transmission Operators, a process that is distinct from the SDT’s work, which assumes that once this project is complete, Generator Owners and Generator Operators will not be registered for any other functions based on ownership of a sole-use generator interconnection Facility. Still, because these related efforts are ongoing, the SDT thought it would be useful to directly address some of the discussion in the Directive and the Order. The rest of this document provides the SDT’s technical justification for limiting the scope of its work to FAC-001, FAC-003, PRC-004, and PRC-005.

***EOP-003-1—Load Shedding Plans (addressed in the Ad Hoc Report)***



For EOP-003-1, the Ad Hoc Group originally proposed that Generator Operators be added to the requirement that requires Transmission Operators and Balancing Authorities to coordinate automatic load-shedding throughout their areas. The SDT determined that this addition was unnecessary because PRC-001 already includes the requirement that Transmission Operators coordinate their underfrequency load shedding programs with underfrequency isolation of generating units, which implies that Generator Operators need to provide their underfrequency settings to their respective Transmission Operator. Further, Generator Operators typically do not have the technical expertise or access to the data necessary for the high-level coordination that this standard requires.

***EOP-005-1—System Restoration Plans (addressed in the NERC Directive)***

In its Directive, NERC staff states the following by way of rationale for applying EOP-005-1 Requirements R1, R2, R5, R6, and R7 to Generator Operators:

“If GOP has blackstart capability, then EOP-005 applies, GOP restoration plan would require coordination with TOP per the TOP Blackstart Restoration Plan. The GOP would start its blackstart resources to provide necessary real and reactive power to its generating resources per interconnecting TOP directives. In addition, if GOP has blackstart capability the interconnection TOP will have included this capability in its restoration planning for its area of responsibility. If GOP does not have blackstart capability, GOP restoration plan is dependent upon provision of real and reactive power service from interconnecting TOP, per VAR-001 and VAR-002 requiring the GOP to follow the directives of the interconnecting TOP, compliance with this standard/requirements is not required.”

Blackstart capability of a generating unit is unrelated to owning or operating transmission Facilities or a generation interconnection Facility. During a system restoration event, Generator Operators provide real and reactive power to the BES only at the direction of a Transmission Operator. The Generator Operators are not providing Transmission Operator services through their blackstart Facilities. In addition, many units with blackstart capability are not included in a TOP System Restoration Plan.

In FERC Order 693, paragraph 630, FERC approved EOP-005-1 and found the standard “adequately addresses operating personnel training and system restoration plans to ensure that transmission operators, balancing authorities and reliability coordinators are prepared to restore the Interconnection following a blackout. Accordingly, the Commission approves Reliability Standard EOP-005-1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP-005-1 through the Reliability Standards development process that identifies time frames for training and review of restoration plan requirements.”

FERC also specifically addressed system restoration training concerns and requirements in FERC Order 693 in its review and approval of Reliability Standard EOP-005-1. In that order, FERC stated that

personnel outside a control room should be trained in system restoration, but also that this should be included in a system restoration Reliability Standard, as follows:

627. With regard to comments that the Commission's concerns are being addressed in NERC's drafting of proposed PER-005-1 Reliability Standard on operator training, we note PER-005-1 only includes Requirements on the control room personnel and not those outside of the control room. System restoration requires the participation of not only control room personnel but also those outside of the control room. These include blackstart unit operators and field switching operators in situations where SCADA capability is unavailable. As such, the Commission believes that inclusion of periodic system restoration drills and training and review of restoration plans in a system restoration Reliability Standard is the most effective way of achieving the desired goal of ensuring that all participants are trained in system restoration and that the restoration plans are up to date to deal with system changes.

Thus, FERC clearly found that the existing standard EOP-005-1 adequately addressed operating personnel training and would ensure the restoration of the BES in the event of a blackstart, and further directed that any modifications be addressed through the Reliability Standard Development Process.

Pursuant to Order 693, NERC initiated Project 2006-03, and empowered the System Restoration and Blackstart Standard Drafting Team (SRBSDT) to modify the related standards. The SRBSDT developed Reliability Standard EOP-005-2, which includes Generator Operator system restoration requirements including training, restoration plans, drills, and testing of blackstart resources. In Order 749, FERC approved EOP-005-2, which included its approval of the implementation plan for EOP-005-2. Again, both FERC and NERC had the opportunity to identify issues with the implementation time of EOP-005-2 and declined to do so.

5. Currently effective Reliability Standard EOP-005-1 requires transmission operators, balancing authorities, and reliability coordinators to have a restoration plan, test the plan, train operating personnel in the restoration plan, and have the ability to restore the Interconnection using the plans following a blackout. In Order No. 693, the Commission directed the ERO to develop, through the Reliability Standard development process, a modification to EOP-005-1 that identifies time frames for training and review of restoration plan requirements to simulate contingencies and prepare operators for anticipated and unforeseen events . . .

Also, in FERC Order 749, both NERC and FERC identified the modifications to EOP-005 as "improvements" to the standard, not changes to close a reliability gap:

10. NERC states that the proposed Reliability Standards "represent significant revision and improvement from the current set of enforceable standards" and address the Commission's directives in Order No. 693 related to the EOP standards. NERC explains that, among other

enhancements, “[t]he proposed revisions now clearly delineate the responsibilities of the Reliability Coordinator and Transmission Operator in the restoration process and restoration planning.” NERC describes the proposed Reliability Standards as providing “specific requirements for what must be in a restoration plan, how and when it needs to be updated and approved, what needs to be provided to operators and what training is necessary for personnel involved in restoration processes.

17. . . . By enhancing the rigor of the restoration planning process, the Reliability Standards represent an improvement from the current Standards and will improve the reliability of the Bulk-Power System. . . .

In summary, the Generator Operator blackstart requirements have been already been appropriately addressed through the Reliability Standards Development Process. EOP-005-2 will become effective in 2013 as approved by both the NERC Board of Trustees and FERC. There is no existing reliability gap related to owning a generation interconnection Facility and Standard EOP-005-1.

***FAC-014-2—Establish and Communicate System Operating Limits (addressed in the NERC Directive and the FERC Order)***

FAC-014-2, R2 states “The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator’s SOL Methodology.”

In its Directive, NERC states, with respect to FAC-014-2: “In the event an RC directs the establishment of an SOL, the SOL must be established in accordance with the RC’s SOL Methodology.”

In paragraphs 68 and 84 of the FERC Order, FERC states that without compliance with FAC-014, R2, the entity in questions could “avoid establishing the system operating limit for its line or be allowed to establish an operating limit for its line that is not consistent with the requirements of the reliability coordinator’s methodology.”

The SDT does not believe that FAC-014-2 R2 should be revised to include Generator Operators. The Generator Owner is required by the FERC-approved versions of FAC-008-1 R1 and FAC-009-1 and pending FAC-008-3 R1, R2, and R6 (which has been filed for approval with FERC) to document the Facility Ratings for a Generator Owner-owned generator interconnection circuit greater than 100kV. The established Facility Rating must respect the most limiting applicable equipment rating in the circuit and must consider operating limitations and ambient conditions. The thermal or ampere rating of this circuit would equal its ampere operating limit and should be conveyed by the Generator Owner to the Generator Operator if they are not the same entity. The operating voltage limits for this circuit are established by the applicable Transmission Owner or Transmission Operator, not the Generator Owner or Generator Operator.

Therefore, we believe adding the Generator Owner to FAC-014-2 R2 would be redundant. What's more, the SDT is concerned that entities with a limited view of the system should not be setting IROLs or SOLs. We believe this should be the responsibility of entities with a wide-area view, as shown in the standard today; otherwise, we are concerned that reliability may be jeopardized. Commenters – including one from the Transmission Owner segment – have offered this same justification.

***IRO-005-2—Reliability Coordination – Current Day Operations (addressed in the Ad Hoc Report)***

The SDT chose not to adopt the revision to IRO-005-2 proposed by the Ad Hoc Group. This revision would have added a new requirement that would read, “The Generator Operator shall immediately inform the Transmission Operator of the status of the Special Protection System, including any degradation or potential failure to operate as expected for SPS relay or control equipment under its control.” The SDT initially determined that IRO-005-2 did not require modification because of the October 2011 retirement of the standard. In subsequent meetings, the SDT also reached the conclusion that there is no reliability gap as PRC-001-1 R2 already requires the Generator Operator to notify reliability entities of relay or equipment failures. The SDT believes that a Special Protection System is a form of protection system and therefore any degradation or potential failure to operate as expected would be required to be reported by the Generator Operator to reliability entities (Balancing Authorities, Transmission Operators, and Reliability Coordinators).

***PER Standards (PER-001-0 and PER-002-0 were addressed in the Ad Hoc Report; PER-002-0 was addressed in the NERC Directive; and PER-003-1 was addressed in the FERC Order)***

The Ad Hoc Group had proposed changes to PER-001-0—Operating Personnel Responsibility and Authority and PER-002-0—Operating Personnel Training. For PER-001-0, the Ad Hoc Group proposed adding a new R2 that would read “Each Generator Operator shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Generation Facility and Generation Interconnection Facility, and the responsibility and authority to follow the directives of reliability authorities including the Transmission Operator and Balancing Authority.” To PER-002-0, the Ad Hoc Group proposed adding the Generator Operator to R1 (“Each Transmission Operator, Generator Operator, and Balancing Authority shall be staffed with adequately trained operating personnel”) and adding a new R3 that would read: “Each Generator Operator shall implement an initial and continuing training program for all operating personnel that are responsible for operating the Generator Interconnection Facility that verifies the personnel’s ability and understanding to operate the equipment in a reliable manner.”

In its Directive, NERC does not address PER-001-0, but it states the following with respect to PER-002-0:

“The registered entity will develop an appropriate training program that contains the necessary elements for the GO/GOP operating a transmission facility to understand fully the impacts of the operation on the BPS, such as equipment involved, including protection systems, the

coordination aspects with the TO/TOP to which it is connected, and the protocols for and impacts of operating facilities associated with the transmission facility. The objective of this training is to ensure that the GO/GOP is completely aware of its obligations to follow the directives of the appropriate TOP and has personnel with the skills and training to execute these obligations in the best interest of reliability.”

These proposed changes to the PER standards have little to do with responsibilities that relate specifically to a generator interconnection Facility. Issues related to the training of Generator Operators existed separately from the work of Project 2010-07, and the SDT agrees that its scope limits its efforts to standards that are directly related to generator requirements at the transmission interface. The SDT also cites past FERC Orders as proof that this issue is not within the scope of Project 2010-07. In Order 693, FERC directed NERC to "expand the applicability of the personnel training Reliability Standard, PER-002-0, to include (i) generator operators centrally-located at a generation control center with a direct impact on the reliable operation of the Bulk-Power System..." In Order 742, FERC reaffirmed this, stating that it is "not modifying the Order No. 693 directive regarding training for certain generator operator dispatch personnel, nor are we expanding a generator operator's responsibilities.”

Centrally-located generator operators working at a generation control center typically dispatch the output from multiple generating units. As such, they can be called upon to comply with orders from their Balancing Authority that may have a significant impact on the reliable operation of the BES. Their training would be covered by proposed changes to PER-002-0 and Order 742. Generator Operators who deal with interconnection Facilities at individual generating plants, on the other hand, typically do not receive reliability-based orders specific to the interconnection Facilities and are therefore not covered by Order 742. Further, the SDT believes there is no reliability gap as TOP-001-1 R3 already requires Generator Operators to follow the directives of the appropriate Transmission Operators.

These training-related items are clearly important ones for the Commission, but the SDT does not think it is appropriate to fold modifications to these PER standards into the scope of its work unless it is specifically directed to do so. For now, modifications to PER-002-0 based on Order 693 directives are already included in [NERC's Issue Database](#) (P. 52-53) to be addressed by a future project. PER-001-0 is not addressed in the Issues Database, but the [Project 2007-03 drafting team has proposed](#) that the standard be retired.

The FERC Order does not address PER-001-0 or PER-002-0, but it does address PER-003-1. In paragraphs 67 and 81 of the FERC Order, FERC expresses concern that operational control over the transmission line breakers owned by the entities in question are not under the control of NERC certified operators. FERC goes on to say that “Reliability Standard PER-003-001 requires NERC certification of all operators that have responsibility for the real-time operation of the interconnected Bulk Electric System. When switching the tie-line in or out of service, operators must have the

appropriate credentials and training to properly perform the switching and coordinate the switching to prevent adverse impacts such as the introduction of faults on the system.”

The SDT can find no evidence that the kinds of training requirements for operating the breakers of the generator interconnection Facility cited in the FERC Order exist elsewhere for other entities that operate breakers on lines. For instance, Transmission Owners that are not also Transmission Operators are not required to undergo any sort of training. The SDT does not mean to dismiss this issue altogether, and it may be that training should be expanded to include Generator Owners, Generator Operators, Transmission Owners, end users, and possibly others, but the development of such requirements would have implications far beyond the scope and expertise of this team.

***PRC-001-1—System Protection Coordination (addressed in the NERC Directive and the FERC Order)***

The NERC Directive addresses PRC-001-1 R2, R2.2, and R4. The FERC Order addresses these requirements, along with Requirement R6.

About R2 and R4, NERC’s Directive simply states: “PRC-001-R2 requires notification and corrective action for relay or equipment failure. R4 coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.”

In paragraphs 64 and 78 of the FERC Order, FERC expresses concern that “there is a risk of an adverse impact on reliability if the protection relays or protection systems on the [entity’s] line are not coordinated with those on the transmission network facilities in its area.”

Generator Operators and the scope of protection equipment for generation interconnection Facilities are already appropriately accounted for in this standard in requirement R2 and sub-requirement R2.2. The language used in R2 that applies to the Generator Operator uses the general terms “relay or equipment failures” which would include not only generator relaying, but generator interconnection relaying in the Generator Operator’s scope as well. The Generator Operator is required to notify the Transmission Operator and Host Balancing Authority in R2.1 “if a protective relay or equipment failure reduces system reliability.” Requirement R2.2 requires the affected Transmission Operator to notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. Thus, applying R2.2 to a Generator Operator would be redundant to R2.1. If a Generator Operator had a relay or equipment failure on its Facility, including its interconnection Facility it would be required to report that to its Transmission Operator under R2.1, and the Transmission Operator is then required to notify its Reliability Coordinator and other affected Transmission Operators and Balancing Authorities under R2.2.

PRC-001-1 R4 states, “Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission



Operators, and Balancing Authorities.” A sole-use generator interconnection Facility does not constitute a major transmission line or major interconnection with neighboring Generator Operators, Transmission Operators, and Balancing Authorities. Thus, R4 should not be revised to include Generator Operators. In general, any coordination that might be required is covered by the fact that the Transmission Operator that is connected to a major transmission lines or interconnection has the requirement to coordinate protection on the interconnection, and there is no reliability gap.

PRC-001-1 R6 states, “Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.” It is clearly the responsibility of the Transmission Operator and/or Balancing Authority to monitor the Special Protection System, as they are the entity with a wide-area view, not the responsibility of a Generator Owner/Generator Operator with a local-area view who happens to have generator interconnection Facilities in the area. The requirement focuses on the Transmission Operator and Balancing Authority monitoring the status of each Special Protection System *in their area*; there is no “area” for the Generator Operator to monitor. For these reasons, there is no need to make this requirement applicable to Generator Operators.

***TOP-001-1—Reliability Responsibilities and Authority (addressed in the Ad Hoc Report, NERC Directive, and FERC Order)***

Both the NERC Directive and the FERC Order discuss making TOP-001-1 R1 applicable to Generator Operators. About TOP-001-1, the NERC Directive simply states: “TOP-001-1 R1 ensures personnel assigned to operate BES transmission facilities have clear and unambiguous authority to operate those facilities.” With respect to R1, paragraphs 68 and 83 of FERC’s Order focus on ensuring that “system operators have the authority to take actions to maintain Bulk-Power System facilities within operating limits.”

TOP-001-1 R1 states, “Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.” TOP-001-1 R3 appropriately requires the GOP to comply with reliability directives issued by the Transmission Operator “unless such actions would violate safety, equipment, regulatory or statutory requirements.” These requirements effectively give the Transmission Operator the necessary decision-making authority over operation of all generator Facilities up to the point of interconnection. Thus, no changes to TOP-001-1 are necessary.

Additionally, the Ad Hoc Group proposed adding two new requirements to TOP-001-1. The first was proposed as R9 and read: “The Generator Operator shall coordinate the operation of its Generator Interconnection Facility with the Transmission Operator to whom it interconnects in order to preserve Interconnection reliability...” The SDT does not agree that TOP-001-1 needs to apply to Generator Operators in any form. TOP-002-2 R3 (proposed to be covered in the future by TOP-003-2, as outlined

in Project 2007-03's Implementation Plan) already requires the Generator Operator to coordinate its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. These entities are, in turn, required to coordinate with their respective Transmission Operator. Additionally, TOP-002-2 R4 (proposed to be covered in the future by TOP-003-2, as outlined in Project 2007-03's Implementation Plan) requires each Balancing Authority and Transmission Operator to coordinate with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator. With these requirements, Generator Operators are already required to provide necessary operations information to Transmission Operators. To require the same thing in TOP-001-1 would be redundant.

The second new requirement proposed by the Ad Hoc Group for TOP-001-1 was R10, which was to read: "The Transmission Operator shall have decision-making authority over operation of the Generator Interconnection Operational Interface at all times in order to preserve Interconnection reliability." As cited above, TOP-002-2 R3 (proposed to be covered in the future by TOP-003-2, as outlined in Project 2007-03's Implementation Plan) already requires the Generator Operator to coordinate with its interconnecting Transmission Operator. Further, TOP-001-1 R3 (proposed to be covered in the future in the proposed IRO-001-2 R2 and R3) already requires the Generator Operator to comply with reliability directives issued by the Transmission Operator. These requirements effectively give the Transmission Operator decision-making authority over operation of all generator Facilities up to the point of interconnection. To require the same thing in TOP-001-1 would be redundant.

***TOP-004-2—Transmission Operations (addressed in the NERC Directive and the FERC Order)***

Both the NERC Directive and the FERC Order address the application of TOP-004-2 R6 to Generator Operators. In its Directive, NERC simply states: "TOP-004-2 R6 ensures formal policies and procedures are formulated to provide for coordination of activities that may impact reliability." In paragraphs 67 and 82 of the FERC Order, FERC talks about entities ensuring the development of coordination protection to coordinate switching a generator interconnection Facility in and out of service, since different entities have control over different ends of the line. FERC concludes that for the entities in question, TOP-004-2 R6 must apply.

Requirement R6 and its sub-requirements state: "R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: R6.1. Monitoring and controlling voltage levels and real and reactive power flows, R6.2. Switching transmission elements, R6.3. Planned outages of transmission elements, R6.4. Responding to IROL and SOL violations."



TOP-001-1 R3 appropriately requires the Generator Operator to comply with reliability directives issued by the Transmission Operator. These requirements give the Transmission Operator the necessary decision-making authority over operation of all generator Facilities, including interconnection Facilities, up to the point of interconnection. Further, TOP-002-2 R3 requires the Generator Owner to coordinate its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. These entities are, in turn, required to coordinate with their respective Transmission Operators (also in TOP-002-2 R3). Each Balancing Authority and Transmission Operator is also then required to coordinate with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator (in TOP-002-2 R4). The coordination with which NERC and FERC are concerned is already addressed by these other requirements.

The Ad Hoc Group had proposed a new requirement, R7, for TOP-004-2 that would read: “The Generator Operator shall operate its Generator Interconnection Facility within its applicable ratings.” The SDT does not agree that a reliability gap exists, because an operator has a fiduciary obligation to protect a Facility for which it is operationally responsible. FAC-008-1—Facility Ratings Methodology and FAC-009-1—Establish and Communicate Facility Ratings already infer that the reason for establishing a ratings methodology and communicating Facility Ratings to the Reliability Coordinator, Planning Authority, Transmission Planner, and Transmission Operator is “...for use in reliable planning and operation of the Bulk Electric System.” Further, TOP-004-2 is proposed to be retired under the work of the Project 2007-03 drafting team. Its requirements will either be deleted or assigned elsewhere.

***TOP-006-1—Monitoring System Conditions (addressed in the NERC Directive; the SDT believes NERC intended to refer to TOP-006-2)***

Only the NERC Directive addresses TOP-006. It states: “TOP-006-1 R3 ensures technical information is provided to the responsible personnel; R6 ensures correct and accurate data to TOP and BA.” But PRC-001-1 R1 (“Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area”) addresses the necessary Generator Operator requirements with respect to TOP-006-2 R3. The SDT believes that knowledge of the purpose and limitations of protection system schemes applied in its area (required in PRC-001-1 R1) constitutes knowledge of “the appropriate technical information concerning protective relays” (required in TOP-006-1 R3).

TOP-006-2 R6 states “Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.” FAC-001-1 R2.1.6 already requires the Transmission Owner’s facility connection requirements to address “metering and telecommunications.” Any generator Facility that interconnected with a Transmission Owner would

have had to meet their Facility connection and system performance requirements for metering and telecommunications. Thus, there is no reliability gap.

***TOP-008-1—Response to Transmission Limit Violations (addressed in the Ad Hoc Report)***

Only the Ad Hoc Report addressed TOP-008-1, and it proposed a new requirement, R5, to TOP-008-1—Response to Transmission Limit Violations that would read “The Generator Operator shall disconnect the Generator Interconnection Facility when safety is jeopardized or the overload or abnormal voltage or reactive condition persists and generating equipment or the Generator Interconnection Facility is endangered. In doing so, the Generator Operator shall notify its Transmission Operator and Balancing Authority impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.” The SDT sees no reliability benefit to adding this requirement. TOP-001-1 R7 (“Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless...”) and its parts give the Generator Operator authority over its Facilities, which would include the generator interconnection Facility. If there is an outage, R7.1 requires the Generator Operator to notify and coordinate with its Transmission Operator, which is required to notify the Reliability Coordinator and other affected Transmission Operators. And as with TOP-004-2, the Project 2007-03 drafting team has proposed to delete all of TOP-008-1’s requirements and retiring the standard.

**Conclusion**

The Project 2010-07 SDT is confident that the changes it has proposed address the reliability gap that exists with respect to the responsibilities of Generator Owners and Generator Operations that own sole-use interconnection Facilities. The changes to FAC-001, FAC-003, and PRC-004 have been supported by stakeholders during comment periods, and there has been no strong support of technical justification provided for bringing other standards into the scope of this project.

# Technical Justification Resource Document

Project 2010-07 Generator Requirements at the Transmission Interface

## Background

As part of its work on Project 2010-07—Generator Requirements at the Transmission Interface, the standard drafting team (SDT) reviewed 34 reliability standards and 102 requirements to determine what changes are necessary to close a reliability gap with respect to what is commonly known as the generator interconnection Facility. ~~The majority~~ Many of these standards and requirements had been addressed in the [Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface](#) (Ad Hoc Report), and additional standards ~~have been~~ were reviewed, ~~and will continue to be reviewed,~~ as a result of informal discussions with NERC and FERC staffs.

The basis for standard modifications recommended by the Ad Hoc Group for Generator Requirements at the Transmission Interface (Ad Hoc Group) was a few fundamental clarifications to the definitions of Generator Owner, Generator Operator, and Transmission, along with the creation of new definitions: one for Generator Interconnection Facility and one for Generator Interconnection Operational Interface. The Ad Hoc Group proposed the addition of these two new definitions to 26 standards encompassing 29 requirements (new and old), along with some modifications to FAC-003 to make it applicable to Generator Owners under certain circumstances.

Since the publication of the Ad Hoc Report, various entities have challenged these modifications and the recommended creation of the new definitions. The SDT has developed a more focused approach than that of the Ad Hoc Group: to propose recommendations whereby ~~radial~~ sole-use interconnection Facilities (at or above 100 kV) that are owned and operated by generating entities will be included in a small set of standards and requirements previously only applicable to Transmission Owners. The SDT agrees completely with the Ad Hoc Group's conclusion that Generator Owners and Operators of these ~~radial~~ sole-use generator tie-line Facilities (at voltages equal to or greater than 100 kV) should not be registered as Transmission Owners and Transmission Operators in order to maintain reliability on the Bulk Electric System (BES).

The SDT's justification for this strategy is rooted in the very title of its standards project: "Generator Requirements at the Transmission Interface." That is, the goal and scope of the project has always been to determine the responsibilities of those Generator Owners and Generator Operators that own or operate an interconnection Facility (in some cases labeled a "transmission Facility") between the generator and the interface with the portion of the BES where Transmission Owners and Transmission Operators take over ownership and operating responsibility. These kinds of Generator Owners and Generator Operators do not own or operate Facilities that are part of the interconnected system; rather, they own and operate ~~radial~~ sole-use Facilities that are connected to the boundary of the

interconnected system and as such have a limited role in providing reliability compared to those that operate in a networked fashion beyond the point of interconnection.

While some argue that these interconnecting portions of a Generator Owner's Facilities could be defined as Transmission and thus require the Generator Owner and Generator Operator for the Facility to be classified and registered as a Transmission Owner and Transmission Operator, the SDT does not believe this is necessary to provide an appropriate level of reliability for the BES. Just as important, such classification and registration could actually cause a reduction in reliability. Generator Owners and Generator Operators do not need, and in some cases may be prohibited from having, a wide-area view and responsibility for the integrated transmission system. Requiring Generator Owners and Generator Operators to have such responsibilities would require significant training, ~~would~~ require substantially more data and modeling responsibilities, and ~~would~~ detract from the entities' primary functions: to own and operate their generation equipment – including any Facilities owned and operated at voltages of 100 kV or greater that connect to the interconnected system – in a reliable manner.

Additionally, the SDT believes that the industry is much more aware today of the need to include *all* elements (owned and operated at 100 kV or higher) of a generator Facility in the procedures and compliance program of the registered entity that owns or has operational responsibility of those elements. Industry awareness was raised substantially at the time the [October 17, 2010 Facility Ratings Recommendation to Industry](#) was issued (which included Generator Owners and specifically addressed interconnection Facilities in [the Q&A document](#)); ~~with the statement that the alert applied to generator interconnection tie lines that are radial only and do not serve load "if the generator is considered part of the bulk electric system"~~. While this applies to a specific NERC Recommendation, the SDT considers this compelling evidence that the paradigm for thinking about generator interconnection Facilities is shifting.

All of this has led the SDT to its current conclusions to modify FAC-001, FAC-003, and PRC-004; ~~and later, PRC-005~~. The SDT does not believe any further modifications to standards are necessary to maintain an appropriate level of reliability based on the revised assumption that while generator Facilities (at 100 kV and above) will be considered by some to be transmission, Generator Owners and Generator Operators should not be registered as Transmission Owners and Transmission Operators simply as a result of the ownership and operation of such Facilities. Because the majority of commenters support the SDT's current recommendation to not adopt new terms, the SDT has elected to focus on its standard changes and ~~to postpone discussions on not, at this time, propose~~ revisions to existing, or creation of new, ~~definitions until the standards have been successfully balloted.~~ [glossary terms](#).

Below, the SDT discusses the changes it has proposed for FAC-001, FAC-003, and PRC-004 and [the changes it plans to propose for PRC-005 and](#) then provides justification for not modifying any [of the](#)

additional standards ~~that had been proposed for substantive modification in the Ad Hoc Report and requirements it has reviewed.~~

## Review of SDT's Proposed Standard Changes

### ***FAC-001-1—Facility Connection Requirements***

While some stakeholders have questioned the modifications in the proposed FAC-001-1, the SDT remains convinced that there is the potential for a reliability gap if this standard is not modified so that it applies to a Generator Owner *if and when it executes an Agreement* to evaluate the reliability impact of interconnecting a third party Facility to its existing generation interconnection Facility. The intent of this modified language is to start the compliance clock when the Generator Owner executes an Agreement to perform the reliability assessment required in FAC-002-1. This step is expected to occur if a Generator Owner is compelled by a regulatory body to allow such interconnection. Assuming that a regulatory body would require a Generator Owner to evaluate such an interconnection request, the SDT expects the Generator Owner and the third party to execute some form of an Agreement. The SDT intentionally excluded a specific reference to the form of Agreement (such as a feasibility study) in deference to stakeholder suggestions to avoid comingling of commercial and reliability issues in reliability standards.

The SDT acknowledges that the scenario described in the proposed FAC-001-1 may be rare, but in the past (for instance, FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities, and the SDT thinks it is important to clarify the responsibilities related to such a request in NERC's Reliability Standards. And, while the SDT acknowledges that such regulatory action might also result in the Generator Owner being registered for other functions, such as Transmission Owner, Transmission Planner, and/or Transmission Service Provider, it decided the proposed revision provides appropriate reliability coverage until any additional registration is required and does not impact any Generator Owner that never executes an Agreement as described in the standard.

### ***FAC-003-X and FAC-003-3—Vegetation Management***

The SDT and most stakeholders agree with the Ad Hoc Group recommendation that FAC-003 be applicable to Generator Owners that own a generation interconnection Facility if that Facility contains overhead conductors. The Ad Hoc Group originally excluded such a Facility from this requirement if its length is less than two spans (generally one half mile from the generator property line). ~~After reviewing formal comments, the The SDT agreed to revise the agrees with that intended exclusion so that it applies to a Facility if its length is "one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard" to approximate line of sign from a fixed point. Other than revising this exclusion, in principle; as it discusses in the document titled "Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface," the SDT applied the same criteria to the Generator Owner as applies to the Transmission Owner in the current FERC approved version of this standard as well as one approved by stakeholders (under Project 2007-07) in February 2011. The SDT is~~

communicating with NERC staff recognizes that in many cases, generation Facilities are (1) staffed and the Project 2007-07 SDT to ensure that changes to this standard will be coordinated before submitting to NERC's Board of Trustees, but feels compelled to continue to posting both versions until the outcome of Project 2007-07 efforts is clearer overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale for exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit.

Thus, the SDT has maintained this exception language but has modified it based on stakeholder input such that it excludes Facilities shorter than one mile which have a clear line of sight from the fenced area of the generating switchyard to the point of interconnection. Specifically, sections 4.3.1 of both versions of FAC-003 (which address applicable generation Facilities) now state: "Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are..." The SDT took into consideration all comments submitted in both formal comment periods, and believes that this exemption now adequately addresses the reliability impact for a majority of the Facilities, while balancing the efforts necessary to support the standard from all entities.

#### ***PRC-004-2.1—Analysis and Mitigation of Transmission and Generation Protection System Misoperations***

After examining all standards it had previously reviewed, the SDT elected to propose a slight change to PRC-004-2.1. While the SDT rejected other opportunities to "drop" the phrase "generator interconnection Facility" into requirements because it is not typically the best way to add clarity, in the case of PRC-004-2, the SDT fears that the phrasing of R2 ("The Generator Owner shall analyze its generator Protection System Misoperations...") could lead to some confusion about whether an interconnection Facility is included. Thus, the SDT proposes adding "and generator interconnection Facility" as redlined in the draft standard. Because there is no change in applicability, and because the SDT believes that most Generator Owners already interpret the standard in this manner, we consider this to be a minor and not substantive change employed only to add clarity.

#### ***PRC-005-1a—Transmission and Generation Protection System Maintenance and Testing***

In the concurrent 45-day comment and ballot period that ended in November 2011, several commenters pointed out that the wording in R1 and R2 of PRC-005-1a requires the same explicit reference to a generator interconnection Facility that was added in PRC-004-2.1 R2. The SDT agrees and is developing revisions to PRC-005-1a. These will be posted (separate from the recirculation ballot posting) soon.

#### ***Review of Other Substantive Standards Considered by the Standard Modifications from the Ad-Hoc Report Drafting Team***



To ensure that no reliability gaps were left when the SDT shifted its strategy from the original strategy of the Ad Hoc Group, the SDT reviewed all standards for which the Ad Hoc Group had proposed changes, and again discussed whether making these standards applicable to Generator Owners or Generator Operators would increase reliability with respect to generator requirements at the transmission interface. ~~Below, the SDT provides its reasons for not proposing the substantive changes that were included in the Ad Hoc Report (that is, a change in applicability or new requirement, beyond simply adding the text “including its Generator Interconnection Facility” to an existing requirement). As Project 2010-07 continues, the SDT will work with FERC staff, NERC staff, and industry groups to determine if its list of proposed standards is supported industry-wide, and whether other standards need to be considered.~~ During the 45-day concurrent comment and ballot period that ended in November 2011, the SDT also received comments from NERC staff encouraging it to review additional standards that NERC staff had proposed to apply to Generator Owners and Generator Operators in NERC Compliance Process Directive #2011-CAG-001 Regarding Generator Transmission Leads (Directive). Similarly, stakeholder commenters encouraged the SDT to review standards cited in FERC’s Order Denying Compliance Registry Appeals of Cedar Creek Wind Energy and Milford Wind Corridor Phase I (135 FERC ¶ 61,241) (FERC Order).

~~The SDT reviewed all of these standards and requirements again and continues to find clear and technical reliability-based reasons that support not adding Generator Owner and Generator Operator requirements to the standards. The chart below indicates where else (the Ad Hoc Report, the NERC Directive, or the FERC Order) the standards addressed were discussed. While both the NERC Directive and FERC Orders address specific requirements within these standards, the SDT has found it useful to address each standard as a whole. Often, requirements within a standard, or even from standard to standard, work in concert to ensure that there are no reliability gaps, whereas a review of a requirement in isolation might give the impression that there is gap.~~

<u>Standard</u>	<u>Ad Hoc Report*</u>	<u>NERC Directive</u>	<u>FERC Order</u>
<u>EOP-003-1</u>	<u>X</u>		
<u>EOP-005-1</u>		<u>X</u>	
<u>FAC-001-0</u>		<u>X</u>	
<u>FAC-003-1 or FAC-003-2</u>	<u>X</u>	<u>X</u>	<u>X</u>
<u>FAC-014-2</u>		<u>X</u>	<u>X</u>
<u>IRO-005-2</u>	<u>X</u>		
<u>PER-001-0</u>	<u>X</u>		
<u>PER-002-0</u>	<u>X</u>	<u>X</u>	
<u>PER-003-1</u>			<u>X</u>
<u>PRC-001-1</u>		<u>X</u>	<u>X</u>
<u>TOP-001-1</u>	<u>X</u>	<u>X</u>	<u>X</u>
<u>TOP-004-2</u>	<u>X</u>	<u>X</u>	<u>X</u>
<u>TOP-006-1</u>		<u>X</u>	

TOP-008-1	X		
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\*This chart and accompanying document only address those standards in the Ad Hoc Report for which substantive changes (change in applicability or the addition of a new requirement) were proposed.

The SDT acknowledges that both NERC and FERC have stated that neither the NERC Directive nor the FERC Order is intended to prejudge the work of the SDT. The SDT also acknowledges that the discussion in the FERC Order is related to specific cases in which certain entities will actually be registered as Transmission Owners and Transmission Operators, a process that is distinct from the SDT's work, which assumes that once this project is complete, Generator Owners and Generator Operators will not be registered for any other functions based on ownership of a sole-use generator interconnection Facility. Still, because these related efforts are ongoing, the SDT thought it would be useful to directly address some of the discussion in the Directive and the Order. The rest of this document provides the SDT's technical justification for limiting the scope of its work to FAC-001, FAC-003, PRC-004, and PRC-005.

**EOP-003-1—Load Shedding Plans (addressed in the Ad Hoc Report)**

For EOP-003-1, the Ad Hoc Group originally proposed that Generator Operators be added to the requirement that requires Transmission Operators and Balancing Authorities to coordinate automatic load-shedding throughout their areas. The SDT determined that this addition was unnecessary because PRC-001 already includes the requirement that Transmission Operators coordinate their underfrequency load shedding programs with underfrequency isolation of generating units, which infersimplies that Generator Operators need to provide their underfrequency settings to their respective Transmission Operator. Further, Generator Operators typically do not have the technical expertise or access to the data necessary for the high-level coordination that this standard requires.

**EOP-005-1—System Restoration Plans (addressed in the NERC Directive)**

In its Directive, NERC staff states the following by way of rationale for applying EOP-005-1 Requirements R1, R2, R5, R6, and R7 to Generator Operators:

“If GOP has blackstart capability, then EOP-005 applies, GOP restoration plan would require coordination with TOP per the TOP Blackstart Restoration Plan. The GOP would start its blackstart resources to provide necessary real and reactive power to its generating resources per interconnecting TOP directives. In addition, if GOP has blackstart capability the interconnection TOP will have included this capability in its restoration planning for its area of responsibility. If GOP does not have blackstart capability, GOP restoration plan is dependent upon provision of real and reactive power service from interconnecting TOP, per VAR-001 and VAR-002 requiring the GOP to follow the directives of the interconnecting TOP, compliance with this standard/requirments is not required.”



Blackstart capability of a generating unit is unrelated to owning or operating transmission Facilities or a generation interconnection Facility. During a system restoration event, Generator Operators provide real and reactive power to the BES only at the direction of a Transmission Operator. The Generator Operators are not providing Transmission Operator services through their blackstart Facilities. In addition, many units with blackstart capability are not included in a TOP System Restoration Plan.

In FERC Order 693, paragraph 630, FERC approved EOP-005-1 and found the standard “adequately addresses operating personnel training and system restoration plans to ensure that transmission operators, balancing authorities and reliability coordinators are prepared to restore the Interconnection following a blackout. Accordingly, the Commission approves Reliability Standard EOP-005-1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP-005-1 through the Reliability Standards development process that identifies time frames for training and review of restoration plan requirements.”

FERC also specifically addressed system restoration training concerns and requirements in FERC Order 693 in its review and approval of Reliability Standard EOP-005-1. In that order, FERC stated that personnel outside a control room should be trained in system restoration, but also that this should be included in a system restoration Reliability Standard, as follows:

627. With regard to comments that the Commission’s concerns are being addressed in NERC’s drafting of proposed PER-005-1 Reliability Standard on operator training, we note PER-005-1 only includes Requirements on the control room personnel and not those outside of the control room. System restoration requires the participation of not only control room personnel but also those outside of the control room. These include blackstart unit operators and field switching operators in situations where SCADA capability is unavailable. As such, the Commission believes that inclusion of periodic system restoration drills and training and review of restoration plans in a system restoration Reliability Standard is the most effective way of achieving the desired goal of ensuring that all participants are trained in system restoration and that the restoration plans are up to date to deal with system changes.

Thus, FERC clearly found that the existing standard EOP-005-1 adequately addressed operating personnel training and would ensure the restoration of the BES in the event of a blackstart, and further directed that any modifications be addressed through the Reliability Standard Development Process.

Pursuant to Order 693, NERC initiated Project 2006-03, and empowered the System Restoration and Blackstart Standard Drafting Team (SRBSDT) to modify the related standards. The SRBSDT developed Reliability Standard EOP-005-2, which includes Generator Operator system restoration requirements including training, restoration plans, drills, and testing of blackstart resources. In Order 749, FERC approved EOP-005-2, which included its approval of the implementation plan for EOP-005-2. Again,

both FERC and NERC had the opportunity to identify issues with the implementation time of EOP-005-2 and declined to do so.

5. Currently effective Reliability Standard EOP-005-1 requires transmission operators, balancing authorities, and reliability coordinators to have a restoration plan, test the plan, train operating personnel in the restoration plan, and have the ability to restore the Interconnection using the plans following a blackout. In Order No. 693, the Commission directed the ERO to develop, through the Reliability Standard development process, a modification to EOP-005-1 that identifies time frames for training and review of restoration plan requirements to simulate contingencies and prepare operators for anticipated and unforeseen events . . .

Also, in FERC Order 749, both NERC and FERC identified the modifications to EOP-005 as “improvements” to the standard, not changes to close a reliability gap:

10. NERC states that the proposed Reliability Standards “represent significant revision and improvement from the current set of enforceable standards” and address the Commission’s directives in Order No. 693 related to the EOP standards. NERC explains that, among other enhancements, “[t]he proposed revisions now clearly delineate the responsibilities of the Reliability Coordinator and Transmission Operator in the restoration process and restoration planning.” NERC describes the proposed Reliability Standards as providing “specific requirements for what must be in a restoration plan, how and when it needs to be updated and approved, what needs to be provided to operators and what training is necessary for personnel involved in restoration processes.

17. . . . By enhancing the rigor of the restoration planning process, the Reliability Standards represent an improvement from the current Standards and will improve the reliability of the Bulk-Power System. . . .

In summary, the Generator Operator blackstart requirements have been already been appropriately addressed through the Reliability Standards Development Process. EOP-005-2 will become effective in 2013 as approved by both the NERC Board of Trustees and FERC. There is no existing reliability gap related to owning a generation interconnection Facility and Standard EOP-005-1.

**FAC-014-2—Establish and Communicate System Operating Limits (addressed in the NERC Directive and the FERC Order)**

FAC-014-2, R2 states “The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator’s SOL Methodology.”

In its Directive, NERC states, with respect to FAC-014-2: “In the event an RC directs the establishment of an SOL, the SOL must be established in accordance with the RC’s SOL Methodology.”

In paragraphs 68 and 84 of the FERC Order, FERC states that without compliance with FAC-014, R2, the entity in questions could “avoid establishing the system operating limit for its line or be allowed to establish an operating limit for its line that is not consistent with the requirements of the reliability coordinator’s methodology.”

The SDT does not believe that FAC-014-2 R2 should be revised to include Generator Operators. The Generator Owner is required by the FERC-approved versions of FAC-008-1 R1 and FAC-009-1 and pending FAC-008-3 R1, R2, and R6 (which has been filed for approval with FERC) to document the Facility Ratings for a Generator Owner-owned generator interconnection circuit greater than 100kV. The established Facility Rating must respect the most limiting applicable equipment rating in the circuit and must consider operating limitations and ambient conditions. The thermal or ampere rating of this circuit would equal its ampere operating limit and should be conveyed by the Generator Owner to the Generator Operator if they are not the same entity. The operating voltage limits for this circuit are established by the applicable Transmission Owner or Transmission Operator, not the Generator Owner or Generator Operator.

Therefore, we believe adding the Generator Owner to FAC-014-2 R2 would be redundant. What’s more, the SDT is concerned that entities with a limited view of the system should not be setting IROLs or SOLs. We believe this should be the responsibility of entities with a wide-area view, as shown in the standard today; otherwise, we are concerned that reliability may be jeopardized. Commenters – including one from the Transmission Owner segment – have offered this same justification.

#### ***IRO-005-2—Reliability Coordination – Current Day Operations (addressed in the Ad Hoc Report)***

The SDT chose not to adopt the revision to IRO-005-2 proposed by the Ad Hoc Group. This revision would have added a new requirement that would read, “The Generator Operator shall immediately inform the Transmission Operator of the status of the Special Protection System, including any degradation or potential failure to operate as expected for SPS relay or control equipment under its control.” The SDT initially ~~arrived at this decision~~ determined that IRO-005-2 did not require modification because of the ~~planned~~ October 2011 retirement of ~~IRO-005-2~~ the standard. In subsequent meetings, the SDT also reached the conclusion that there is no reliability gap as PRC-001-1 R2 already requires the Generator Operator to notify reliability entities of relay or equipment failures. The SDT believes that a Special Protection System is a form of protection system and therefore any degradation or potential failure to operate as expected would be required to be reported by the Generator Operator to reliability entities (Balancing Authorities, Transmission Operators, and Reliability Coordinators).

#### ***~~Personnel Performance, Training, and Qualifications (PER) Standards~~***

The SDT also chose not to propose the revisions *PER Standards (PER-001-0 and PER-002-0 were addressed in the Ad Hoc Report; PER-002-0 was addressed in the NERC Directive; and PER-003-1 was addressed in the FERC Order)*

The Ad Hoc Group had proposed changes to PER-001-0—Operating Personnel Responsibility and Authority ~~and~~ PER-002-0—Operating Personnel Training ~~that were proposed by the Ad Hoc Group.~~ For PER-001-0, the Ad Hoc Group ~~had~~ proposed adding a new R2 that would read “Each Generator Operator shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Generation Facility and Generation Interconnection Facility, and the responsibility and authority to follow the directives of reliability authorities including the Transmission Operator and Balancing Authority.” To PER-002-0, the Ad Hoc Group proposed adding the Generator Operator to R1 (“Each Transmission Operator, Generator Operator, and Balancing Authority shall be staffed with adequately trained operating personnel”) and adding a new R3 that would read: “Each Generator Operator shall implement an initial and continuing training program for all operating personnel that are responsible for operating the Generator Interconnection Facility that verifies the personnel’s ability and understanding to operate the equipment in a reliable manner.”

In its Directive, NERC does not address PER-001-0, but it states the following with respect to PER-002-0:

“The registered entity will develop an appropriate training program that contains the necessary elements for the GO/GOP operating a transmission facility to understand fully the impacts of the operation on the BPS, such as equipment involved, including protection systems, the coordination aspects with the TO/TOP to which it is connected, and the protocols for and impacts of operating facilities associated with the transmission facility. The objective of this training is to ensure that the GO/GOP is completely aware of its obligations to follow the directives of the appropriate TOP and has personnel with the skills and training to execute these obligations in the best interest of reliability.”

These proposed changes to the PER standards have little to do with responsibilities that relate specifically to a generator interconnection Facility. Issues related to the training of Generator Operators existed separately from the work of Project 2010-07, and the SDT agrees that its scope limits its efforts to standards that are directly related to generator requirements at the transmission interface. The SDT also cites past FERC Orders as proof that this issue is not within the scope of Project 2010-07. In Order 693, FERC directed NERC to "expand the applicability of the personnel training Reliability Standard, PER-002-0, to include (i) generator operators centrally-located at a generation control center with a direct impact on the reliable operation of the Bulk-Power System..." In Order 742, FERC reaffirmed this, stating that it is "not modifying the Order No. 693 directive regarding training for certain generator operator dispatch personnel, nor are we expanding a generator operator’s responsibilities—.”

Centrally-located generator operators working at a generation control center typically dispatch the output from multiple generating units. As such, they can be called upon to comply with orders from their Balancing Authority that may have a significant impact on the reliable operation of the BES. Their training would be covered by proposed ~~changechanges~~ to PER-002-0 and Order 742. Generator Operators who deal with interconnection ~~facilitiesFacilities~~ at individual generating plants, on the other hand, typically do not receive reliability-based orders specific to the interconnection Facilities and are therefore not covered by Order 742. Further, the SDT believes there is no reliability gap as TOP-001-1 R3 already requires Generator Operators ~~are, under currently approved reliability standards, required~~ to follow the directives issued by a Balancing Authority, Reliability Coordinator or of the appropriate Transmission Operator. Operators.

These training-related items are clearly important ones for the Commission, but the SDT does not think it is appropriate to fold modifications to these PER standards into the scope of its work ~~untilunless~~ it is specifically directed to do so. For now, modifications to PER-002-0 based on Order 693 directives are already included in NERC's Issue Database (P. 52-53) to be addressed by a future project. PER-001-0 is not addressed in the Issues Database, but the Project 2007-03 drafting team has proposed that the standard be retired.

#### ~~Transmission Operations (TOP) Standards~~

~~For TOP standards, the Ad Hoc Group proposed a number of new requirements that the SDT does not see as supportive of reliability. This set of standards was somewhat difficult to analyze, as the Project 2007-03 — Real-time Transmission Operations drafting team has made significant changes to TOP-001 through TOP-008, resulting in three proposed TOP standards where are currently eight (see the project's Implementation Plan). The Project 2010-07 reviewed both the FERC approved TOP standards and the fifth draft of the modified standards in Project 2007-03 to determine whether it needed to propose any additional changes to cover radial generator interconnection Facilities. In addition, the Project 2010-07 SDT contacted the Project 2010-07 to get its opinion as to whether there might be any reliability gaps related to generator interconnection facilities. No such changes will be proposed for the reasons outlined below.~~

~~The Ad Hoc Group proposed adding two new requirements to~~ The FERC Order does not address PER-001-0 or PER-002-0, but it does address PER-003-1. In paragraphs 67 and 81 of the FERC Order, FERC expresses concern that operational control over the transmission line breakers owned by the entities in question are not under the control of NERC certified operators. FERC goes on to say that "Reliability Standard PER-003-001 requires NERC certification of all operators that have responsibility for the real-time operation of the interconnected Bulk Electric System. When switching the tie-line in or out of service, operators must have the appropriate credentials and training to properly perform the switching and coordinate the switching to prevent adverse impacts such as the introduction of faults on the system."

The SDT can find no evidence that the kinds of training requirements for operating the breakers of the generator interconnection Facility cited in the FERC Order exist elsewhere for other entities that operate breakers on lines. For instance, Transmission Owners that are not also Transmission Operators are not required to undergo any sort of training. The SDT does not mean to dismiss this issue altogether, and it may be that training should be expanded to include Generator Owners, Generator Operators, Transmission Owners, end users, and possibly others, but the development of such requirements would have implications far beyond the scope and expertise of this team.

**PRC-001-1—System Protection Coordination (addressed in the NERC Directive and the FERC Order)**

The NERC Directive addresses PRC-001-1 R2, R2.2, and R4. The FERC Order addresses these requirements, along with Requirement R6.

About R2 and R4, NERC’s Directive simply states: “PRC-001-R2 requires notification and corrective action for relay or equipment failure. R4 coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.”

In paragraphs 64 and 78 of the FERC Order, FERC expresses concern that “there is a risk of an adverse impact on reliability if the protection relays or protection systems on the [entity’s] line are not coordinated with those on the transmission network facilities in its area.”

Generator Operators and the scope of protection equipment for generation interconnection Facilities are already appropriately accounted for in this standard in requirement R2 and sub-requirement R2.2. The language used in R2 that applies to the Generator Operator uses the general terms “relay or equipment failures” which would include not only generator relaying, but generator interconnection relaying in the Generator Operator’s scope as well. The Generator Operator is required to notify the Transmission Operator and Host Balancing Authority in R2.1 “if a protective relay or equipment failure reduces system reliability.” Requirement R2.2 requires the affected Transmission Operator to notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. Thus, applying R2.2 to a Generator Operator would be redundant to R2.1. If a Generator Operator had a relay or equipment failure on its Facility, including its interconnection Facility it would be required to report that to its Transmission Operator under R2.1, and the Transmission Operator is then required to notify its Reliability Coordinator and other affected Transmission Operators and Balancing Authorities under R2.2.

PRC-001-1 R4 states, “Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.” A sole-use generator interconnection Facility does not constitute a major transmission line or major interconnection with neighboring Generator Operators, Transmission Operators, and Balancing Authorities. Thus, R4 should not be revised to include

Generator Operators. In general, any coordination that might be required is covered by the fact that the Transmission Operator that is connected to a major transmission lines or interconnection has the requirement to coordinate protection on the interconnection, and there is no reliability gap.

PRC-001-1 R6 states, “Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.” It is clearly the responsibility of the Transmission Operator and/or Balancing Authority to monitor the Special Protection System, as they are the entity with a wide-area view, not the responsibility of a Generator Owner/Generator Operator with a local-area view who happens to have generator interconnection Facilities in the area. The requirement focuses on the Transmission Operator and Balancing Authority monitoring the status of each Special Protection System *in their area*; there is no “area” for the Generator Operator to monitor. For these reasons, there is no need to make this requirement applicable to Generator Operators.

***TOP-001-1—Reliability Responsibilities and Authority (addressed in the Ad Hoc Report, NERC Directive, and FERC Order)***

Both the NERC Directive and the FERC Order discuss making TOP-001-1 R1 applicable to Generator Operators. About TOP-001-1, the NERC Directive simply states: “TOP-001-1 R1 ensures personnel assigned to operate BES transmission facilities have clear and unambiguous authority to operate those facilities.” With respect to R1, paragraphs 68 and 83 of FERC’s Order focus on ensuring that “system operators have the authority to take actions to maintain Bulk-Power System facilities within operating limits.”

TOP-001-1 R1 states, “Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.” TOP-001-1 R3 appropriately requires the GOP to comply with reliability directives issued by the Transmission Operator “unless such actions would violate safety, equipment, regulatory or statutory requirements.” These requirements effectively give the Transmission Operator the necessary decision-making authority over operation of all generator Facilities up to the point of interconnection. Thus, no changes to TOP-001-1 are necessary.

Additionally, the Ad Hoc Group proposed adding two new requirements to TOP-001-1. The first was proposed as R9 and read: “The Generator Operator shall coordinate the operation of its Generator Interconnection Facility with the Transmission Operator to whom it interconnects in order to preserve Interconnection reliability...” The SDT does not agree that ~~this change is necessary.~~ TOP-001-1 needs to apply to Generator Operators in any form. TOP-002-2 R3 (proposed to be covered in the future by TOP-003-2, as outlined in Project 2007-03’s Implementation Plan) already requires the Generator Operator to coordinate its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. These entities are, in turn, required to coordinate with their respective



Transmission Operator. Additionally, TOP-002-2 R4 (proposed to be covered in the future by TOP-003-2, as outlined in Project 2007-03's Implementation Plan) requires each Balancing Authority and Transmission Operator to coordinate with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator. With these requirements, Generator Operators are already required to provide necessary operations information to Transmission Operators. To require the same thing in TOP-001-1 would be redundant.

The second new requirement proposed by the Ad Hoc Group for TOP-001-1 was R10, which was to read: "The Transmission Operator shall have decision-making authority over operation of the Generator Interconnection Operational Interface at all times in order to preserve Interconnection reliability." As cited above, TOP-002-2 R3 (proposed to be covered in the future by TOP-003-2, as outlined in Project 2007-03's Implementation Plan) already requires the Generator Operator to coordinate with its interconnecting Transmission Operator. Further, TOP-001-1 R3 (proposed to be covered in the future in the proposed IRO-001-2 R2 and R3) already requires the Generator Operator to comply with reliability directives issued by the Transmission Operator. These requirements effectively give the Transmission Operator decision-making authority over operation of all generator Facilities up to the point of interconnection. To require the same thing in TOP-001-1 would be redundant.

**TOP-004-2—Transmission Operations (addressed in the NERC Directive and the FERC Order)**

Both the NERC Directive and the FERC Order address the application of TOP-004-2 R6 to Generator Operators. In its Directive, NERC simply states: "TOP-004-2 R6 ensures formal policies and procedures are formulated to provide for coordination of activities that may impact reliability." In paragraphs 67 and 82 of the FERC Order, FERC talks about entities ensuring the development of coordination protection to coordinate switching a generator interconnection Facility in and out of service, since different entities have control over different ends of the line. FERC concludes that for the entities in question, TOP-004-2 R6 must apply.

Requirement R6 and its sub-requirements state: "R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: R6.1. Monitoring and controlling voltage levels and real and reactive power flows, R6.2. Switching transmission elements, R6.3. Planned outages of transmission elements, R6.4. Responding to IROL and SOL violations."

TOP-001-1 R3 appropriately requires the Generator Operator to comply with reliability directives issued by the Transmission Operator. These requirements give the Transmission Operator the necessary decision-making authority over operation of all generator Facilities, including interconnection Facilities, up to the point of interconnection. Further, TOP-002-2 R3 requires the



Generator Owner to coordinate its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. These entities are, in turn, required to coordinate with their respective Transmission Operators (also in TOP-002-2 R3). Each Balancing Authority and Transmission Operator is also then required to coordinate with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator (in TOP-002-2 R4). The coordination with which NERC and FERC are concerned is already addressed by these other requirements.

The Ad Hoc Group ~~also had~~ proposed a new requirement, R7, for TOP-004-2—~~Transmission Operations~~ that would read: “The Generator Operator shall operate its Generator Interconnection Facility within its applicable ratings.” The SDT does not agree that a reliability gap exists, because an operator has a fiduciary obligation to protect a Facility for which it is operationally responsible. FAC-008-1—Facility Ratings Methodology and FAC-009-1—Establish and Communicate Facility Ratings already infer that the reason for establishing a ratings methodology and communicating ~~facility ratings~~ Facility Ratings to the Reliability Coordinator, Planning Authority, Transmission Planner, and Transmission Operator is “...for use in reliable planning and operation of the Bulk Electric System.” Further, TOP-004-2 is proposed to be retired under the work of the Project 2007-03 drafting team. Its requirements will either be deleted or assigned elsewhere.

~~The Ad Hoc team proposed to add~~ **TOP-006-1—Monitoring System Conditions (addressed in the NERC Directive; the SDT believes NERC intended to refer to TOP-006-2)**

Only the NERC Directive addresses TOP-006. It states: “TOP-006-1 R3 ensures technical information is provided to the responsible personnel; R6 ensures correct and accurate data to TOP and BA.” But PRC-001-1 R1 (“Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area”) addresses the necessary Generator Operator requirements with respect to TOP-006-2 R3. The SDT believes that knowledge of the purpose and limitations of protection system schemes applied in its area (required in PRC-001-1 R1) constitutes knowledge of “the appropriate technical information concerning protective relays” (required in TOP-006-1 R3).

TOP-006-2 R6 states “Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.” FAC-001-1 R2.1.6 already requires the Transmission Owner’s facility connection requirements to address “metering and telecommunications.” Any generator Facility that interconnected with a Transmission Owner would have had to meet their Facility connection and system performance requirements for metering and telecommunications. Thus, there is no reliability gap.

**TOP-008-1—Response to Transmission Limit Violations (addressed in the Ad Hoc Report)**

Only the Ad Hoc Report addressed TOP-008-1, and it proposed a new requirement, R5, to TOP-008-1—Response to Transmission Limit Violations that would read “The Generator Operator shall disconnect the Generator Interconnection Facility when safety is jeopardized or the overload or abnormal voltage or reactive condition persists and generating equipment or the Generator Interconnection Facility is endangered. In doing so, the Generator Operator shall notify its Transmission Operator and Balancing Authority impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.” The SDT sees no reliability benefit to adding this requirement. TOP-001-1 R7 (“Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless...”) and its parts give the Generator Operator authority over its Facilities, which would include the generator interconnection Facility. If there is an outage, R7.1 requires the Generator Operator to notify and coordinate with its Transmission Operator, which is required to notify the Reliability Coordinator and other affected Transmission Operators. And as with TOP-004-2, the Project 2007-03 drafting team has proposed to ~~deletingdelete~~ all of TOP-008-1’s requirements and retiring the standard.

### Conclusion

The Project 2010-07 SDT is confident that the changes it has proposed address the reliability gap that exists with respect to the responsibilities of Generator Owners and Generator Operations that own ~~radial~~sole-use interconnection Facilities. The changes to FAC-001~~and~~, FAC-003 ~~and~~ ~~now~~-PRC-004 ~~have~~ have been supported by stakeholders during comment periods, and there has been no strong support of technical justification provided for bringing other standards into the scope of this project.

~~That said, the SDT recognizes the success of its work depends on stakeholders, NERC, and FERC agreeing that generator requirements at the transmission interface are covered under NERC Reliability Standards, both for the sake of reliability and to prevent further unwarranted registration of Generator Owners and Generator Operators as Transmission Owners and Transmission Operators. If the SDT’s work does not close the gap in the eyes of all parties, that work will have been unsuccessful, so the SDT is considering all feedback it receives with request to this project. While it is posting changes to only FAC-001, FAC-003, and PRC-004, and stands by that decision, it will continue to consider whether glossary term additions/modifications and modifications to other standards could enhance the reliability impact of this project. Based on conversations with NERC and FERC staff, and review of FERC’s Order Denying Compliance Registry Appeals of Cedar Creek Wind Energy and Milford Wind Corridor Phase I (135 FERC ¶ 61,241), the SDT is discussing whether it should consider the following requirements for further review: EOP-005-1 R1, R2, R6, R7; FAC-014-2 R2; PER-003-1 R1, R1.1, R1.2; PRC-001-1 R2, R2.2, R4, R6; PRC-004-1 R1; TOP-001 R1; TOP-004-2 R6, R6.1, R6.2, R6.3, R6.4; and TOP-006-1 R3. The SDT is actively seeking stakeholder feedback as to whether, in light of these orders, it should consider additional standards and or new or modifications to existing definitions as it proceeds with its work.~~

## Technical Justification: FAC-001-1

Project 2010-07 Generator Requirements at the Transmission Interface

In response to the June 17-July 17, 2011 formal posting of the proposed standard changes in Project 2010-07, the standard drafting team (SDT) received stakeholder comments on FAC-001-1 expressing concern about the feasibility of a Generator Owner receiving and executing an interconnection request on one of its interconnection Facilities, as well as concern about the market-related processes that would go along with such an interconnection request. In this technical justification document, the SDT seeks to further clarify its rationale for making the proposed FAC-001-1 applicable to qualifying Generator Owners.

While the SDT understands that interconnection requests for Generator Owner Facilities are still relatively rare, in the past (for instance, 134 FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities. The SDT acknowledges that FERC does not have jurisdiction over all Generator Owners, but realizes that the potential exists for a third party to request to interconnect its planned generator with an existing generator interconnection Facility (whose use at the time of the request is solely to transmit capacity, energy, and ancillary services from the existing generator).

The SDT discussed the various ways such an interconnection could occur and agrees that if the third party interconnection could be accomplished without the need for the existing Generator Owner to develop its own connection requirements and system performance requirements and determine impacts on the interconnected transmission systems, this standard need not apply to the Generator Owner. And the SDT agrees that in many cases, these connection requirements, system performance requirements, and determined impacts on the interconnected transmission systems are currently determined by entities registered as either a Transmission Owner, Transmission Planner, and/or Transmission Service Provider. However, the SDT remains convinced (based on the orders cited above) that there may be occasions where FERC or another regulatory agency compels the Generator Owner to allow a third party to interconnect its planned generator with an existing generator interconnection Facility. Where this occurs, the SDT feels it is necessary for the existing owner of that generator interconnection Facility to provide connection requirements to the third party that requests interconnection. The SDT also believes, and many comments seem to support, that performance requirements and a determination of impact to the interconnected transmission systems need to be evaluated by some entity. The question becomes which entity.

The SDT can only work within the standards development process. We cannot address other regulatory issues such as FERC-mandated open transmission access (Order 888 and subsequent) or state or provincial jurisdiction over generation or transmission assets. While we acknowledge these

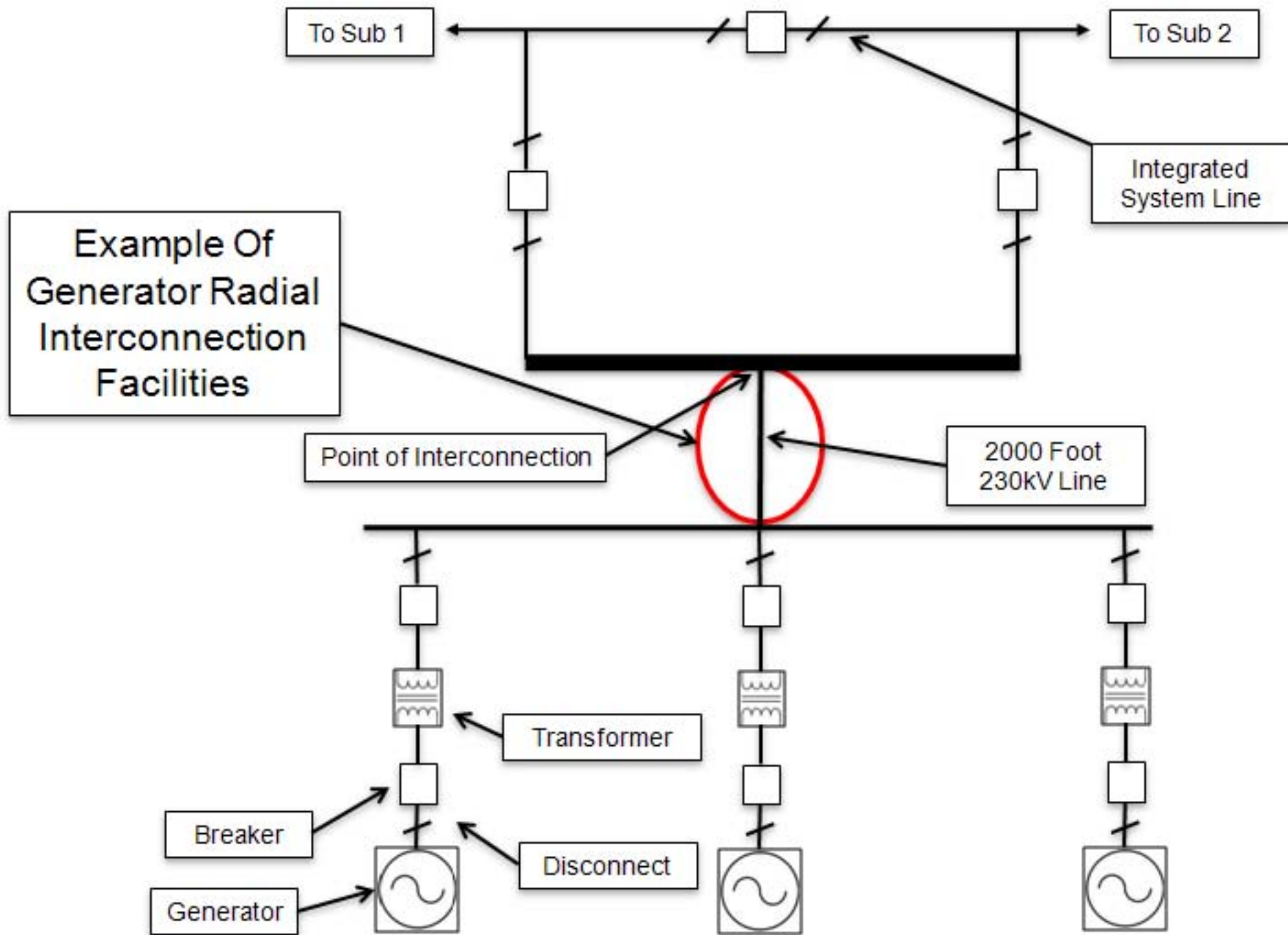
mechanisms exists and may come into play in the scenarios described in the proposed FAC-001-1, we as the SDT can only deal within the context of reliability standards. For this reason, R2 indicates that FAC-001-1 applies only when a Generator Owner has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility. The SDT's reasoning here is that if the owner of the existing generator interconnection Facility agrees, or is compelled, to allow a third party to interconnect, and can do so using existing agreements, contracts, and/or tariffs (and thereby avoid having an executed Agreement to evaluate the reliability impact of interconnecting third party Facility to the Generator Owner's existing Facility), and thus avoid having to develop its own connection requirements or perform impact studies, it will. In this example, it is likely that the existing Transmission Owner, Transmission Planner, and/or Transmission Service Provider processes and Agreements will be utilized and the purpose of FAC-001-1 will be met without applying this standard to the Generator Owner.

If, on the other hand, the owner of the existing generator interconnection Facility agrees, or is compelled, to allow a third party to interconnect, but cannot do so without having to develop its own connection requirements or perform impact studies, the SDT believes that the potential for a reliability gap exists. This might occur, for instance, if the owner of an existing generator interconnection Facility was compelled to allow interconnection and to implement open transmission access. In this example, (under FERC Order 888 and subsequent orders), the existing interconnection owner becomes a Transmission Service Provider and is required to have an Open Access Transmission Tariff (OATT). FERC's pro forma OATT requires the Transmission Service Provider to, among other things, perform system impact and feasibility studies. In order to do so, such studies must be coordinated with other Transmission Service Providers and Transmission Planners. And, to further complicate the issue, the SDT has been informed that in Texas, a Generator Owner is not allowed to own transmission.

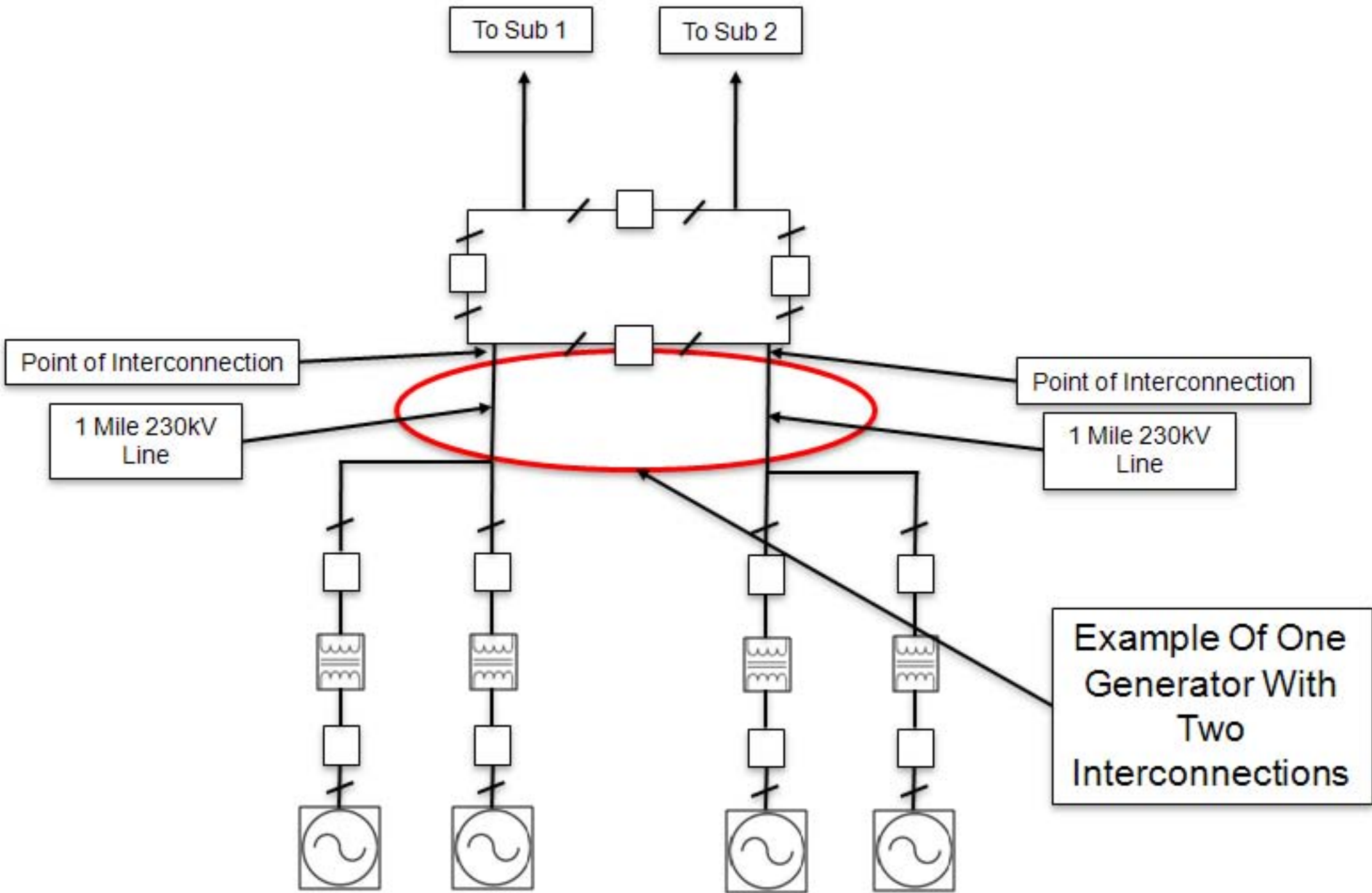
Clearly, these issues are complex and not all are within the jurisdiction of federal or provincial regulators. For these reasons, the SDT took the only approach it found workable. If, and only if, the existing owner of a generator interconnection Facility has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to its existing generation Facility would the proposed FAC-001-1 apply. The SDT believes that this is most likely to occur if the owner of an existing generator interconnection Facility is compelled to allow a third party to interconnect and adopt open transmission access. However, the SDT cannot be certain this is the only example and it therefore proposes to add this new requirement to FAC-001-1. In doing so, the SDT acknowledges that the Generator Owner may not, at the time it agrees or is compelled to allow a third party to interconnect, have the necessary expertise to conduct the required interconnect studies to meet this standard. However, the SDT believes that, upon executing such Agreement, the Generator Owner will have to acquire such expertise. How the Generator Owner chooses to do so is not for the SDT to determine. The SDT is tasked with identifying potential reliability gaps and addressing such gaps through the standards development process.

The SDT does agree with many comments asking that the Generator Owner not be required to maintain its connection requirements, and there was robust discussion among the team and observers. Some were concerned that, without an obligation to maintain, there would not be a review to ensure compliance with NERC Reliability Standards and applicable Regional Entity, subregional, Power Pool, and individual Transmission Owner planning criteria. Others were concerned that the third party requesting interconnection might not actually interconnect, but the owner of the existing generator interconnection Facility would, having executed an evaluation agreement, be forever obligated to maintain connection requirements. In the end, the SDT agreed that if the owner of the existing generator interconnection Facility adopted open access or was determined to be providing “transmission service” it was likely that its existing registration would be re-evaluated and that the issue would be more appropriately addressed at that time. The SDT has therefore agreed to remove maintenance requirements for Generator Owners from both Requirement R2 and Requirement R4 in the proposed FAC-001-1.

We hope that you have found this explanation of our rationale helpful, but if you have further suggestions for improvement or clarity, please submit them in your comments on this latest posting.







# Standards Announcement

Project 2010-07

Generator Requirements at the Transmission Interface

**Four Recirculation Ballots Window Open: December 14-23, 2011**

## [Now Available](#)

Recirculation ballot windows are open for the four standards listed below from Wednesday, December 14, 2011 through 8 p.m. Eastern on Friday, December 23, 2011.

- FAC-001-1 – Facility Connection Requirements
- Two versions of FAC-003 – Transmission Vegetation Management (FAC-003-3 and FAC-003-X). Note that FAC-003-X shows changes to FAC-003-1, while FAC-003-3 shows changes to FAC-003-2, which was developed by the Project 2007-07 standard drafting team.
- Minor modifications to PRC-004-2.1 – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

Since the initial ballot, the drafting team has considered all comments received during the formal comment period and initial ballots of the standards. Based on stakeholder comments, the SDT made minor changes to FAC-001-1, FAC-003-X, FAC-003-3, and PRC-004-2.1.

- In FAC-001-1, the SDT corrected a typo in the Applicability section 4.2.1 to change “within” to “with”; corrected a typo in the VSLs for R3 to ensure that parts 3.1.1 through 3.1.16 were referenced, rather than just 3.1.1 through 3.1.6; and changed references to “Transmission System” to “interconnected Transmission systems” to ensure consistency with the language elsewhere in the standard and in FAC-002-1.
- In FAC-003-X and FAC-003-3, the SDT added a clarifying reference to line of sight in the GO exemption in section 4.3.1. of both versions; corrected a typo in 4.3.1.2 of FAC-003-3; and changed “RE” to “Regional Entity” in 4.3.1 of FAC-003-X.

As it discusses in the document titled “[Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface](#),” the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention



approach.

To clarify the exemption, the SDT has modified the Applicability section 4.3.1 to include an explicit reference to line of sight: “Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”

With this reference, the SDT simply seeks to clarify the exception language based on the intent that has been agreed upon by the stakeholder body. In its [Consideration of Comments report](#) from the last formal comment period, which ended on July 17, 2011, the SDT explained, “We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor.” With the addition of an explicit line of sight reference here, the SDT believes it has clarified its original intent and appropriately considered all comments submitted.

Members of the ballot pool should note that the SDT is balloting both FAC-003-3 and FAC-003-X, but stakeholders should not vote as though they are choosing one or the other. The SDT plans to present FAC-003-3 alone to NERC’s Board of Trustees, but it wants to have FAC-003-X ready to submit to the Board if, for some reason, neither FAC-003-2 nor FAC-003-3 are approved by FERC. Members of the ballot body should vote on the merits of each version of FAC-003 individually. In other words, stakeholders who support adding Generator Owners to the applicability of FAC-003 should vote in the affirmative for both FAC-003-3 and FAC-003-X.

- In PRC-004-2.1, the SDT added a reference to the generator interconnection Facility to the data retention section of the standard (for consistency with the language in R2) and corrected a typo in the Version History.

Additionally, many commenters encouraged the SDT to reexamine the standards and requirements addressed in FERC’s Milford and Cedar Creek orders and NERC staff’s draft compliance directive regarding generator lead lines. The SDT reviewed all addressed standards and requirements again and continues to find clear and technical reliability-based reasons that support not adding Generator Owner and Generator Operator requirements to these standards and not requiring the Generator Owner or Generator Operator to register as a Transmission Owner or Transmission Operator. However, to address stakeholder concern, the SDT has expanded its technical justification document (posted under “Supporting Materials”) to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive.

Documents associated with this project, including clean and redline versions of each standard, implementation plans for each standard (clean only since the SDT made no changes since the last posting), the drafting team’s consideration of comments submitted during the parallel formal comment

period and initial ballot that ended on November 18, 2011, and supporting materials including two explanatory diagrams and the team's updated technical justification, have been posted on the [project page](#).

### **Instructions for Balloting in the Recirculation Ballots**

In a recirculation ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their prior votes. A ballot pool member who failed to cast a ballot during the last ballot window may cast a ballot in the recirculation ballot window. If a ballot pool member does not participate in the recirculation ballot, that member's last vote cast in the successive ballot that ended on November 18, 2011 will be carried over.

Members of the ballot pool associated with the project may log in and submit their votes in the recirculation ballots from the following page: <https://standards.nerc.net/CurrentBallots.aspx>

### **Next Steps**

If the standards achieve ballot pool approval, they will be presented to the Board of Trustees for adoption.

### **Background**

The purpose of Project 2010-07 is to ensure that all generator-owned Facilities are appropriately covered under NERC's Reliability Standards. While many Generator Owners and Generator Operators operate Facilities, commonly known as generator interconnection Facilities, that are considered by some entities to be transmission, these are most often sole-use Facilities that are not part of the integrated grid. As such, they should not be subject to the same standards applicable to Transmission Owners and Transmission Operators who own and operate Transmission Elements and Facilities that are part of the integrated grid.

As part of the BES, generators do affect the overall reliability of the BES. But registering a Generator Owner or Generator Operator as a Transmission Owner or Transmission Operator, as has been the solution in some cases in the past, may decrease reliability by diverting the Generator Owner's or Generator Operator's resources from the operation of the equipment that actually produces electricity – the generation equipment itself.

The SDT's goal is to ensure that an adequate level of reliability is maintained in the BES by clearly describing which standards need to be applied to generator interconnection Facilities that are not already applicable to Generator Owners or Generator Operators. This can be accomplished by properly applying FAC-001, FAC-003, PRC-004, and later, PRC-005, to Generator Owners as proposed in the redline standards posted for ballot.

Before reviewing the standards, the SDT encourages all stakeholders to read the technical justification resource document posted under “Supporting Materials.” This document describes, in great detail, the SDT’s rationale for its work thus far. Additional information is available on the project page at [http://www.nerc.com/filez/standards/Project2010-07\\_GOTO\\_Project.html](http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html)

### **Standards Development Process**

The [Standard Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. For more information or assistance, please contact Monica Benson at [monica.benson@nerc.net](mailto:monica.benson@nerc.net).

*For more information or assistance, please contact Monica Benson,  
Standards Process Administrator, at [monica.benson@nerc.net](mailto:monica.benson@nerc.net) or at 404-446-2560.*

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# Standards Announcement

## Project 2010-07

### Generator Requirements at the Transmission Interface

#### Recirculation Ballot Results

##### [Now Available](#)

Recirculation ballots for the four standards listed below concluded on December 23, 2011.

- FAC-001-1 – Facility Connection Requirements
- Two versions of FAC-003 – Transmission Vegetation Management (FAC-003-3 and FAC-003-X). Note that FAC-003-X shows changes to FAC-003-1, while FAC-003-3 shows changes to FAC-003-2, which was developed by the Project 2007-07 standard drafting team.
- Minor modifications to PRC-004-2.1 – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

Voting statistics for each ballot are listed in the table below, and the [Ballot Results Webpage](#) provides a link to the detailed results.

Standard	Quorum	Approval
FAC-001-1	88.48%	90.10%
FAC-003-3	87.17%	85.38%
FAC-003-X	86.91%	85.03%
PRC-004-2.1a	86.65%	96.43%

#### Next Steps

Non-binding polls of the modified VRFs and VSLs will be conducted, and the standards, associated implementation plans, and VRFs and VSLs will be presented to the NERC Board of Trustees for action. If adopted, the standards will be filed with regulatory authorities.

#### Background

The purpose of Project 2010-07 is to ensure that all generator-owned Facilities are appropriately covered under NERC's Reliability Standards. While many Generator Owners and Generator Operators operate Facilities, commonly known as generator interconnection Facilities, that are considered by

some entities to be transmission, these are most often sole-use Facilities that are not part of the integrated grid. As such, they should not be subject to the same standards applicable to Transmission Owners and Transmission Operators who own and operate Transmission Elements and Facilities that are part of the integrated grid.

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The SDT's goal is to ensure that an adequate level of reliability is maintained in the BES by clearly describing which standards need to be applied to generator interconnection Facilities that are not already applicable to Generator Owners or Generator Operators. This can be accomplished by properly applying FAC-001, FAC-003, PRC-004, and later, PRC-005, to Generator Owners as proposed in the redline standards posted for ballot.

Before reviewing the standards, the SDT encourages all stakeholders to read the technical justification resource document posted under "Supporting Materials." This document describes, in great detail, the SDT's rationale for its work thus far. Additional information is available on the project page at [http://www.nerc.com/filez/standards/Project2010-07\\_GOTO\\_Project.html](http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html)

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User Name

Password

Log in

Register

- Ballot Pools
- Current Ballots
- Ballot Results
- Registered Ballot Body
- Proxy Voters

Home Page

Ballot Results	
<b>Ballot Name:</b>	Project 2010-07_FAC-001-1 Initial Ballot_rc
<b>Ballot Period:</b>	12/14/2011 - 12/23/2011
<b>Ballot Type:</b>	recirculation
<b>Total # Votes:</b>	338
<b>Total Ballot Pool:</b>	382
<b>Quorum:</b>	<b>88.48 % The Quorum has been reached</b>
<b>Weighted Segment Vote:</b>	90.10 %
<b>Ballot Results:</b>	<b>The Standard has Passed</b>

Summary of Ballot Results									
Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain # Votes	No Vote	
			# Votes	Fraction	# Votes	Fraction			
1 - Segment 1.	95	1	68	0.919	6	0.081	10	11	
2 - Segment 2.	9	0.5	5	0.5	0	0	2	2	
3 - Segment 3.	80	1	48	0.828	10	0.172	13	9	
4 - Segment 4.	31	1	23	0.958	1	0.042	4	3	
5 - Segment 5.	94	1	66	0.93	5	0.07	11	12	
6 - Segment 6.	51	1	34	0.872	5	0.128	9	3	
7 - Segment 7.	1	0	0	0	0	0	0	1	
8 - Segment 8.	7	0.5	5	0.5	0	0	0	2	
9 - Segment 9.	5	0.2	1	0.1	1	0.1	2	1	
10 - Segment 10.	9	0.8	7	0.7	1	0.1	1	0	
<b>Totals</b>	<b>382</b>	<b>7</b>	<b>257</b>	<b>6.307</b>	<b>29</b>	<b>0.693</b>	<b>52</b>	<b>44</b>	

Individual Ballot Pool Results				
Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	<a href="#">View</a>
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Abstain	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	

1	Beaches Energy Services	Joseph S Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	<a href="#">View</a>
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	<a href="#">View</a>
1	East Kentucky Power Coop.	George S. Carruba	Abstain	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor	Affirmative	<a href="#">View</a>
1	Great River Energy	Gordon Pietsch	Affirmative	<a href="#">View</a>
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	<a href="#">View</a>
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Matthey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Brett A Koelsch	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	<a href="#">View</a>
1	Public Utility District No. 1 of Okanogan County	Dale Duncel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	



1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Affirmative	
1	Santee Cooper	Terry L Blackwell	Abstain	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	<a href="#">View</a>
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Abstain	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert Schaffeld	Negative	
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	<a href="#">View</a>
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Vermont Electric Power Company, Inc.	Kim Moulton		
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox		
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles Yeung		
3	AEP	Michael E Deloach	Affirmative	<a href="#">View</a>
3	Alabama Power Company	Richard J. Mandes	Negative	
3	Ameren Services	Mark Peters	Affirmative	
3	Anaheim Public Utilities Dept.	Kelly Nguyen	Abstain	
3	APS	Steven Norris	Abstain	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	<a href="#">View</a>
3	City of Alexandria	Michael Marcotte	Negative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Roseville	Susan E Gill-Zobitz	Abstain	
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	<a href="#">View</a>
3	Consumers Energy	Richard Blumenstock	Abstain	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	<a href="#">View</a>
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Negative	
3	Georgia Systems Operations Corporation	William N. Phinney	Abstain	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Sam Kokkinen	Affirmative	<a href="#">View</a>
3	Gulf Power Company	Paul C Caldwell	Negative	



3	Harney Electric Cooperative, Inc.	Shane Sweet	<a href="#">Abstain</a>	
3	Holland Board of Public Works	William Bush	<a href="#">Affirmative</a>	
3	Hydro One Networks, Inc.	David Kiguel	<a href="#">Affirmative</a>	
3	Imperial Irrigation District	Jesus S. Alcaraz	<a href="#">Affirmative</a>	
3	JEA	Garry Baker	<a href="#">Affirmative</a>	
3	Kansas City Power & Light Co.	Charles Locke	<a href="#">Affirmative</a>	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik	<a href="#">Abstain</a>	
3	Louisville Gas and Electric Co.	Charles A. Freibert	<a href="#">Affirmative</a>	
3	Manitoba Hydro	Greg C. Parent	<a href="#">Negative</a>	<a href="#">View</a>
3	Mississippi Power	Jeff Franklin	<a href="#">Negative</a>	
3	Municipal Electric Authority of Georgia	Steven M. Jackson		
3	Muscatine Power & Water	John S Bos	<a href="#">Affirmative</a>	<a href="#">View</a>
3	Nebraska Public Power District	Tony Eddleman	<a href="#">Affirmative</a>	
3	New York Power Authority	Marilyn Brown	<a href="#">Affirmative</a>	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	<a href="#">Affirmative</a>	
3	Northern Indiana Public Service Co.	William SeDoris	<a href="#">Negative</a>	<a href="#">View</a>
3	NRG Energy Power Marketing, Inc.	Rick Keetch		
3	Ocala Electric Utility	David Anderson	<a href="#">Affirmative</a>	
3	Orange and Rockland Utilities, Inc.	David Burke	<a href="#">Negative</a>	
3	Oregon Trail Electric Cooperative	ned ratterman	<a href="#">Affirmative</a>	
3	Orlando Utilities Commission	Ballard K Mutters	<a href="#">Affirmative</a>	
3	Owensboro Municipal Utilities	Thomas T Lyons	<a href="#">Affirmative</a>	
3	Pacific Gas and Electric Company	John H Hagen	<a href="#">Affirmative</a>	
3	PacifiCorp	Dan Zollner	<a href="#">Affirmative</a>	
3	Platte River Power Authority	Terry L Baker	<a href="#">Affirmative</a>	
3	PNM Resources	Michael Mertz		
3	Potomac Electric Power Co.	Robert Reuter	<a href="#">Abstain</a>	
3	Progress Energy Carolinas	Sam Waters	<a href="#">Affirmative</a>	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	<a href="#">Negative</a>	<a href="#">View</a>
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	<a href="#">Affirmative</a>	
3	Sacramento Municipal Utility District	James Leigh-Kendall	<a href="#">Affirmative</a>	
3	Salt River Project	John T. Underhill	<a href="#">Affirmative</a>	
3	Santee Cooper	James M Poston	<a href="#">Abstain</a>	
3	Seattle City Light	Dana Wheelock	<a href="#">Affirmative</a>	<a href="#">View</a>
3	Seminole Electric Cooperative, Inc.	James R Frauen	<a href="#">Affirmative</a>	
3	Snohomish County PUD No. 1	Mark Oens		
3	South Carolina Electric & Gas Co.	Hubert C Young	<a href="#">Affirmative</a>	
3	Tacoma Public Utilities	Travis Metcalfe	<a href="#">Affirmative</a>	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	<a href="#">Abstain</a>	
3	Tri-State G & T Association, Inc.	Janelle Marriott	<a href="#">Affirmative</a>	
3	Westar Energy	Bo Jones	<a href="#">Affirmative</a>	
3	Wisconsin Electric Power Marketing	James R Keller	<a href="#">Affirmative</a>	
3	Xcel Energy, Inc.	Michael Ibold	<a href="#">Affirmative</a>	
4	Alabama Municipal Electric Authority	Raymond Phillips	<a href="#">Affirmative</a>	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	<a href="#">Affirmative</a>	
4	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	City of Clewiston	Kevin McCarthy	<a href="#">Affirmative</a>	
4	City of Redding	Nicholas Zettel	<a href="#">Affirmative</a>	
4	City Utilities of Springfield, Missouri	John Allen	<a href="#">Affirmative</a>	<a href="#">View</a>
4	Consumers Energy	David Frank Ronk	<a href="#">Abstain</a>	
4	Cowlitz County PUD	Rick Syring	<a href="#">Affirmative</a>	
4	Detroit Edison Company	Daniel Herring	<a href="#">Affirmative</a>	
4	Flathead Electric Cooperative	Russ Schneider	<a href="#">Negative</a>	
4	Florida Municipal Power Agency	Frank Gaffney	<a href="#">Affirmative</a>	
4	Fort Pierce Utilities Authority	Thomas Richards		
4	Georgia System Operations Corporation	Guy Andrews	<a href="#">Abstain</a>	
4	Imperial Irrigation District	Diana U Torres	<a href="#">Affirmative</a>	<a href="#">View</a>
4	Indiana Municipal Power Agency	Jack Alvey	<a href="#">Affirmative</a>	
4	Integrus Energy Group, Inc.	Christopher Plante	<a href="#">Abstain</a>	
4	Madison Gas and Electric Co.	Joseph DePoorter	<a href="#">Affirmative</a>	<a href="#">View</a>
4	Modesto Irrigation District	Spencer Tacke	<a href="#">Affirmative</a>	
4	North Carolina Electric Membership Corp.	Bob Beadle	<a href="#">Affirmative</a>	
4	Northern California Power Agency	Tracy R Bibb	<a href="#">Affirmative</a>	

4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	<a href="#">View</a>
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhane	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko		
5	AES Corporation	Leo Bernier	Negative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Wind Energy Association	Natalie McIntire	Affirmative	<a href="#">View</a>
5	Arizona Public Service Co.	Edward Cambridge		
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Bayer	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	
5	City of Tallahassee	Brian Horton	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Cogentrix Energy, Inc.	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	<a href="#">View</a>
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Affirmative	<a href="#">View</a>
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	CPS Energy	Robert Stevens	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	<a href="#">View</a>
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	East Kentucky Power Coop.	Stephen Ricker	Abstain	
5	Electric Power Supply Association	John R Cashin	Affirmative	<a href="#">View</a>
5	Energy Northwest - Columbia Generating Station	James Saucedo	Affirmative	
5	Entegra Power Group, LLC	Kenneth B Parker	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Green Country Energy	Greg Froehling	Affirmative	
5	Imperial Irrigation District	Marcela Y Caballero	Affirmative	
5	Indeck Energy Services, Inc.	Rex A Roehl	Affirmative	
5	Infigen Energy US	Pamela C Zdenek	Affirmative	<a href="#">View</a>
5	Invenergy LLC	Alan Beckham	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Tom Foreman	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	

5	Manitoba Hydro	S N Fernando	Negative	<a href="#">View</a>
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego		
5	MidAmerican Energy Co.	Christopher Schneider		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern California Power Agency	Hari Modi	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	
5	Occidental Chemical	Michelle R DAntuono	Affirmative	<a href="#">View</a>
5	Oklahoma Gas and Electric Co.	Kim Morphis		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	Colin Anderson	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Fossil LLC	Mikhail Falkovich	Negative	<a href="#">View</a>
5	Public Utility District No. 1 of Lewis County	Steven Grega	Abstain	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	RES Americas Inc	Ravi Bantu	Affirmative	<a href="#">View</a>
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Siemens PTI	Edwin Cano	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	<a href="#">View</a>
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M Helyer	Affirmative	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles		
6	ACES Power Marketing	Jason L Marshall	Affirmative	<a href="#">View</a>
6	AEP Marketing	Edward P. Cox	Affirmative	<a href="#">View</a>
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	RANDY A YOUNG	Abstain	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirschak	Affirmative	
6	Colorado Springs Utilities	Lisa C Rosintoski	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	<a href="#">View</a>
6	Constellation Energy Commodities Group	Brenda Powell	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager		
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Luminant Energy	Brad Jones	Affirmative	

6	Manitoba Hydro	Daniel Prowse	Negative	<a href="#">View</a>
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Orlando Utilities Commission	Claston Augustus Sunanon	Affirmative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	<a href="#">View</a>
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	<a href="#">View</a>
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Abstain	
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein	Affirmative	
8		James A Maenner	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini		
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Volkman Consulting, Inc.	Terry Volkman	Affirmative	
9	California Energy Commission	William M Chamberlain		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Abstain	
9	New York State Department of Public Service	Thomas Dvorsky	Negative	<a href="#">View</a>
9	Public Utilities Commission of Ohio	Klaus Lambeck	Abstain	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Abstain	<a href="#">View</a>
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	<a href="#">View</a>
10	Southwest Power Pool RE	Emily Pennel	Affirmative	<a href="#">View</a>
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	<a href="#">View</a>
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	<a href="#">View</a>

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Ballot Results	
<b>Ballot Name:</b>	Project 2010-07 FAC-003-X_rc
<b>Ballot Period:</b>	12/14/2011 - 12/23/2011
<b>Ballot Type:</b>	recirculation
<b>Total # Votes:</b>	332
<b>Total Ballot Pool:</b>	382
<b>Quorum:</b>	<b>86.91 % The Quorum has been reached</b>
<b>Weighted Segment Vote:</b>	85.03 %
<b>Ballot Results:</b>	<b>The Standard has Passed</b>

Summary of Ballot Results									
Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain # Votes	No Vote	
			# Votes	Fraction	# Votes	Fraction			
1 - Segment 1.	95	1	62	0.899	7	0.101	14	12	
2 - Segment 2.	9	0.5	4	0.4	1	0.1	2	2	
3 - Segment 3.	80	1	47	0.839	9	0.161	15	9	
4 - Segment 4.	31	1	17	0.895	2	0.105	7	5	
5 - Segment 5.	94	1	57	0.877	8	0.123	14	15	
6 - Segment 6.	51	1	32	0.842	6	0.158	10	3	
7 - Segment 7.	1	0	0	0	0	0	0	1	
8 - Segment 8.	7	0.4	3	0.3	1	0.1	1	2	
9 - Segment 9.	5	0.3	3	0.3	0	0	1	1	
10 - Segment 10.	9	0.8	6	0.6	2	0.2	1	0	
<b>Totals</b>	<b>382</b>	<b>7</b>	<b>231</b>	<b>5.952</b>	<b>36</b>	<b>1.048</b>	<b>65</b>	<b>50</b>	

Individual Ballot Pool Results				
Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	<a href="#">View</a>
1	American Electric Power	Paul B. Johnson	Affirmative	<a href="#">View</a>
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Abstain	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	

1	Beaches Energy Services	Joseph S Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	<a href="#">View</a>
1	East Kentucky Power Coop.	George S. Carruba	Abstain	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	<a href="#">View</a>
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor		
1	Great River Energy	Gordon Pietsch	Affirmative	<a href="#">View</a>
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	<a href="#">View</a>
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Matthey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	<a href="#">View</a>
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PECO Energy	Ronald Schloendorn	Negative	<a href="#">View</a>
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Brett A Koelsch	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	<a href="#">View</a>
1	Public Utility District No. 1 of Okanogan County	Dale Duncel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	



1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	Santee Cooper	Terry L Blackwell	Abstain	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	<a href="#">View</a>
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Sierra Pacific Power Co.	Rich Salgo	Abstain	
1	Snohomish County PUD No. 1	Long T Duong	Abstain	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Vermont Electric Power Company, Inc.	Kim Moulton		
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox		
2	New Brunswick System Operator	Alden Briggs	Negative	<a href="#">View</a>
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles Yeung		
3	AEP	Michael E Deloach	Affirmative	<a href="#">View</a>
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	Anaheim Public Utilities Dept.	Kelly Nguyen	Abstain	
3	APS	Steven Norris	Abstain	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	<a href="#">View</a>
3	City of Alexandria	Michael Marcotte	Negative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Roseville	Susan E Gill-Zobitz	Abstain	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Negative	<a href="#">View</a>
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy	Richard Blumenstock	Abstain	<a href="#">View</a>
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	<a href="#">View</a>
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Energy Delivery	Stephan Kern	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia Systems Operations Corporation	William N. Phinney	Abstain	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Sam Kokkinen	Affirmative	<a href="#">View</a>
3	Gulf Power Company	Paul C Caldwell	Affirmative	



3	Harney Electric Cooperative, Inc.	Shane Sweet	<a href="#">Abstain</a>	
3	Holland Board of Public Works	William Bush	<a href="#">Affirmative</a>	
3	Hydro One Networks, Inc.	David Kiguel	<a href="#">Affirmative</a>	
3	Imperial Irrigation District	Jesus S. Alcaraz	<a href="#">Affirmative</a>	
3	JEA	Garry Baker	<a href="#">Affirmative</a>	
3	Kansas City Power & Light Co.	Charles Locke	<a href="#">Affirmative</a>	
3	Kissimmee Utility Authority	Gregory D Woessner	<a href="#">Negative</a>	
3	Lincoln Electric System	Jason Fortik	<a href="#">Abstain</a>	
3	Louisville Gas and Electric Co.	Charles A. Freibert	<a href="#">Affirmative</a>	
3	Manitoba Hydro	Greg C. Parent	<a href="#">Negative</a>	<a href="#">View</a>
3	Mississippi Power	Jeff Franklin	<a href="#">Affirmative</a>	
3	Municipal Electric Authority of Georgia	Steven M. Jackson		
3	Muscatine Power & Water	John S Bos	<a href="#">Affirmative</a>	
3	Nebraska Public Power District	Tony Eddleman	<a href="#">Affirmative</a>	
3	New York Power Authority	Marilyn Brown	<a href="#">Affirmative</a>	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	<a href="#">Affirmative</a>	
3	Northern Indiana Public Service Co.	William SeDoris	<a href="#">Negative</a>	<a href="#">View</a>
3	NRG Energy Power Marketing, Inc.	Rick Keetch		
3	Ocala Electric Utility	David Anderson	<a href="#">Negative</a>	
3	Orange and Rockland Utilities, Inc.	David Burke	<a href="#">Abstain</a>	
3	Oregon Trail Electric Cooperative	ned ratterman	<a href="#">Affirmative</a>	
3	Orlando Utilities Commission	Ballard K Mutters	<a href="#">Affirmative</a>	
3	Owensboro Municipal Utilities	Thomas T Lyons	<a href="#">Affirmative</a>	
3	Pacific Gas and Electric Company	John H Hagen	<a href="#">Affirmative</a>	
3	PacifiCorp	Dan Zollner	<a href="#">Affirmative</a>	
3	Platte River Power Authority	Terry L Baker	<a href="#">Affirmative</a>	
3	PNM Resources	Michael Mertz		
3	Potomac Electric Power Co.	Robert Reuter	<a href="#">Abstain</a>	
3	Progress Energy Carolinas	Sam Waters	<a href="#">Affirmative</a>	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	<a href="#">Negative</a>	<a href="#">View</a>
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	<a href="#">Affirmative</a>	
3	Sacramento Municipal Utility District	James Leigh-Kendall	<a href="#">Affirmative</a>	
3	Salt River Project	John T. Underhill	<a href="#">Affirmative</a>	
3	Santee Cooper	James M Poston	<a href="#">Abstain</a>	
3	Seattle City Light	Dana Wheelock	<a href="#">Affirmative</a>	<a href="#">View</a>
3	Seminole Electric Cooperative, Inc.	James R Frauen	<a href="#">Affirmative</a>	
3	Snohomish County PUD No. 1	Mark Oens		
3	South Carolina Electric & Gas Co.	Hubert C Young	<a href="#">Affirmative</a>	
3	Tacoma Public Utilities	Travis Metcalfe	<a href="#">Affirmative</a>	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	<a href="#">Affirmative</a>	
3	Tri-State G & T Association, Inc.	Janelle Marriott	<a href="#">Affirmative</a>	
3	Westar Energy	Bo Jones	<a href="#">Affirmative</a>	
3	Wisconsin Electric Power Marketing	James R Keller	<a href="#">Negative</a>	<a href="#">View</a>
3	Xcel Energy, Inc.	Michael Ibold	<a href="#">Affirmative</a>	
4	Alabama Municipal Electric Authority	Raymond Phillips	<a href="#">Affirmative</a>	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	<a href="#">Affirmative</a>	
4	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	City of Clewiston	Kevin McCarthy	<a href="#">Affirmative</a>	
4	City of Redding	Nicholas Zettel	<a href="#">Affirmative</a>	
4	City Utilities of Springfield, Missouri	John Allen	<a href="#">Affirmative</a>	<a href="#">View</a>
4	Consumers Energy	David Frank Ronk	<a href="#">Abstain</a>	<a href="#">View</a>
4	Cowlitz County PUD	Rick Syring	<a href="#">Affirmative</a>	
4	Detroit Edison Company	Daniel Herring	<a href="#">Affirmative</a>	
4	Flathead Electric Cooperative	Russ Schneider	<a href="#">Negative</a>	
4	Florida Municipal Power Agency	Frank Gaffney	<a href="#">Affirmative</a>	
4	Fort Pierce Utilities Authority	Thomas Richards		
4	Georgia System Operations Corporation	Guy Andrews	<a href="#">Abstain</a>	
4	Imperial Irrigation District	Diana U Torres	<a href="#">Affirmative</a>	<a href="#">View</a>
4	Indiana Municipal Power Agency	Jack Alvey		
4	Integrus Energy Group, Inc.	Christopher Plante	<a href="#">Abstain</a>	
4	Madison Gas and Electric Co.	Joseph DePoorter	<a href="#">Abstain</a>	
4	Modesto Irrigation District	Spencer Tacke		
4	North Carolina Electric Membership Corp.	Bob Beadle	<a href="#">Affirmative</a>	
4	Northern California Power Agency	Tracy R Bibb	<a href="#">Abstain</a>	

4	Ohio Edison Company	Douglas Hohlbaugh	<a href="#">Abstain</a>	
4	Old Dominion Electric Coop.	Mark Ringhausen	<a href="#">Affirmative</a>	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	<a href="#">Affirmative</a>	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	<a href="#">Abstain</a>	
4	Sacramento Municipal Utility District	Mike Ramirez	<a href="#">Affirmative</a>	
4	Seattle City Light	Hao Li	<a href="#">Affirmative</a>	<a href="#">View</a>
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	<a href="#">Affirmative</a>	
4	South Mississippi Electric Power Association	Steven McElhane	<a href="#">Affirmative</a>	
4	Tacoma Public Utilities	Keith Morisette	<a href="#">Affirmative</a>	
4	Wisconsin Energy Corp.	Anthony Jankowski	<a href="#">Negative</a>	<a href="#">View</a>
5	AEP Service Corp.	Brock Ondayko		
5	AES Corporation	Leo Bernier	<a href="#">Affirmative</a>	
5	Amerenue	Sam Dwyer	<a href="#">Negative</a>	
5	American Wind Energy Association	Natalie McIntire	<a href="#">Affirmative</a>	<a href="#">View</a>
5	Arizona Public Service Co.	Edward Cambridge		
5	Avista Corp.	Edward F. Groce	<a href="#">Affirmative</a>	
5	BC Hydro and Power Authority	Clement Ma	<a href="#">Abstain</a>	
5	Black Hills Corp	George Tatar	<a href="#">Affirmative</a>	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	<a href="#">Affirmative</a>	
5	BP Wind Energy North America Inc	Carla Bayer	<a href="#">Affirmative</a>	
5	BrightSource Energy, Inc.	Chifong Thomas	<a href="#">Abstain</a>	
5	City and County of San Francisco	Daniel Mason	<a href="#">Abstain</a>	
5	City of Austin dba Austin Energy	Jeanie Doty	<a href="#">Affirmative</a>	
5	City of Redding	Paul Cummings	<a href="#">Affirmative</a>	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	<a href="#">Affirmative</a>	
5	City of Tallahassee	Brian Horton	<a href="#">Affirmative</a>	
5	City Water, Light & Power of Springfield	Steve Rose	<a href="#">Affirmative</a>	
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy, Inc.	Mike D Hirst	<a href="#">Affirmative</a>	
5	Colorado Springs Utilities	Jennifer Eckels	<a href="#">Affirmative</a>	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	<a href="#">Abstain</a>	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	<a href="#">Affirmative</a>	<a href="#">View</a>
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex	<a href="#">Affirmative</a>	
5	CPS Energy	Robert Stevens	<a href="#">Affirmative</a>	
5	Detroit Edison Company	Christy Wicke	<a href="#">Affirmative</a>	
5	Dominion Resources, Inc.	Mike Garton	<a href="#">Affirmative</a>	
5	Duke Energy	Dale Q Goodwine	<a href="#">Affirmative</a>	<a href="#">View</a>
5	Dynegy Inc.	Dan Roethemeyer	<a href="#">Affirmative</a>	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	<a href="#">Abstain</a>	
5	East Kentucky Power Coop.	Stephen Ricker	<a href="#">Abstain</a>	
5	Electric Power Supply Association	John R Cashin	<a href="#">Affirmative</a>	
5	Energy Northwest - Columbia Generating Station	James Saucedo	<a href="#">Abstain</a>	
5	Entegra Power Group, LLC	Kenneth B Parker	<a href="#">Abstain</a>	
5	Exelon Nuclear	Michael Korchynsky	<a href="#">Negative</a>	<a href="#">View</a>
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	<a href="#">Abstain</a>	
5	Florida Municipal Power Agency	David Schumann	<a href="#">Affirmative</a>	
5	Great River Energy	Preston L Walsh	<a href="#">Affirmative</a>	
5	Green Country Energy	Greg Froehling	<a href="#">Affirmative</a>	
5	Imperial Irrigation District	Marcela Y Caballero	<a href="#">Affirmative</a>	
5	Indeck Energy Services, Inc.	Rex A Roehl	<a href="#">Affirmative</a>	
5	Infigen Energy US	Pamela C Zdenek	<a href="#">Affirmative</a>	<a href="#">View</a>
5	Invenergy LLC	Alan Beckham	<a href="#">Affirmative</a>	
5	JEA	John J Babik	<a href="#">Affirmative</a>	
5	Kissimmee Utility Authority	Mike Blough	<a href="#">Affirmative</a>	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	<a href="#">Negative</a>	<a href="#">View</a>
5	Lincoln Electric System	Dennis Florom	<a href="#">Abstain</a>	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Tom Foreman	<a href="#">Affirmative</a>	
5	Luminant Generation Company LLC	Mike Laney	<a href="#">Affirmative</a>	

5	Manitoba Hydro	S N Fernando	Negative	<a href="#">View</a>
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego		
5	MidAmerican Energy Co.	Christopher Schneider		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern California Power Agency	Hari Modi	Abstain	
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	
5	Occidental Chemical	Michelle R DAntuono	Affirmative	<a href="#">View</a>
5	Oklahoma Gas and Electric Co.	Kim Morphis		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	Colin Anderson	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Gary L Tingley		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Fossil LLC	Mikhail Falkovich	Negative	<a href="#">View</a>
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	RES Americas Inc	Ravi Bantu	Affirmative	<a href="#">View</a>
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Siemens PTI	Edwin Cano	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M Helyer	Affirmative	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	<a href="#">View</a>
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Negative	
5	Xcel Energy, Inc.	Liam Noailles		
6	ACES Power Marketing	Jason L Marshall	Affirmative	<a href="#">View</a>
6	AEP Marketing	Edward P. Cox	Affirmative	<a href="#">View</a>
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	RANDY A YOUNG	Abstain	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirschak	Negative	
6	Colorado Springs Utilities	Lisa C Rosintoski	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Abstain	
6	Constellation Energy Commodities Group	Brenda Powell	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager		
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Negative	<a href="#">View</a>
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Luminant Energy	Brad Jones	Affirmative	

6	Manitoba Hydro	Daniel Prowse	Negative	<a href="#">View</a>
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Orlando Utilities Commission	Claston Augustus Sunanon	Affirmative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	<a href="#">View</a>
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	<a href="#">View</a>
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Abstain	
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein	Affirmative	
8		James A Maenner	Abstain	
8	JDRJC Associates	Jim Cyrulewski	Negative	
8	Power Energy Group LLC	Peggy Abbadini		
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Volkman Consulting, Inc.	Terry Volkman	Affirmative	
9	California Energy Commission	William M Chamberlain		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Affirmative	
9	New York State Department of Public Service	Thomas Dvorsky	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck	Abstain	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Negative	<a href="#">View</a>
10	Southwest Power Pool RE	Emily Pennel	Affirmative	<a href="#">View</a>
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	<a href="#">View</a>
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	<a href="#">View</a>

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Ballot Results	
<b>Ballot Name:</b>	Project 2010-07 FAC-003-3 Initial Ballot_rc
<b>Ballot Period:</b>	12/14/2011 - 12/23/2011
<b>Ballot Type:</b>	recirculation
<b>Total # Votes:</b>	333
<b>Total Ballot Pool:</b>	382
<b>Quorum:</b>	<b>87.17 % The Quorum has been reached</b>
<b>Weighted Segment Vote:</b>	85.38 %
<b>Ballot Results:</b>	<b>The Standard has Passed</b>

Summary of Ballot Results								
Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain	No Vote
			# Votes	Fraction	# Votes	Fraction	# Votes	
1 - Segment 1.	95	1	63	0.875	9	0.125	12	11
2 - Segment 2.	9	0.5	5	0.5	0	0	2	2
3 - Segment 3.	80	1	49	0.86	8	0.14	14	9
4 - Segment 4.	31	1	18	0.9	2	0.1	6	5
5 - Segment 5.	94	1	59	0.881	8	0.119	12	15
6 - Segment 6.	51	1	33	0.846	6	0.154	9	3
7 - Segment 7.	1	0	0	0	0	0	0	1
8 - Segment 8.	7	0.4	3	0.3	1	0.1	1	2
9 - Segment 9.	5	0.3	3	0.3	0	0	1	1
10 - Segment 10.	9	0.9	6	0.6	3	0.3	0	0
<b>Totals</b>	<b>382</b>	<b>7.1</b>	<b>239</b>	<b>6.062</b>	<b>37</b>	<b>1.038</b>	<b>57</b>	<b>49</b>

Individual Ballot Pool Results				
Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	<a href="#">View</a>
1	American Electric Power	Paul B. Johnson	Affirmative	<a href="#">View</a>
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Abstain	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	

1	Beaches Energy Services	Joseph S Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	<a href="#">View</a>
1	East Kentucky Power Coop.	George S. Carruba	Abstain	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	<a href="#">View</a>
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor		
1	Great River Energy	Gordon Pietsch	Affirmative	<a href="#">View</a>
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Negative	<a href="#">View</a>
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Negative	<a href="#">View</a>
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	<a href="#">View</a>
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Matthey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	<a href="#">View</a>
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PECO Energy	Ronald Schloendorn	Negative	<a href="#">View</a>
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Brett A Koelsch	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	
1	Public Utility District No. 1 of Okanogan County	Dale Duncel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	



1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	Santee Cooper	Terry L Blackwell	Abstain	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	<a href="#">View</a>
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Sierra Pacific Power Co.	Rich Salgo	Abstain	
1	Snohomish County PUD No. 1	Long T Duong	Abstain	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	<a href="#">View</a>
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Vermont Electric Power Company, Inc.	Kim Moulton		
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox		
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles Yeung		
3	AEP	Michael E DeLoach	Affirmative	<a href="#">View</a>
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	Anaheim Public Utilities Dept.	Kelly Nguyen	Abstain	
3	APS	Steven Norris	Abstain	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	<a href="#">View</a>
3	City of Alexandria	Michael Marcotte	Negative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Roseville	Susan E Gill-Zobitz	Abstain	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Negative	<a href="#">View</a>
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy	Richard Blumenstock	Abstain	<a href="#">View</a>
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	<a href="#">View</a>
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia Systems Operations Corporation	William N. Phinney	Abstain	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Sam Kokkinen	Affirmative	<a href="#">View</a>
3	Gulf Power Company	Paul C Caldwell	Affirmative	



3	Harney Electric Cooperative, Inc.	Shane Sweet	<a href="#">Abstain</a>	
3	Holland Board of Public Works	William Bush	<a href="#">Affirmative</a>	
3	Hydro One Networks, Inc.	David Kiguel	<a href="#">Affirmative</a>	
3	Imperial Irrigation District	Jesus S. Alcaraz	<a href="#">Affirmative</a>	
3	JEA	Garry Baker	<a href="#">Affirmative</a>	
3	Kansas City Power & Light Co.	Charles Locke	<a href="#">Affirmative</a>	
3	Kissimmee Utility Authority	Gregory D Woessner	<a href="#">Negative</a>	
3	Lincoln Electric System	Jason Fortik	<a href="#">Abstain</a>	
3	Louisville Gas and Electric Co.	Charles A. Freibert	<a href="#">Affirmative</a>	
3	Manitoba Hydro	Greg C. Parent	<a href="#">Negative</a>	<a href="#">View</a>
3	Mississippi Power	Jeff Franklin	<a href="#">Affirmative</a>	
3	Municipal Electric Authority of Georgia	Steven M. Jackson		
3	Muscatine Power & Water	John S Bos	<a href="#">Affirmative</a>	<a href="#">View</a>
3	Nebraska Public Power District	Tony Eddleman	<a href="#">Affirmative</a>	
3	New York Power Authority	Marilyn Brown	<a href="#">Affirmative</a>	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	<a href="#">Affirmative</a>	
3	Northern Indiana Public Service Co.	William SeDoris	<a href="#">Negative</a>	<a href="#">View</a>
3	NRG Energy Power Marketing, Inc.	Rick Keetch		
3	Ocala Electric Utility	David Anderson	<a href="#">Affirmative</a>	
3	Orange and Rockland Utilities, Inc.	David Burke	<a href="#">Abstain</a>	
3	Oregon Trail Electric Cooperative	ned ratterman	<a href="#">Affirmative</a>	
3	Orlando Utilities Commission	Ballard K Mutters	<a href="#">Affirmative</a>	
3	Owensboro Municipal Utilities	Thomas T Lyons	<a href="#">Affirmative</a>	
3	Pacific Gas and Electric Company	John H Hagen	<a href="#">Affirmative</a>	
3	PacifiCorp	Dan Zollner	<a href="#">Affirmative</a>	
3	Platte River Power Authority	Terry L Baker	<a href="#">Affirmative</a>	
3	PNM Resources	Michael Mertz		
3	Potomac Electric Power Co.	Robert Reuter	<a href="#">Abstain</a>	
3	Progress Energy Carolinas	Sam Waters	<a href="#">Affirmative</a>	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	<a href="#">Negative</a>	
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	<a href="#">Affirmative</a>	
3	Sacramento Municipal Utility District	James Leigh-Kendall	<a href="#">Affirmative</a>	
3	Salt River Project	John T. Underhill	<a href="#">Affirmative</a>	
3	Santee Cooper	James M Poston	<a href="#">Abstain</a>	
3	Seattle City Light	Dana Wheelock	<a href="#">Affirmative</a>	<a href="#">View</a>
3	Seminole Electric Cooperative, Inc.	James R Frauen	<a href="#">Affirmative</a>	
3	Snohomish County PUD No. 1	Mark Oens		
3	South Carolina Electric & Gas Co.	Hubert C Young	<a href="#">Affirmative</a>	
3	Tacoma Public Utilities	Travis Metcalfe	<a href="#">Affirmative</a>	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	<a href="#">Affirmative</a>	
3	Tri-State G & T Association, Inc.	Janelle Marriott	<a href="#">Affirmative</a>	
3	Westar Energy	Bo Jones	<a href="#">Affirmative</a>	
3	Wisconsin Electric Power Marketing	James R Keller	<a href="#">Negative</a>	<a href="#">View</a>
3	Xcel Energy, Inc.	Michael Ibold	<a href="#">Affirmative</a>	
4	Alabama Municipal Electric Authority	Raymond Phillips	<a href="#">Affirmative</a>	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	<a href="#">Affirmative</a>	
4	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	City of Clewiston	Kevin McCarthy	<a href="#">Affirmative</a>	
4	City of Redding	Nicholas Zettel	<a href="#">Affirmative</a>	
4	City Utilities of Springfield, Missouri	John Allen	<a href="#">Affirmative</a>	<a href="#">View</a>
4	Consumers Energy	David Frank Ronk	<a href="#">Abstain</a>	<a href="#">View</a>
4	Cowlitz County PUD	Rick Syring	<a href="#">Affirmative</a>	
4	Detroit Edison Company	Daniel Herring	<a href="#">Affirmative</a>	
4	Flathead Electric Cooperative	Russ Schneider	<a href="#">Negative</a>	
4	Florida Municipal Power Agency	Frank Gaffney	<a href="#">Affirmative</a>	
4	Fort Pierce Utilities Authority	Thomas Richards		
4	Georgia System Operations Corporation	Guy Andrews	<a href="#">Abstain</a>	
4	Imperial Irrigation District	Diana U Torres	<a href="#">Affirmative</a>	<a href="#">View</a>
4	Indiana Municipal Power Agency	Jack Alvey		
4	Integrus Energy Group, Inc.	Christopher Plante	<a href="#">Abstain</a>	
4	Madison Gas and Electric Co.	Joseph DePoorter	<a href="#">Abstain</a>	
4	Modesto Irrigation District	Spencer Tacke		
4	North Carolina Electric Membership Corp.	Bob Beadle	<a href="#">Affirmative</a>	
4	Northern California Power Agency	Tracy R Bibb	<a href="#">Abstain</a>	

4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	<a href="#">View</a>
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	<a href="#">View</a>
5	AEP Service Corp.	Brock Ondayko		
5	AES Corporation	Leo Bernier	Affirmative	
5	Amerenue	Sam Dwyer	Negative	
5	American Wind Energy Association	Natalie McIntire	Affirmative	<a href="#">View</a>
5	Arizona Public Service Co.	Edward Cambridge		
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Bayer	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas	Abstain	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	
5	City of Tallahassee	Brian Horton	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy, Inc.	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Affirmative	<a href="#">View</a>
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	CPS Energy	Robert Stevens	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	<a href="#">View</a>
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	East Kentucky Power Coop.	Stephen Ricker	Abstain	
5	Electric Power Supply Association	John R Cashin	Affirmative	
5	Energy Northwest - Columbia Generating Station	James Saucedo	Affirmative	
5	Entegra Power Group, LLC	Kenneth B Parker	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Negative	<a href="#">View</a>
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Green Country Energy	Greg Froehling	Affirmative	
5	Imperial Irrigation District	Marcela Y Caballero	Affirmative	
5	Indeck Energy Services, Inc.	Rex A Roehl	Affirmative	
5	Infigen Energy US	Pamela C Zdenek	Affirmative	<a href="#">View</a>
5	Invenergy LLC	Alan Beckham	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Negative	<a href="#">View</a>
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Tom Foreman	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	

5	Manitoba Hydro	S N Fernando	Negative	<a href="#">View</a>
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego		
5	MidAmerican Energy Co.	Christopher Schneider		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern California Power Agency	Hari Modi	Abstain	
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	
5	Occidental Chemical	Michelle R DAntuono	Affirmative	<a href="#">View</a>
5	Oklahoma Gas and Electric Co.	Kim Morphis		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	Colin Anderson	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Gary L Tingley		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Fossil LLC	Mikhail Falkovich	Negative	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	RES Americas Inc	Ravi Bantu	Affirmative	<a href="#">View</a>
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Siemens PTI	Edwin Cano	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	<a href="#">View</a>
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M Helyer	Affirmative	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	<a href="#">View</a>
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Negative	<a href="#">View</a>
5	Xcel Energy, Inc.	Liam Noailles		
6	ACES Power Marketing	Jason L Marshall	Affirmative	<a href="#">View</a>
6	AEP Marketing	Edward P. Cox	Affirmative	<a href="#">View</a>
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	RANDY A YOUNG	Abstain	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirschak	Negative	
6	Colorado Springs Utilities	Lisa C Rosintoski	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Abstain	
6	Constellation Energy Commodities Group	Brenda Powell	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager		
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Negative	<a href="#">View</a>
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Luminant Energy	Brad Jones	Affirmative	

6	Manitoba Hydro	Daniel Prowse	Negative	<a href="#">View</a>
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Orlando Utilities Commission	Claston Augustus Sunanon	Affirmative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	<a href="#">View</a>
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Abstain	
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Edward C Stein	Affirmative	
8		James A Maenner	Abstain	
8		Roger C Zaklukiewicz	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Negative	
8	Power Energy Group LLC	Peggy Abbadini		
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Volkman Consulting, Inc.	Terry Volkman	Affirmative	
9	California Energy Commission	William M Chamberlain		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Affirmative	
9	New York State Department of Public Service	Thomas Dvorsky	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck	Abstain	
10	Florida Reliability Coordinating Council	Linda Campbell	Negative	<a href="#">View</a>
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Negative	<a href="#">View</a>
10	Southwest Power Pool RE	Emily Pennel	Affirmative	<a href="#">View</a>
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	<a href="#">View</a>
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	<a href="#">View</a>

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Ballot Results	
<b>Ballot Name:</b>	Project 2010-07 PRC-004-2.1 Initial Ballot_rc
<b>Ballot Period:</b>	12/14/2011 - 12/23/2011
<b>Ballot Type:</b>	recirculation
<b>Total # Votes:</b>	331
<b>Total Ballot Pool:</b>	382
<b>Quorum:</b>	<b>86.65 % The Quorum has been reached</b>
<b>Weighted Segment Vote:</b>	96.43 %
<b>Ballot Results:</b>	<b>The Standard has Passed</b>

Summary of Ballot Results								
Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain	No Vote
			# Votes	Fraction	# Votes	Fraction	# Votes	
1 - Segment 1.	95	1	67	0.957	3	0.043	13	12
2 - Segment 2.	9	0.5	5	0.5	0	0	2	2
3 - Segment 3.	80	1	55	0.948	3	0.052	12	10
4 - Segment 4.	31	1	22	0.957	1	0.043	4	4
5 - Segment 5.	94	1	65	0.956	3	0.044	10	16
6 - Segment 6.	51	1	37	0.925	3	0.075	8	3
7 - Segment 7.	1	0	0	0	0	0	0	1
8 - Segment 8.	7	0.5	5	0.5	0	0	0	2
9 - Segment 9.	5	0.3	3	0.3	0	0	1	1
10 - Segment 10.	9	0.9	9	0.9	0	0	0	0
<b>Totals</b>	<b>382</b>	<b>7.2</b>	<b>268</b>	<b>6.943</b>	<b>13</b>	<b>0.257</b>	<b>50</b>	<b>51</b>

Individual Ballot Pool Results				
Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	<a href="#">Affirmative</a>	<a href="#">View</a>
1	American Electric Power	Paul B. Johnson	<a href="#">Affirmative</a>	<a href="#">View</a>
1	American Transmission Company, LLC	Andrew Z Pusztai	<a href="#">Affirmative</a>	
1	Arizona Public Service Co.	Robert Smith	<a href="#">Abstain</a>	
1	Associated Electric Cooperative, Inc.	John Bussman	<a href="#">Affirmative</a>	
1	Avista Corp.	Scott J Kinney	<a href="#">Affirmative</a>	
1	Balancing Authority of Northern California	Kevin Smith	<a href="#">Affirmative</a>	
1	BC Hydro and Power Authority	Patricia Robertson	<a href="#">Abstain</a>	

1	Beaches Energy Services	Joseph S Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	<a href="#">View</a>
1	East Kentucky Power Coop.	George S. Carruba	Abstain	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Abstain	
1	Georgia Transmission Corporation	Harold Taylor		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	<a href="#">View</a>
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Matthey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	<a href="#">View</a>
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Brett A Koelsch	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Duncel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	<a href="#">View</a>



1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	Santee Cooper	Terry L Blackwell	Abstain	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	<a href="#">View</a>
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Abstain	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Abstain	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	<a href="#">View</a>
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Vermont Electric Power Company, Inc.	Kim Moulton		
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox		
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles Yeung		
3	AEP	Michael E Deloach	Affirmative	<a href="#">View</a>
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	Anaheim Public Utilities Dept.	Kelly Nguyen	Abstain	
3	APS	Steven Norris	Abstain	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	<a href="#">View</a>
3	City of Alexandria	Michael Marcotte	Negative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Roseville	Susan E Gill-Zobitz	Abstain	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Abstain	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	<a href="#">View</a>
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia Systems Operations Corporation	William N. Phinney	Abstain	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Sam Kokkinen	Affirmative	<a href="#">View</a>
3	Gulf Power Company	Paul C Caldwell	Affirmative	



3	Harney Electric Cooperative, Inc.	Shane Sweet	<a href="#">Abstain</a>	
3	Holland Board of Public Works	William Bush	<a href="#">Affirmative</a>	
3	Hydro One Networks, Inc.	David Kiguel	<a href="#">Affirmative</a>	
3	Imperial Irrigation District	Jesus S. Alcaraz	<a href="#">Affirmative</a>	
3	JEA	Garry Baker	<a href="#">Affirmative</a>	
3	Kansas City Power & Light Co.	Charles Locke	<a href="#">Affirmative</a>	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik	<a href="#">Abstain</a>	
3	Louisville Gas and Electric Co.	Charles A. Freibert	<a href="#">Affirmative</a>	
3	Manitoba Hydro	Greg C. Parent	<a href="#">Negative</a>	<a href="#">View</a>
3	Mississippi Power	Jeff Franklin	<a href="#">Affirmative</a>	
3	Municipal Electric Authority of Georgia	Steven M. Jackson		
3	Muscatine Power & Water	John S Bos	<a href="#">Affirmative</a>	
3	Nebraska Public Power District	Tony Eddleman	<a href="#">Affirmative</a>	
3	New York Power Authority	Marilyn Brown	<a href="#">Affirmative</a>	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	<a href="#">Affirmative</a>	
3	Northern Indiana Public Service Co.	William SeDoris	<a href="#">Negative</a>	<a href="#">View</a>
3	NRG Energy Power Marketing, Inc.	Rick Keetch		
3	Ocala Electric Utility	David Anderson	<a href="#">Affirmative</a>	
3	Orange and Rockland Utilities, Inc.	David Burke	<a href="#">Affirmative</a>	
3	Oregon Trail Electric Cooperative	ned ratterman	<a href="#">Affirmative</a>	
3	Orlando Utilities Commission	Ballard K Mutters	<a href="#">Affirmative</a>	
3	Owensboro Municipal Utilities	Thomas T Lyons	<a href="#">Affirmative</a>	
3	Pacific Gas and Electric Company	John H Hagen	<a href="#">Affirmative</a>	
3	PacifiCorp	Dan Zollner	<a href="#">Affirmative</a>	
3	Platte River Power Authority	Terry L Baker	<a href="#">Affirmative</a>	
3	PNM Resources	Michael Mertz		
3	Potomac Electric Power Co.	Robert Reuter	<a href="#">Abstain</a>	
3	Progress Energy Carolinas	Sam Waters	<a href="#">Affirmative</a>	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	<a href="#">Affirmative</a>	
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	<a href="#">Affirmative</a>	<a href="#">View</a>
3	Sacramento Municipal Utility District	James Leigh-Kendall	<a href="#">Affirmative</a>	
3	Salt River Project	John T. Underhill	<a href="#">Affirmative</a>	
3	Santee Cooper	James M Poston	<a href="#">Abstain</a>	
3	Seattle City Light	Dana Wheelock	<a href="#">Affirmative</a>	<a href="#">View</a>
3	Seminole Electric Cooperative, Inc.	James R Frauen	<a href="#">Affirmative</a>	
3	Snohomish County PUD No. 1	Mark Oens		
3	South Carolina Electric & Gas Co.	Hubert C Young	<a href="#">Affirmative</a>	
3	Tacoma Public Utilities	Travis Metcalfe	<a href="#">Affirmative</a>	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	<a href="#">Affirmative</a>	
3	Tri-State G & T Association, Inc.	Janelle Marriott	<a href="#">Affirmative</a>	
3	Westar Energy	Bo Jones	<a href="#">Affirmative</a>	
3	Wisconsin Electric Power Marketing	James R Keller	<a href="#">Affirmative</a>	
3	Xcel Energy, Inc.	Michael Ibold	<a href="#">Affirmative</a>	
4	Alabama Municipal Electric Authority	Raymond Phillips	<a href="#">Affirmative</a>	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	<a href="#">Affirmative</a>	
4	American Municipal Power	Kevin Koloini	<a href="#">Affirmative</a>	
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	City of Clewiston	Kevin McCarthy	<a href="#">Affirmative</a>	
4	City of Redding	Nicholas Zettel	<a href="#">Affirmative</a>	
4	City Utilities of Springfield, Missouri	John Allen	<a href="#">Affirmative</a>	
4	Consumers Energy	David Frank Ronk	<a href="#">Abstain</a>	
4	Cowlitz County PUD	Rick Syring	<a href="#">Affirmative</a>	
4	Detroit Edison Company	Daniel Herring	<a href="#">Affirmative</a>	
4	Flathead Electric Cooperative	Russ Schneider	<a href="#">Negative</a>	
4	Florida Municipal Power Agency	Frank Gaffney	<a href="#">Affirmative</a>	
4	Fort Pierce Utilities Authority	Thomas Richards		
4	Georgia System Operations Corporation	Guy Andrews	<a href="#">Abstain</a>	
4	Imperial Irrigation District	Diana U Torres	<a href="#">Affirmative</a>	<a href="#">View</a>
4	Indiana Municipal Power Agency	Jack Alvey		
4	Integrus Energy Group, Inc.	Christopher Plante	<a href="#">Abstain</a>	
4	Madison Gas and Electric Co.	Joseph DePoorter	<a href="#">Affirmative</a>	
4	Modesto Irrigation District	Spencer Tacke		
4	North Carolina Electric Membership Corp.	Bob Beadle	<a href="#">Affirmative</a>	
4	Northern California Power Agency	Tracy R Bibb	<a href="#">Affirmative</a>	

4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	<a href="#">View</a>
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhane	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	<a href="#">View</a>
5	AEP Service Corp.	Brock Ondayko		
5	AES Corporation	Leo Bernier	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Wind Energy Association	Natalie McIntire	Affirmative	<a href="#">View</a>
5	Arizona Public Service Co.	Edward Cambridge		
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Bayer	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas	Abstain	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	
5	City of Tallahassee	Brian Horton	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy, Inc.	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Affirmative	<a href="#">View</a>
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	CPS Energy	Robert Stevens	Negative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	<a href="#">View</a>
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	East Kentucky Power Coop.	Stephen Ricker	Abstain	
5	Electric Power Supply Association	John R Cashin	Affirmative	
5	Energy Northwest - Columbia Generating Station	James Saucedo	Affirmative	
5	Entegra Power Group, LLC	Kenneth B Parker	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Green Country Energy	Greg Froehling	Affirmative	
5	Imperial Irrigation District	Marcela Y Caballero	Affirmative	
5	Indeck Energy Services, Inc.	Rex A Roehl	Affirmative	
5	Infigen Energy US	Pamela C Zdenek	Affirmative	<a href="#">View</a>
5	Invenergy LLC	Alan Beckham	Affirmative	
5	JEA	John J Babik		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Tom Foreman	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	

5	Manitoba Hydro	S N Fernando	Negative	<a href="#">View</a>
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego		
5	MidAmerican Energy Co.	Christopher Schneider		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern California Power Agency	Hari Modi	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	
5	Occidental Chemical	Michelle R DAntuono	Affirmative	<a href="#">View</a>
5	Oklahoma Gas and Electric Co.	Kim Morphis		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	Colin Anderson	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Gary L Tingley		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Fossil LLC	Mikhail Falkovich	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	<a href="#">View</a>
5	RES Americas Inc	Ravi Bantu	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Siemens PTI	Edwin Cano	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M Helyer	Affirmative	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles		
6	ACES Power Marketing	Jason L Marshall	Affirmative	<a href="#">View</a>
6	AEP Marketing	Edward P. Cox	Affirmative	<a href="#">View</a>
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	RANDY A YOUNG	Abstain	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirschak	Negative	
6	Colorado Springs Utilities	Lisa C Rosintoski	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Brenda Powell	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager		
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Luminant Energy	Brad Jones	Affirmative	

6	Manitoba Hydro	Daniel Prowse	Negative	<a href="#">View</a>
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Orlando Utilities Commission	Claston Augustus Sunanon	Affirmative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	<a href="#">View</a>
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Abstain	
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein	Affirmative	
8		James A Maenner	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini		
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Volkman Consulting, Inc.	Terry Volkman	Affirmative	
9	California Energy Commission	William M Chamberlain		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Affirmative	
9	New York State Department of Public Service	Thomas Dvorsky	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck	Abstain	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	<a href="#">View</a>
10	Southwest Power Pool RE	Emily Pennel	Affirmative	<a href="#">View</a>
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	<a href="#">View</a>

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Ballot Results	
<b>Ballot Name:</b>	Project 2010-07_FAC-001-1 Initial Ballot_rc
<b>Ballot Period:</b>	12/14/2011 - 12/23/2011
<b>Ballot Type:</b>	recirculation
<b>Total # Votes:</b>	338
<b>Total Ballot Pool:</b>	382
<b>Quorum:</b>	<b>88.48 % The Quorum has been reached</b>
<b>Weighted Segment Vote:</b>	90.10 %
<b>Ballot Results:</b>	<b>The Standard has Passed</b>

Summary of Ballot Results									
Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain # Votes	No Vote	
			# Votes	Fraction	# Votes	Fraction			
1 - Segment 1.	95	1	68	0.919	6	0.081	10	11	
2 - Segment 2.	9	0.5	5	0.5	0	0	2	2	
3 - Segment 3.	80	1	48	0.828	10	0.172	13	9	
4 - Segment 4.	31	1	23	0.958	1	0.042	4	3	
5 - Segment 5.	94	1	66	0.93	5	0.07	11	12	
6 - Segment 6.	51	1	34	0.872	5	0.128	9	3	
7 - Segment 7.	1	0	0	0	0	0	0	1	
8 - Segment 8.	7	0.5	5	0.5	0	0	0	2	
9 - Segment 9.	5	0.2	1	0.1	1	0.1	2	1	
10 - Segment 10.	9	0.8	7	0.7	1	0.1	1	0	
<b>Totals</b>	<b>382</b>	<b>7</b>	<b>257</b>	<b>6.307</b>	<b>29</b>	<b>0.693</b>	<b>52</b>	<b>44</b>	

Individual Ballot Pool Results				
Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	<a href="#">View</a>
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Abstain	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	

1	Beaches Energy Services	Joseph S Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	<a href="#">View</a>
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	<a href="#">View</a>
1	East Kentucky Power Coop.	George S. Carruba	Abstain	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor	Affirmative	<a href="#">View</a>
1	Great River Energy	Gordon Pietsch	Affirmative	<a href="#">View</a>
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	<a href="#">View</a>
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Matthey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Brett A Koelsch	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	<a href="#">View</a>
1	Public Utility District No. 1 of Okanogan County	Dale Duncel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	



1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Affirmative	
1	Santee Cooper	Terry L Blackwell	Abstain	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	<a href="#">View</a>
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Abstain	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert Schaffeld	Negative	
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	<a href="#">View</a>
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Vermont Electric Power Company, Inc.	Kim Moulton		
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox		
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles Yeung		
3	AEP	Michael E Deloach	Affirmative	<a href="#">View</a>
3	Alabama Power Company	Richard J. Mandes	Negative	
3	Ameren Services	Mark Peters	Affirmative	
3	Anaheim Public Utilities Dept.	Kelly Nguyen	Abstain	
3	APS	Steven Norris	Abstain	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	<a href="#">View</a>
3	City of Alexandria	Michael Marcotte	Negative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Roseville	Susan E Gill-Zobitz	Abstain	
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	<a href="#">View</a>
3	Consumers Energy	Richard Blumenstock	Abstain	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	<a href="#">View</a>
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Negative	
3	Georgia Systems Operations Corporation	William N. Phinney	Abstain	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Sam Kokkinen	Affirmative	<a href="#">View</a>
3	Gulf Power Company	Paul C Caldwell	Negative	



3	Harney Electric Cooperative, Inc.	Shane Sweet	<a href="#">Abstain</a>	
3	Holland Board of Public Works	William Bush	<a href="#">Affirmative</a>	
3	Hydro One Networks, Inc.	David Kiguel	<a href="#">Affirmative</a>	
3	Imperial Irrigation District	Jesus S. Alcaraz	<a href="#">Affirmative</a>	
3	JEA	Garry Baker	<a href="#">Affirmative</a>	
3	Kansas City Power & Light Co.	Charles Locke	<a href="#">Affirmative</a>	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik	<a href="#">Abstain</a>	
3	Louisville Gas and Electric Co.	Charles A. Freibert	<a href="#">Affirmative</a>	
3	Manitoba Hydro	Greg C. Parent	<a href="#">Negative</a>	<a href="#">View</a>
3	Mississippi Power	Jeff Franklin	<a href="#">Negative</a>	
3	Municipal Electric Authority of Georgia	Steven M. Jackson		
3	Muscatine Power & Water	John S Bos	<a href="#">Affirmative</a>	<a href="#">View</a>
3	Nebraska Public Power District	Tony Eddleman	<a href="#">Affirmative</a>	
3	New York Power Authority	Marilyn Brown	<a href="#">Affirmative</a>	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	<a href="#">Affirmative</a>	
3	Northern Indiana Public Service Co.	William SeDoris	<a href="#">Negative</a>	<a href="#">View</a>
3	NRG Energy Power Marketing, Inc.	Rick Keetch		
3	Ocala Electric Utility	David Anderson	<a href="#">Affirmative</a>	
3	Orange and Rockland Utilities, Inc.	David Burke	<a href="#">Negative</a>	
3	Oregon Trail Electric Cooperative	ned ratterman	<a href="#">Affirmative</a>	
3	Orlando Utilities Commission	Ballard K Mutters	<a href="#">Affirmative</a>	
3	Owensboro Municipal Utilities	Thomas T Lyons	<a href="#">Affirmative</a>	
3	Pacific Gas and Electric Company	John H Hagen	<a href="#">Affirmative</a>	
3	PacifiCorp	Dan Zollner	<a href="#">Affirmative</a>	
3	Platte River Power Authority	Terry L Baker	<a href="#">Affirmative</a>	
3	PNM Resources	Michael Mertz		
3	Potomac Electric Power Co.	Robert Reuter	<a href="#">Abstain</a>	
3	Progress Energy Carolinas	Sam Waters	<a href="#">Affirmative</a>	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	<a href="#">Negative</a>	<a href="#">View</a>
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	<a href="#">Affirmative</a>	
3	Sacramento Municipal Utility District	James Leigh-Kendall	<a href="#">Affirmative</a>	
3	Salt River Project	John T. Underhill	<a href="#">Affirmative</a>	
3	Santee Cooper	James M Poston	<a href="#">Abstain</a>	
3	Seattle City Light	Dana Wheelock	<a href="#">Affirmative</a>	<a href="#">View</a>
3	Seminole Electric Cooperative, Inc.	James R Frauen	<a href="#">Affirmative</a>	
3	Snohomish County PUD No. 1	Mark Oens		
3	South Carolina Electric & Gas Co.	Hubert C Young	<a href="#">Affirmative</a>	
3	Tacoma Public Utilities	Travis Metcalfe	<a href="#">Affirmative</a>	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	<a href="#">Abstain</a>	
3	Tri-State G & T Association, Inc.	Janelle Marriott	<a href="#">Affirmative</a>	
3	Westar Energy	Bo Jones	<a href="#">Affirmative</a>	
3	Wisconsin Electric Power Marketing	James R Keller	<a href="#">Affirmative</a>	
3	Xcel Energy, Inc.	Michael Ibold	<a href="#">Affirmative</a>	
4	Alabama Municipal Electric Authority	Raymond Phillips	<a href="#">Affirmative</a>	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	<a href="#">Affirmative</a>	
4	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	City of Clewiston	Kevin McCarthy	<a href="#">Affirmative</a>	
4	City of Redding	Nicholas Zettel	<a href="#">Affirmative</a>	
4	City Utilities of Springfield, Missouri	John Allen	<a href="#">Affirmative</a>	<a href="#">View</a>
4	Consumers Energy	David Frank Ronk	<a href="#">Abstain</a>	
4	Cowlitz County PUD	Rick Syring	<a href="#">Affirmative</a>	
4	Detroit Edison Company	Daniel Herring	<a href="#">Affirmative</a>	
4	Flathead Electric Cooperative	Russ Schneider	<a href="#">Negative</a>	
4	Florida Municipal Power Agency	Frank Gaffney	<a href="#">Affirmative</a>	
4	Fort Pierce Utilities Authority	Thomas Richards		
4	Georgia System Operations Corporation	Guy Andrews	<a href="#">Abstain</a>	
4	Imperial Irrigation District	Diana U Torres	<a href="#">Affirmative</a>	<a href="#">View</a>
4	Indiana Municipal Power Agency	Jack Alvey	<a href="#">Affirmative</a>	
4	Integrus Energy Group, Inc.	Christopher Plante	<a href="#">Abstain</a>	
4	Madison Gas and Electric Co.	Joseph DePoorter	<a href="#">Affirmative</a>	<a href="#">View</a>
4	Modesto Irrigation District	Spencer Tacke	<a href="#">Affirmative</a>	
4	North Carolina Electric Membership Corp.	Bob Beadle	<a href="#">Affirmative</a>	
4	Northern California Power Agency	Tracy R Bibb	<a href="#">Affirmative</a>	

4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	<a href="#">View</a>
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhane	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko		
5	AES Corporation	Leo Bernier	Negative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Wind Energy Association	Natalie McIntire	Affirmative	<a href="#">View</a>
5	Arizona Public Service Co.	Edward Cambridge		
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Bayer	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	
5	City of Tallahassee	Brian Horton	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Cogentrix Energy, Inc.	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	<a href="#">View</a>
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Affirmative	<a href="#">View</a>
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	CPS Energy	Robert Stevens	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	<a href="#">View</a>
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	East Kentucky Power Coop.	Stephen Ricker	Abstain	
5	Electric Power Supply Association	John R Cashin	Affirmative	<a href="#">View</a>
5	Energy Northwest - Columbia Generating Station	James Saucedo	Affirmative	
5	Entegra Power Group, LLC	Kenneth B Parker	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Green Country Energy	Greg Froehling	Affirmative	
5	Imperial Irrigation District	Marcela Y Caballero	Affirmative	
5	Indeck Energy Services, Inc.	Rex A Roehl	Affirmative	
5	Infigen Energy US	Pamela C Zdenek	Affirmative	<a href="#">View</a>
5	Invenergy LLC	Alan Beckham	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Tom Foreman	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	

5	Manitoba Hydro	S N Fernando	Negative	<a href="#">View</a>
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego		
5	MidAmerican Energy Co.	Christopher Schneider		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern California Power Agency	Hari Modi	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	
5	Occidental Chemical	Michelle R DAntuono	Affirmative	<a href="#">View</a>
5	Oklahoma Gas and Electric Co.	Kim Morphis		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	Colin Anderson	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Fossil LLC	Mikhail Falkovich	Negative	<a href="#">View</a>
5	Public Utility District No. 1 of Lewis County	Steven Grega	Abstain	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	RES Americas Inc	Ravi Bantu	Affirmative	<a href="#">View</a>
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Siemens PTI	Edwin Cano	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	<a href="#">View</a>
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M Helyer	Affirmative	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles		
6	ACES Power Marketing	Jason L Marshall	Affirmative	<a href="#">View</a>
6	AEP Marketing	Edward P. Cox	Affirmative	<a href="#">View</a>
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	RANDY A YOUNG	Abstain	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirschak	Affirmative	
6	Colorado Springs Utilities	Lisa C Rosintoski	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	<a href="#">View</a>
6	Constellation Energy Commodities Group	Brenda Powell	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager		
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Luminant Energy	Brad Jones	Affirmative	

6	Manitoba Hydro	Daniel Prowse	Negative	<a href="#">View</a>
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Orlando Utilities Commission	Claston Augustus Sunanon	Affirmative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	<a href="#">View</a>
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	<a href="#">View</a>
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Abstain	
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein	Affirmative	
8		James A Maenner	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini		
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Volkman Consulting, Inc.	Terry Volkman	Affirmative	
9	California Energy Commission	William M Chamberlain		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Abstain	
9	New York State Department of Public Service	Thomas Dvorsky	Negative	<a href="#">View</a>
9	Public Utilities Commission of Ohio	Klaus Lambeck	Abstain	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Abstain	<a href="#">View</a>
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	<a href="#">View</a>
10	Southwest Power Pool RE	Emily Pennel	Affirmative	<a href="#">View</a>
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	<a href="#">View</a>
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	<a href="#">View</a>

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 Washington Office: 1120 G Street, N.W. : Suite 990 : Washington, DC 20005-3801

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Ballot Results	
<b>Ballot Name:</b>	Project 2010-07 FAC-003-X_rc
<b>Ballot Period:</b>	12/14/2011 - 12/23/2011
<b>Ballot Type:</b>	recirculation
<b>Total # Votes:</b>	332
<b>Total Ballot Pool:</b>	382
<b>Quorum:</b>	<b>86.91 % The Quorum has been reached</b>
<b>Weighted Segment Vote:</b>	85.03 %
<b>Ballot Results:</b>	<b>The Standard has Passed (Note: These ballot results have been voided.)</b>

Summary of Ballot Results									
Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain # Votes	No Vote	
			# Votes	Fraction	# Votes	Fraction			
1 - Segment 1.	95	1	62	0.899	7	0.101	14	12	
2 - Segment 2.	9	0.5	4	0.4	1	0.1	2	2	
3 - Segment 3.	80	1	47	0.839	9	0.161	15	9	
4 - Segment 4.	31	1	17	0.895	2	0.105	7	5	
5 - Segment 5.	94	1	57	0.877	8	0.123	14	15	
6 - Segment 6.	51	1	32	0.842	6	0.158	10	3	
7 - Segment 7.	1	0	0	0	0	0	0	1	
8 - Segment 8.	7	0.4	3	0.3	1	0.1	1	2	
9 - Segment 9.	5	0.3	3	0.3	0	0	1	1	
10 - Segment 10.	9	0.8	6	0.6	2	0.2	1	0	
<b>Totals</b>	<b>382</b>	<b>7</b>	<b>231</b>	<b>5.952</b>	<b>36</b>	<b>1.048</b>	<b>65</b>	<b>50</b>	

Individual Ballot Pool Results				
Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	<a href="#">View</a>
1	American Electric Power	Paul B. Johnson	Affirmative	<a href="#">View</a>
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Abstain	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	

1	Beaches Energy Services	Joseph S Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	<a href="#">View</a>
1	East Kentucky Power Coop.	George S. Carruba	Abstain	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	<a href="#">View</a>
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor		
1	Great River Energy	Gordon Pietsch	Affirmative	<a href="#">View</a>
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	<a href="#">View</a>
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Matthey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	<a href="#">View</a>
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PECO Energy	Ronald Schloendorn	Negative	<a href="#">View</a>
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Brett A Koelsch	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	<a href="#">View</a>
1	Public Utility District No. 1 of Okanogan County	Dale Duncel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	



1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	Santee Cooper	Terry L Blackwell	Abstain	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	<a href="#">View</a>
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Sierra Pacific Power Co.	Rich Salgo	Abstain	
1	Snohomish County PUD No. 1	Long T Duong	Abstain	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Vermont Electric Power Company, Inc.	Kim Moulton		
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox		
2	New Brunswick System Operator	Alden Briggs	Negative	<a href="#">View</a>
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles Yeung		
3	AEP	Michael E DeLoach	Affirmative	<a href="#">View</a>
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	Anaheim Public Utilities Dept.	Kelly Nguyen	Abstain	
3	APS	Steven Norris	Abstain	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	<a href="#">View</a>
3	City of Alexandria	Michael Marcotte	Negative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Roseville	Susan E Gill-Zobitz	Abstain	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Negative	<a href="#">View</a>
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy	Richard Blumenstock	Abstain	<a href="#">View</a>
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	<a href="#">View</a>
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Energy Delivery	Stephan Kern	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia Systems Operations Corporation	William N. Phinney	Abstain	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Sam Kokkinen	Affirmative	<a href="#">View</a>
3	Gulf Power Company	Paul C Caldwell	Affirmative	



3	Harney Electric Cooperative, Inc.	Shane Sweet	<a href="#">Abstain</a>	
3	Holland Board of Public Works	William Bush	<a href="#">Affirmative</a>	
3	Hydro One Networks, Inc.	David Kiguel	<a href="#">Affirmative</a>	
3	Imperial Irrigation District	Jesus S. Alcaraz	<a href="#">Affirmative</a>	
3	JEA	Garry Baker	<a href="#">Affirmative</a>	
3	Kansas City Power & Light Co.	Charles Locke	<a href="#">Affirmative</a>	
3	Kissimmee Utility Authority	Gregory D Woessner	<a href="#">Negative</a>	
3	Lincoln Electric System	Jason Fortik	<a href="#">Abstain</a>	
3	Louisville Gas and Electric Co.	Charles A. Freibert	<a href="#">Affirmative</a>	
3	Manitoba Hydro	Greg C. Parent	<a href="#">Negative</a>	<a href="#">View</a>
3	Mississippi Power	Jeff Franklin	<a href="#">Affirmative</a>	
3	Municipal Electric Authority of Georgia	Steven M. Jackson		
3	Muscatine Power & Water	John S Bos	<a href="#">Affirmative</a>	
3	Nebraska Public Power District	Tony Eddleman	<a href="#">Affirmative</a>	
3	New York Power Authority	Marilyn Brown	<a href="#">Affirmative</a>	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	<a href="#">Affirmative</a>	
3	Northern Indiana Public Service Co.	William SeDoris	<a href="#">Negative</a>	<a href="#">View</a>
3	NRG Energy Power Marketing, Inc.	Rick Keetch		
3	Ocala Electric Utility	David Anderson	<a href="#">Negative</a>	
3	Orange and Rockland Utilities, Inc.	David Burke	<a href="#">Abstain</a>	
3	Oregon Trail Electric Cooperative	ned ratterman	<a href="#">Affirmative</a>	
3	Orlando Utilities Commission	Ballard K Mutters	<a href="#">Affirmative</a>	
3	Owensboro Municipal Utilities	Thomas T Lyons	<a href="#">Affirmative</a>	
3	Pacific Gas and Electric Company	John H Hagen	<a href="#">Affirmative</a>	
3	PacifiCorp	Dan Zollner	<a href="#">Affirmative</a>	
3	Platte River Power Authority	Terry L Baker	<a href="#">Affirmative</a>	
3	PNM Resources	Michael Mertz		
3	Potomac Electric Power Co.	Robert Reuter	<a href="#">Abstain</a>	
3	Progress Energy Carolinas	Sam Waters	<a href="#">Affirmative</a>	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	<a href="#">Negative</a>	<a href="#">View</a>
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	<a href="#">Affirmative</a>	
3	Sacramento Municipal Utility District	James Leigh-Kendall	<a href="#">Affirmative</a>	
3	Salt River Project	John T. Underhill	<a href="#">Affirmative</a>	
3	Santee Cooper	James M Poston	<a href="#">Abstain</a>	
3	Seattle City Light	Dana Wheelock	<a href="#">Affirmative</a>	<a href="#">View</a>
3	Seminole Electric Cooperative, Inc.	James R Frauen	<a href="#">Affirmative</a>	
3	Snohomish County PUD No. 1	Mark Oens		
3	South Carolina Electric & Gas Co.	Hubert C Young	<a href="#">Affirmative</a>	
3	Tacoma Public Utilities	Travis Metcalfe	<a href="#">Affirmative</a>	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	<a href="#">Affirmative</a>	
3	Tri-State G & T Association, Inc.	Janelle Marriott	<a href="#">Affirmative</a>	
3	Westar Energy	Bo Jones	<a href="#">Affirmative</a>	
3	Wisconsin Electric Power Marketing	James R Keller	<a href="#">Negative</a>	<a href="#">View</a>
3	Xcel Energy, Inc.	Michael Ibold	<a href="#">Affirmative</a>	
4	Alabama Municipal Electric Authority	Raymond Phillips	<a href="#">Affirmative</a>	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	<a href="#">Affirmative</a>	
4	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	City of Clewiston	Kevin McCarthy	<a href="#">Affirmative</a>	
4	City of Redding	Nicholas Zettel	<a href="#">Affirmative</a>	
4	City Utilities of Springfield, Missouri	John Allen	<a href="#">Affirmative</a>	<a href="#">View</a>
4	Consumers Energy	David Frank Ronk	<a href="#">Abstain</a>	<a href="#">View</a>
4	Cowlitz County PUD	Rick Syring	<a href="#">Affirmative</a>	
4	Detroit Edison Company	Daniel Herring	<a href="#">Affirmative</a>	
4	Flathead Electric Cooperative	Russ Schneider	<a href="#">Negative</a>	
4	Florida Municipal Power Agency	Frank Gaffney	<a href="#">Affirmative</a>	
4	Fort Pierce Utilities Authority	Thomas Richards		
4	Georgia System Operations Corporation	Guy Andrews	<a href="#">Abstain</a>	
4	Imperial Irrigation District	Diana U Torres	<a href="#">Affirmative</a>	<a href="#">View</a>
4	Indiana Municipal Power Agency	Jack Alvey		
4	Integrus Energy Group, Inc.	Christopher Plante	<a href="#">Abstain</a>	
4	Madison Gas and Electric Co.	Joseph DePoorter	<a href="#">Abstain</a>	
4	Modesto Irrigation District	Spencer Tacke		
4	North Carolina Electric Membership Corp.	Bob Beadle	<a href="#">Affirmative</a>	
4	Northern California Power Agency	Tracy R Bibb	<a href="#">Abstain</a>	

4	Ohio Edison Company	Douglas Hohlbaugh	<a href="#">Abstain</a>	
4	Old Dominion Electric Coop.	Mark Ringhausen	<a href="#">Affirmative</a>	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	<a href="#">Affirmative</a>	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	<a href="#">Abstain</a>	
4	Sacramento Municipal Utility District	Mike Ramirez	<a href="#">Affirmative</a>	
4	Seattle City Light	Hao Li	<a href="#">Affirmative</a>	<a href="#">View</a>
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	<a href="#">Affirmative</a>	
4	South Mississippi Electric Power Association	Steven McElhane	<a href="#">Affirmative</a>	
4	Tacoma Public Utilities	Keith Morisette	<a href="#">Affirmative</a>	
4	Wisconsin Energy Corp.	Anthony Jankowski	<a href="#">Negative</a>	<a href="#">View</a>
5	AEP Service Corp.	Brock Ondayko		
5	AES Corporation	Leo Bernier	<a href="#">Affirmative</a>	
5	Amerenue	Sam Dwyer	<a href="#">Negative</a>	
5	American Wind Energy Association	Natalie McIntire	<a href="#">Affirmative</a>	<a href="#">View</a>
5	Arizona Public Service Co.	Edward Cambridge		
5	Avista Corp.	Edward F. Groce	<a href="#">Affirmative</a>	
5	BC Hydro and Power Authority	Clement Ma	<a href="#">Abstain</a>	
5	Black Hills Corp	George Tatar	<a href="#">Affirmative</a>	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	<a href="#">Affirmative</a>	
5	BP Wind Energy North America Inc	Carla Bayer	<a href="#">Affirmative</a>	
5	BrightSource Energy, Inc.	Chifong Thomas	<a href="#">Abstain</a>	
5	City and County of San Francisco	Daniel Mason	<a href="#">Abstain</a>	
5	City of Austin dba Austin Energy	Jeanie Doty	<a href="#">Affirmative</a>	
5	City of Redding	Paul Cummings	<a href="#">Affirmative</a>	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	<a href="#">Affirmative</a>	
5	City of Tallahassee	Brian Horton	<a href="#">Affirmative</a>	
5	City Water, Light & Power of Springfield	Steve Rose	<a href="#">Affirmative</a>	
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy, Inc.	Mike D Hirst	<a href="#">Affirmative</a>	
5	Colorado Springs Utilities	Jennifer Eckels	<a href="#">Affirmative</a>	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	<a href="#">Abstain</a>	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	<a href="#">Affirmative</a>	<a href="#">View</a>
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex	<a href="#">Affirmative</a>	
5	CPS Energy	Robert Stevens	<a href="#">Affirmative</a>	
5	Detroit Edison Company	Christy Wicke	<a href="#">Affirmative</a>	
5	Dominion Resources, Inc.	Mike Garton	<a href="#">Affirmative</a>	
5	Duke Energy	Dale Q Goodwine	<a href="#">Affirmative</a>	<a href="#">View</a>
5	Dynegy Inc.	Dan Roethemeyer	<a href="#">Affirmative</a>	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	<a href="#">Abstain</a>	
5	East Kentucky Power Coop.	Stephen Ricker	<a href="#">Abstain</a>	
5	Electric Power Supply Association	John R Cashin	<a href="#">Affirmative</a>	
5	Energy Northwest - Columbia Generating Station	James Saucedo	<a href="#">Abstain</a>	
5	Entegra Power Group, LLC	Kenneth B Parker	<a href="#">Abstain</a>	
5	Exelon Nuclear	Michael Korchynsky	<a href="#">Negative</a>	<a href="#">View</a>
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	<a href="#">Abstain</a>	
5	Florida Municipal Power Agency	David Schumann	<a href="#">Affirmative</a>	
5	Great River Energy	Preston L Walsh	<a href="#">Affirmative</a>	
5	Green Country Energy	Greg Froehling	<a href="#">Affirmative</a>	
5	Imperial Irrigation District	Marcela Y Caballero	<a href="#">Affirmative</a>	
5	Indeck Energy Services, Inc.	Rex A Roehl	<a href="#">Affirmative</a>	
5	Infigen Energy US	Pamela C Zdenek	<a href="#">Affirmative</a>	<a href="#">View</a>
5	Invenergy LLC	Alan Beckham	<a href="#">Affirmative</a>	
5	JEA	John J Babik	<a href="#">Affirmative</a>	
5	Kissimmee Utility Authority	Mike Blough	<a href="#">Affirmative</a>	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	<a href="#">Negative</a>	<a href="#">View</a>
5	Lincoln Electric System	Dennis Florom	<a href="#">Abstain</a>	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Tom Foreman	<a href="#">Affirmative</a>	
5	Luminant Generation Company LLC	Mike Laney	<a href="#">Affirmative</a>	

5	Manitoba Hydro	S N Fernando	Negative	<a href="#">View</a>
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego		
5	MidAmerican Energy Co.	Christopher Schneider		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern California Power Agency	Hari Modi	Abstain	
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	
5	Occidental Chemical	Michelle R DAntuono	Affirmative	<a href="#">View</a>
5	Oklahoma Gas and Electric Co.	Kim Morphis		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	Colin Anderson	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Gary L Tingley		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Fossil LLC	Mikhail Falkovich	Negative	<a href="#">View</a>
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	RES Americas Inc	Ravi Bantu	Affirmative	<a href="#">View</a>
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Siemens PTI	Edwin Cano	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M Helyer	Affirmative	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	<a href="#">View</a>
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Negative	
5	Xcel Energy, Inc.	Liam Noailles		
6	ACES Power Marketing	Jason L Marshall	Affirmative	<a href="#">View</a>
6	AEP Marketing	Edward P. Cox	Affirmative	<a href="#">View</a>
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	RANDY A YOUNG	Abstain	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirschak	Negative	
6	Colorado Springs Utilities	Lisa C Rosintoski	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Abstain	
6	Constellation Energy Commodities Group	Brenda Powell	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager		
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Negative	<a href="#">View</a>
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Luminant Energy	Brad Jones	Affirmative	

6	Manitoba Hydro	Daniel Prowse	Negative	<a href="#">View</a>
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Orlando Utilities Commission	Claston Augustus Sunanon	Affirmative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	<a href="#">View</a>
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	<a href="#">View</a>
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Abstain	
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein	Affirmative	
8		James A Maenner	Abstain	
8	JDRJC Associates	Jim Cyrulewski	Negative	
8	Power Energy Group LLC	Peggy Abbadini		
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Volkman Consulting, Inc.	Terry Volkman	Affirmative	
9	California Energy Commission	William M Chamberlain		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Affirmative	
9	New York State Department of Public Service	Thomas Dvorsky	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck	Abstain	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Negative	<a href="#">View</a>
10	Southwest Power Pool RE	Emily Pennel	Affirmative	<a href="#">View</a>
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	<a href="#">View</a>
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	<a href="#">View</a>

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Ballot Results	
<b>Ballot Name:</b>	Project 2010-07 FAC-003-3 Initial Ballot_rc
<b>Ballot Period:</b>	12/14/2011 - 12/23/2011
<b>Ballot Type:</b>	recirculation
<b>Total # Votes:</b>	333
<b>Total Ballot Pool:</b>	382
<b>Quorum:</b>	<b>87.17 % The Quorum has been reached</b>
<b>Weighted Segment Vote:</b>	85.38 %
<b>Ballot Results:</b>	<b>The Standard has Passed (Note: These ballot results have been voided.)</b>

Summary of Ballot Results								
Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain	No Vote
			# Votes	Fraction	# Votes	Fraction	# Votes	
1 - Segment 1.	95	1	63	0.875	9	0.125	12	11
2 - Segment 2.	9	0.5	5	0.5	0	0	2	2
3 - Segment 3.	80	1	49	0.86	8	0.14	14	9
4 - Segment 4.	31	1	18	0.9	2	0.1	6	5
5 - Segment 5.	94	1	59	0.881	8	0.119	12	15
6 - Segment 6.	51	1	33	0.846	6	0.154	9	3
7 - Segment 7.	1	0	0	0	0	0	0	1
8 - Segment 8.	7	0.4	3	0.3	1	0.1	1	2
9 - Segment 9.	5	0.3	3	0.3	0	0	1	1
10 - Segment 10.	9	0.9	6	0.6	3	0.3	0	0
<b>Totals</b>	<b>382</b>	<b>7.1</b>	<b>239</b>	<b>6.062</b>	<b>37</b>	<b>1.038</b>	<b>57</b>	<b>49</b>

Individual Ballot Pool Results				
Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	<a href="#">View</a>
1	American Electric Power	Paul B. Johnson	Affirmative	<a href="#">View</a>
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Abstain	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	

1	Beaches Energy Services	Joseph S Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	<a href="#">View</a>
1	East Kentucky Power Coop.	George S. Carruba	Abstain	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	<a href="#">View</a>
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor		
1	Great River Energy	Gordon Pietsch	Affirmative	<a href="#">View</a>
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Negative	<a href="#">View</a>
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Negative	<a href="#">View</a>
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	<a href="#">View</a>
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Matthey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	<a href="#">View</a>
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PECO Energy	Ronald Schloendorn	Negative	<a href="#">View</a>
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Brett A Koelsch	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	
1	Public Utility District No. 1 of Okanogan County	Dale Duncel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	



1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	Santee Cooper	Terry L Blackwell	Abstain	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	<a href="#">View</a>
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Sierra Pacific Power Co.	Rich Salgo	Abstain	
1	Snohomish County PUD No. 1	Long T Duong	Abstain	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	<a href="#">View</a>
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Vermont Electric Power Company, Inc.	Kim Moulton		
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox		
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles Yeung		
3	AEP	Michael E DeLoach	Affirmative	<a href="#">View</a>
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	Anaheim Public Utilities Dept.	Kelly Nguyen	Abstain	
3	APS	Steven Norris	Abstain	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	<a href="#">View</a>
3	City of Alexandria	Michael Marcotte	Negative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Roseville	Susan E Gill-Zobitz	Abstain	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Negative	<a href="#">View</a>
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy	Richard Blumenstock	Abstain	<a href="#">View</a>
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	<a href="#">View</a>
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia Systems Operations Corporation	William N. Phinney	Abstain	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Sam Kokkinen	Affirmative	<a href="#">View</a>
3	Gulf Power Company	Paul C Caldwell	Affirmative	



3	Harney Electric Cooperative, Inc.	Shane Sweet	<a href="#">Abstain</a>	
3	Holland Board of Public Works	William Bush	<a href="#">Affirmative</a>	
3	Hydro One Networks, Inc.	David Kiguel	<a href="#">Affirmative</a>	
3	Imperial Irrigation District	Jesus S. Alcaraz	<a href="#">Affirmative</a>	
3	JEA	Garry Baker	<a href="#">Affirmative</a>	
3	Kansas City Power & Light Co.	Charles Locke	<a href="#">Affirmative</a>	
3	Kissimmee Utility Authority	Gregory D Woessner	<a href="#">Negative</a>	
3	Lincoln Electric System	Jason Fortik	<a href="#">Abstain</a>	
3	Louisville Gas and Electric Co.	Charles A. Freibert	<a href="#">Affirmative</a>	
3	Manitoba Hydro	Greg C. Parent	<a href="#">Negative</a>	<a href="#">View</a>
3	Mississippi Power	Jeff Franklin	<a href="#">Affirmative</a>	
3	Municipal Electric Authority of Georgia	Steven M. Jackson		
3	Muscatine Power & Water	John S Bos	<a href="#">Affirmative</a>	<a href="#">View</a>
3	Nebraska Public Power District	Tony Eddleman	<a href="#">Affirmative</a>	
3	New York Power Authority	Marilyn Brown	<a href="#">Affirmative</a>	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	<a href="#">Affirmative</a>	
3	Northern Indiana Public Service Co.	William SeDoris	<a href="#">Negative</a>	<a href="#">View</a>
3	NRG Energy Power Marketing, Inc.	Rick Keetch		
3	Ocala Electric Utility	David Anderson	<a href="#">Affirmative</a>	
3	Orange and Rockland Utilities, Inc.	David Burke	<a href="#">Abstain</a>	
3	Oregon Trail Electric Cooperative	ned ratterman	<a href="#">Affirmative</a>	
3	Orlando Utilities Commission	Ballard K Mutters	<a href="#">Affirmative</a>	
3	Owensboro Municipal Utilities	Thomas T Lyons	<a href="#">Affirmative</a>	
3	Pacific Gas and Electric Company	John H Hagen	<a href="#">Affirmative</a>	
3	PacifiCorp	Dan Zollner	<a href="#">Affirmative</a>	
3	Platte River Power Authority	Terry L Baker	<a href="#">Affirmative</a>	
3	PNM Resources	Michael Mertz		
3	Potomac Electric Power Co.	Robert Reuter	<a href="#">Abstain</a>	
3	Progress Energy Carolinas	Sam Waters	<a href="#">Affirmative</a>	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	<a href="#">Negative</a>	
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	<a href="#">Affirmative</a>	
3	Sacramento Municipal Utility District	James Leigh-Kendall	<a href="#">Affirmative</a>	
3	Salt River Project	John T. Underhill	<a href="#">Affirmative</a>	
3	Santee Cooper	James M Poston	<a href="#">Abstain</a>	
3	Seattle City Light	Dana Wheelock	<a href="#">Affirmative</a>	<a href="#">View</a>
3	Seminole Electric Cooperative, Inc.	James R Frauen	<a href="#">Affirmative</a>	
3	Snohomish County PUD No. 1	Mark Oens		
3	South Carolina Electric & Gas Co.	Hubert C Young	<a href="#">Affirmative</a>	
3	Tacoma Public Utilities	Travis Metcalfe	<a href="#">Affirmative</a>	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	<a href="#">Affirmative</a>	
3	Tri-State G & T Association, Inc.	Janelle Marriott	<a href="#">Affirmative</a>	
3	Westar Energy	Bo Jones	<a href="#">Affirmative</a>	
3	Wisconsin Electric Power Marketing	James R Keller	<a href="#">Negative</a>	<a href="#">View</a>
3	Xcel Energy, Inc.	Michael Ibold	<a href="#">Affirmative</a>	
4	Alabama Municipal Electric Authority	Raymond Phillips	<a href="#">Affirmative</a>	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	<a href="#">Affirmative</a>	
4	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	City of Clewiston	Kevin McCarthy	<a href="#">Affirmative</a>	
4	City of Redding	Nicholas Zettel	<a href="#">Affirmative</a>	
4	City Utilities of Springfield, Missouri	John Allen	<a href="#">Affirmative</a>	<a href="#">View</a>
4	Consumers Energy	David Frank Ronk	<a href="#">Abstain</a>	<a href="#">View</a>
4	Cowlitz County PUD	Rick Syring	<a href="#">Affirmative</a>	
4	Detroit Edison Company	Daniel Herring	<a href="#">Affirmative</a>	
4	Flathead Electric Cooperative	Russ Schneider	<a href="#">Negative</a>	
4	Florida Municipal Power Agency	Frank Gaffney	<a href="#">Affirmative</a>	
4	Fort Pierce Utilities Authority	Thomas Richards		
4	Georgia System Operations Corporation	Guy Andrews	<a href="#">Abstain</a>	
4	Imperial Irrigation District	Diana U Torres	<a href="#">Affirmative</a>	<a href="#">View</a>
4	Indiana Municipal Power Agency	Jack Alvey		
4	Integrus Energy Group, Inc.	Christopher Plante	<a href="#">Abstain</a>	
4	Madison Gas and Electric Co.	Joseph DePoorter	<a href="#">Abstain</a>	
4	Modesto Irrigation District	Spencer Tacke		
4	North Carolina Electric Membership Corp.	Bob Beadle	<a href="#">Affirmative</a>	
4	Northern California Power Agency	Tracy R Bibb	<a href="#">Abstain</a>	

4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	<a href="#">View</a>
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	<a href="#">View</a>
5	AEP Service Corp.	Brock Ondayko		
5	AES Corporation	Leo Bernier	Affirmative	
5	Amerenue	Sam Dwyer	Negative	
5	American Wind Energy Association	Natalie McIntire	Affirmative	<a href="#">View</a>
5	Arizona Public Service Co.	Edward Cambridge		
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Bayer	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas	Abstain	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	
5	City of Tallahassee	Brian Horton	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy, Inc.	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Affirmative	<a href="#">View</a>
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	CPS Energy	Robert Stevens	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	<a href="#">View</a>
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	East Kentucky Power Coop.	Stephen Ricker	Abstain	
5	Electric Power Supply Association	John R Cashin	Affirmative	
5	Energy Northwest - Columbia Generating Station	James Saucedo	Affirmative	
5	Entegra Power Group, LLC	Kenneth B Parker	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Negative	<a href="#">View</a>
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Green Country Energy	Greg Froehling	Affirmative	
5	Imperial Irrigation District	Marcela Y Caballero	Affirmative	
5	Indeck Energy Services, Inc.	Rex A Roehl	Affirmative	
5	Infigen Energy US	Pamela C Zdenek	Affirmative	<a href="#">View</a>
5	Invenergy LLC	Alan Beckham	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Negative	<a href="#">View</a>
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Tom Foreman	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	

5	Manitoba Hydro	S N Fernando	Negative	<a href="#">View</a>
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego		
5	MidAmerican Energy Co.	Christopher Schneider		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern California Power Agency	Hari Modi	Abstain	
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	
5	Occidental Chemical	Michelle R DAntuono	Affirmative	<a href="#">View</a>
5	Oklahoma Gas and Electric Co.	Kim Morphis		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	Colin Anderson	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Gary L Tingley		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Fossil LLC	Mikhail Falkovich	Negative	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	RES Americas Inc	Ravi Bantu	Affirmative	<a href="#">View</a>
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Siemens PTI	Edwin Cano	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	<a href="#">View</a>
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M Helyer	Affirmative	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	<a href="#">View</a>
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Negative	<a href="#">View</a>
5	Xcel Energy, Inc.	Liam Noailles		
6	ACES Power Marketing	Jason L Marshall	Affirmative	<a href="#">View</a>
6	AEP Marketing	Edward P. Cox	Affirmative	<a href="#">View</a>
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	RANDY A YOUNG	Abstain	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirschak	Negative	
6	Colorado Springs Utilities	Lisa C Rosintoski	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Abstain	
6	Constellation Energy Commodities Group	Brenda Powell	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager		
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Negative	<a href="#">View</a>
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Luminant Energy	Brad Jones	Affirmative	

6	Manitoba Hydro	Daniel Prowse	Negative	<a href="#">View</a>
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Orlando Utilities Commission	Claston Augustus Sunanon	Affirmative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	<a href="#">View</a>
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Abstain	
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Edward C Stein	Affirmative	
8		James A Maenner	Abstain	
8		Roger C Zaklukiewicz	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Negative	
8	Power Energy Group LLC	Peggy Abbadini		
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Volkman Consulting, Inc.	Terry Volkman	Affirmative	
9	California Energy Commission	William M Chamberlain		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Affirmative	
9	New York State Department of Public Service	Thomas Dvorsky	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck	Abstain	
10	Florida Reliability Coordinating Council	Linda Campbell	Negative	<a href="#">View</a>
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Negative	<a href="#">View</a>
10	Southwest Power Pool RE	Emily Pennel	Affirmative	<a href="#">View</a>
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	<a href="#">View</a>
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	<a href="#">View</a>

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 Washington Office: 1120 G Street, N.W. : Suite 990 : Washington, DC 20005-3801

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Ballot Results	
<b>Ballot Name:</b>	Project 2010-07 PRC-004-2.1 Initial Ballot_rc
<b>Ballot Period:</b>	12/14/2011 - 12/23/2011
<b>Ballot Type:</b>	recirculation
<b>Total # Votes:</b>	331
<b>Total Ballot Pool:</b>	382
<b>Quorum:</b>	<b>86.65 % The Quorum has been reached</b>
<b>Weighted Segment Vote:</b>	96.43 %
<b>Ballot Results:</b>	<b>The Standard has Passed</b>

Summary of Ballot Results								
Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain	No Vote
			# Votes	Fraction	# Votes	Fraction	# Votes	
1 - Segment 1.	95	1	67	0.957	3	0.043	13	12
2 - Segment 2.	9	0.5	5	0.5	0	0	2	2
3 - Segment 3.	80	1	55	0.948	3	0.052	12	10
4 - Segment 4.	31	1	22	0.957	1	0.043	4	4
5 - Segment 5.	94	1	65	0.956	3	0.044	10	16
6 - Segment 6.	51	1	37	0.925	3	0.075	8	3
7 - Segment 7.	1	0	0	0	0	0	0	1
8 - Segment 8.	7	0.5	5	0.5	0	0	0	2
9 - Segment 9.	5	0.3	3	0.3	0	0	1	1
10 - Segment 10.	9	0.9	9	0.9	0	0	0	0
<b>Totals</b>	<b>382</b>	<b>7.2</b>	<b>268</b>	<b>6.943</b>	<b>13</b>	<b>0.257</b>	<b>50</b>	<b>51</b>

Individual Ballot Pool Results				
Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	<a href="#">Affirmative</a>	<a href="#">View</a>
1	American Electric Power	Paul B. Johnson	<a href="#">Affirmative</a>	<a href="#">View</a>
1	American Transmission Company, LLC	Andrew Z Pusztai	<a href="#">Affirmative</a>	
1	Arizona Public Service Co.	Robert Smith	<a href="#">Abstain</a>	
1	Associated Electric Cooperative, Inc.	John Bussman	<a href="#">Affirmative</a>	
1	Avista Corp.	Scott J Kinney	<a href="#">Affirmative</a>	
1	Balancing Authority of Northern California	Kevin Smith	<a href="#">Affirmative</a>	
1	BC Hydro and Power Authority	Patricia Robertson	<a href="#">Abstain</a>	

1	Beaches Energy Services	Joseph S Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	<a href="#">View</a>
1	East Kentucky Power Coop.	George S. Carruba	Abstain	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Abstain	
1	Georgia Transmission Corporation	Harold Taylor		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	<a href="#">View</a>
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Matthey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	<a href="#">View</a>
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Brett A Koelsch	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Duncel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	<a href="#">View</a>



1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	Santee Cooper	Terry L Blackwell	Abstain	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	<a href="#">View</a>
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Abstain	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Abstain	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	<a href="#">View</a>
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Vermont Electric Power Company, Inc.	Kim Moulton		
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox		
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles Yeung		
3	AEP	Michael E Deloach	Affirmative	<a href="#">View</a>
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	Anaheim Public Utilities Dept.	Kelly Nguyen	Abstain	
3	APS	Steven Norris	Abstain	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	<a href="#">View</a>
3	City of Alexandria	Michael Marcotte	Negative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Roseville	Susan E Gill-Zobitz	Abstain	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Abstain	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	<a href="#">View</a>
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia Systems Operations Corporation	William N. Phinney	Abstain	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Sam Kokkinen	Affirmative	<a href="#">View</a>
3	Gulf Power Company	Paul C Caldwell	Affirmative	



3	Harney Electric Cooperative, Inc.	Shane Sweet	<a href="#">Abstain</a>	
3	Holland Board of Public Works	William Bush	<a href="#">Affirmative</a>	
3	Hydro One Networks, Inc.	David Kiguel	<a href="#">Affirmative</a>	
3	Imperial Irrigation District	Jesus S. Alcaraz	<a href="#">Affirmative</a>	
3	JEA	Garry Baker	<a href="#">Affirmative</a>	
3	Kansas City Power & Light Co.	Charles Locke	<a href="#">Affirmative</a>	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik	<a href="#">Abstain</a>	
3	Louisville Gas and Electric Co.	Charles A. Freibert	<a href="#">Affirmative</a>	
3	Manitoba Hydro	Greg C. Parent	<a href="#">Negative</a>	<a href="#">View</a>
3	Mississippi Power	Jeff Franklin	<a href="#">Affirmative</a>	
3	Municipal Electric Authority of Georgia	Steven M. Jackson		
3	Muscatine Power & Water	John S Bos	<a href="#">Affirmative</a>	
3	Nebraska Public Power District	Tony Eddleman	<a href="#">Affirmative</a>	
3	New York Power Authority	Marilyn Brown	<a href="#">Affirmative</a>	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	<a href="#">Affirmative</a>	
3	Northern Indiana Public Service Co.	William SeDoris	<a href="#">Negative</a>	<a href="#">View</a>
3	NRG Energy Power Marketing, Inc.	Rick Keetch		
3	Ocala Electric Utility	David Anderson	<a href="#">Affirmative</a>	
3	Orange and Rockland Utilities, Inc.	David Burke	<a href="#">Affirmative</a>	
3	Oregon Trail Electric Cooperative	ned ratterman	<a href="#">Affirmative</a>	
3	Orlando Utilities Commission	Ballard K Mutters	<a href="#">Affirmative</a>	
3	Owensboro Municipal Utilities	Thomas T Lyons	<a href="#">Affirmative</a>	
3	Pacific Gas and Electric Company	John H Hagen	<a href="#">Affirmative</a>	
3	PacifiCorp	Dan Zollner	<a href="#">Affirmative</a>	
3	Platte River Power Authority	Terry L Baker	<a href="#">Affirmative</a>	
3	PNM Resources	Michael Mertz		
3	Potomac Electric Power Co.	Robert Reuter	<a href="#">Abstain</a>	
3	Progress Energy Carolinas	Sam Waters	<a href="#">Affirmative</a>	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	<a href="#">Affirmative</a>	
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	<a href="#">Affirmative</a>	<a href="#">View</a>
3	Sacramento Municipal Utility District	James Leigh-Kendall	<a href="#">Affirmative</a>	
3	Salt River Project	John T. Underhill	<a href="#">Affirmative</a>	
3	Santee Cooper	James M Poston	<a href="#">Abstain</a>	
3	Seattle City Light	Dana Wheelock	<a href="#">Affirmative</a>	<a href="#">View</a>
3	Seminole Electric Cooperative, Inc.	James R Frauen	<a href="#">Affirmative</a>	
3	Snohomish County PUD No. 1	Mark Oens		
3	South Carolina Electric & Gas Co.	Hubert C Young	<a href="#">Affirmative</a>	
3	Tacoma Public Utilities	Travis Metcalfe	<a href="#">Affirmative</a>	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	<a href="#">Affirmative</a>	
3	Tri-State G & T Association, Inc.	Janelle Marriott	<a href="#">Affirmative</a>	
3	Westar Energy	Bo Jones	<a href="#">Affirmative</a>	
3	Wisconsin Electric Power Marketing	James R Keller	<a href="#">Affirmative</a>	
3	Xcel Energy, Inc.	Michael Ibold	<a href="#">Affirmative</a>	
4	Alabama Municipal Electric Authority	Raymond Phillips	<a href="#">Affirmative</a>	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	<a href="#">Affirmative</a>	
4	American Municipal Power	Kevin Koloini	<a href="#">Affirmative</a>	
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	City of Clewiston	Kevin McCarthy	<a href="#">Affirmative</a>	
4	City of Redding	Nicholas Zettel	<a href="#">Affirmative</a>	
4	City Utilities of Springfield, Missouri	John Allen	<a href="#">Affirmative</a>	
4	Consumers Energy	David Frank Ronk	<a href="#">Abstain</a>	
4	Cowlitz County PUD	Rick Syring	<a href="#">Affirmative</a>	
4	Detroit Edison Company	Daniel Herring	<a href="#">Affirmative</a>	
4	Flathead Electric Cooperative	Russ Schneider	<a href="#">Negative</a>	
4	Florida Municipal Power Agency	Frank Gaffney	<a href="#">Affirmative</a>	
4	Fort Pierce Utilities Authority	Thomas Richards		
4	Georgia System Operations Corporation	Guy Andrews	<a href="#">Abstain</a>	
4	Imperial Irrigation District	Diana U Torres	<a href="#">Affirmative</a>	<a href="#">View</a>
4	Indiana Municipal Power Agency	Jack Alvey		
4	Integrus Energy Group, Inc.	Christopher Plante	<a href="#">Abstain</a>	
4	Madison Gas and Electric Co.	Joseph DePoorter	<a href="#">Affirmative</a>	
4	Modesto Irrigation District	Spencer Tacke		
4	North Carolina Electric Membership Corp.	Bob Beadle	<a href="#">Affirmative</a>	
4	Northern California Power Agency	Tracy R Bibb	<a href="#">Affirmative</a>	

4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	<a href="#">View</a>
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	<a href="#">View</a>
5	AEP Service Corp.	Brock Ondayko		
5	AES Corporation	Leo Bernier	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Wind Energy Association	Natalie McIntire	Affirmative	<a href="#">View</a>
5	Arizona Public Service Co.	Edward Cambridge		
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Bayer	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas	Abstain	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	
5	City of Tallahassee	Brian Horton	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy, Inc.	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Affirmative	<a href="#">View</a>
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	CPS Energy	Robert Stevens	Negative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	<a href="#">View</a>
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	East Kentucky Power Coop.	Stephen Ricker	Abstain	
5	Electric Power Supply Association	John R Cashin	Affirmative	
5	Energy Northwest - Columbia Generating Station	James Saucedo	Affirmative	
5	Entegra Power Group, LLC	Kenneth B Parker	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Green Country Energy	Greg Froehling	Affirmative	
5	Imperial Irrigation District	Marcela Y Caballero	Affirmative	
5	Indeck Energy Services, Inc.	Rex A Roehl	Affirmative	
5	Infigen Energy US	Pamela C Zdenek	Affirmative	<a href="#">View</a>
5	Invenergy LLC	Alan Beckham	Affirmative	
5	JEA	John J Babik		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Tom Foreman	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	

5	Manitoba Hydro	S N Fernando	Negative	<a href="#">View</a>
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego		
5	MidAmerican Energy Co.	Christopher Schneider		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern California Power Agency	Hari Modi	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	
5	Occidental Chemical	Michelle R DAntuono	Affirmative	<a href="#">View</a>
5	Oklahoma Gas and Electric Co.	Kim Morphis		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	Colin Anderson	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Gary L Tingley		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Fossil LLC	Mikhail Falkovich	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	<a href="#">View</a>
5	RES Americas Inc	Ravi Bantu	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Siemens PTI	Edwin Cano	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M Helyer	Affirmative	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles		
6	ACES Power Marketing	Jason L Marshall	Affirmative	<a href="#">View</a>
6	AEP Marketing	Edward P. Cox	Affirmative	<a href="#">View</a>
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	RANDY A YOUNG	Abstain	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirschak	Negative	
6	Colorado Springs Utilities	Lisa C Rosintoski	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Brenda Powell	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager		
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Luminant Energy	Brad Jones	Affirmative	

6	Manitoba Hydro	Daniel Prowse	Negative	<a href="#">View</a>
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Orlando Utilities Commission	Claston Augustus Sunanon	Affirmative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	<a href="#">View</a>
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Abstain	
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein	Affirmative	
8		James A Maenner	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini		
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Volkman Consulting, Inc.	Terry Volkman	Affirmative	
9	California Energy Commission	William M Chamberlain		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Affirmative	
9	New York State Department of Public Service	Thomas Dvorsky	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck	Abstain	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	<a href="#">View</a>
10	Southwest Power Pool RE	Emily Pennel	Affirmative	<a href="#">View</a>
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	<a href="#">View</a>

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## A. Introduction

1. **Title:** **Facility Connection Requirements**
2. **Number:** FAC-001-1
3. **Purpose:** To avoid adverse impacts on reliability, Transmission Owners and Generator Owners must establish Facility connection and performance requirements.
4. **Applicability:**
  - 4.1. Transmission Owner
  - 4.2. Applicable Generator Owner
    - 4.2.1 Generator Owner with an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems.
5. **Effective Date:**
  - 5.1. In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner and Regional Entity become effective upon Board of Trustees' adoption.
  - 5.2. In those jurisdictions where regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities. In those jurisdictions where no regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after Board of Trustees' adoption.

## B. Requirements

- R1. The Transmission Owner shall document, maintain, and publish Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, 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:
  - 1.1. Generation Facilities,
  - 1.2. Transmission Facilities, and
  - 1.3. End-user Facilities

*[VRF – Medium]*
- R2. Each applicable Generator Owner shall, within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems (under FAC-002-1), document and publish its Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, subregional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements.

*[VRF – Medium]*

- R3.** Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) shall address the following items in its Facility connection requirements:
- 3.1.** Provide a written summary of its plans to achieve the required system performance as described in Requirements R1 or R2 throughout the planning horizon:
- 3.1.1.** Procedures for coordinated joint studies of new Facilities and their impacts on the interconnected Transmission systems.
  - 3.1.2.** Procedures for notification of new or modified Facilities to others (those responsible for the reliability of the interconnected Transmission systems) as soon as feasible.
  - 3.1.3.** Voltage level and MW and MVAR capacity or demand at point of connection.
  - 3.1.4.** Breaker duty and surge protection.
  - 3.1.5.** System protection and coordination.
  - 3.1.6.** Metering and telecommunications.
  - 3.1.7.** Grounding and safety issues.
  - 3.1.8.** Insulation and insulation coordination.
  - 3.1.9.** Voltage, Reactive Power, and power factor control.
  - 3.1.10.** Power quality impacts.
  - 3.1.11.** Equipment Ratings.
  - 3.1.12.** Synchronizing of Facilities.
  - 3.1.13.** Maintenance coordination.
  - 3.1.14.** Operational issues (abnormal frequency and voltages).
  - 3.1.15.** Inspection requirements for existing or new Facilities.
  - 3.1.16.** Communications and procedures during normal and emergency operating conditions.

*[VRF – Medium]*

- R4.** 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, the Regional Entity, and ERO on request (five business days).

*[VRF – Medium]*

**C. Measures**

- M1.** The Transmission Owner shall make available (to its Compliance Enforcement Authority) evidence that it met all the requirements stated in Requirement R1.

- M2.** Each Generator Owner that has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems shall make available (to its Compliance Enforcement Authority) evidence that it met all requirements stated in Requirement R2.
- M3.** Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) shall make available (to its Compliance Enforcement Authority) evidence that it met all requirements stated in Requirement R3.
- M4.** The Transmission Owner shall make available (to its Compliance Enforcement Authority) evidence that it met all the requirements stated in Requirement R4.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

Compliance Monitor: Regional Entity

**1.2. Compliance Monitoring and Enforcement Processes:**

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

**1.3. Data Retention**

The Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Owner shall retain evidence of Requirement R1, Measure M1, Requirement R3, Measure M3, and Requirement R4, Measure M4 from its last audit.

The Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain evidence of Requirement R2, Measure M2, and Requirement R3, Measure M3 from its last audit.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Additional Compliance Information**

None.



2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Not Applicable.	<p>The Transmission Owner failed to do one of the following:</p> <p>Document or maintain or publish Facility connection requirements as specified in the Requirement</p> <p>OR</p> <p>Failed to include one (1) of the components as specified in R1.1, R1.2 or R1.3.</p>	<p>The Transmission Owner failed to do one of the following:</p> <p>Failed to include (2) of the components as specified in R1.1, R1.2 or R1.3</p> <p>OR</p> <p>Failed to document or maintain or publish its Facility connection requirements as specified in the Requirement <b>and</b> failed to include one (1) of the components as specified in R1.1, R1.2 or R1.3.</p>	The Transmission Owner did not develop Facility connection requirements.
R2	The Generator Owner failed to document and publish Facility connection requirements until more than 45 calendar days but less than or equal to 60 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the interconnected Transmission systems.	The Generator Owner failed to document and publish Facility connection requirements until more than 60 calendar days but less than or equal to 70 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the interconnected Transmission systems.	The Generator Owner failed to document and publish Facility connection requirements until more than 70 calendar days but less than or equal to 80 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the interconnected Transmission systems.	The Generator Owner failed to document and publish Facility connection requirements until more than 80 days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the interconnected Transmission systems.
R3	The responsible entity’s Facility connection	The responsible entity’s Facility connection	The responsible entity’s Facility connection	The responsible entity’s Facility connection

	requirements failed to address one of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.	requirements failed to address two of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.	requirements failed to address three of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.	requirements failed to address four or more of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.
R4	The responsible entity made the requirements available more than five business days but less than or equal to 10 business days after a request.	The responsible entity made the requirements available more than 10 business days but less than or equal to 20 business days after a request.	The responsible entity made the requirements available more than 20 business days less than or equal to 30 business days after a request.	The responsible entity made the requirements available more than 30 business days after a request.

**E. Regional Differences**

1. None identified.

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	TBD	Added requirements for Generator Owner and brought overall standard format up to date.	Revision under Project 2010-07

## A. Introduction

1. **Title:** **Facility Connection Requirements**
2. **Number:** FAC-001-1
3. **Purpose:** To avoid adverse impacts on reliability, Transmission Owners and Generator Owners must establish Facility connection and performance requirements.
4. **Applicability:**
  - 4.1. Transmission Owner
  - 4.2. Applicable Generator Owner
    - 4.2.1 Generator Owner with an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems.
5. **Effective Date:**
  - 5.1. In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner and Regional Entity become effective upon Board of Trustees' adoption.
  - 5.2. In those jurisdictions where regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities. In those jurisdictions where no regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after Board of Trustees' adoption.

## B. Requirements

- R1. The Transmission Owner shall document, maintain, and publish Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, 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:
  - 1.1. Generation Facilities,
  - 1.2. Transmission Facilities, and
  - 1.3. End-user Facilities

*[VRF – Medium]*
- R2. Each applicable Generator Owner shall, within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems (under FAC-002-1), document and publish its Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, subregional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements.

*[VRF – Medium]*

**R3.** Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) shall address the following items in its Facility connection requirements:

**3.1.** Provide a written summary of its plans to achieve the required system performance as described in Requirements R1 or R2 throughout the planning horizon:

**3.1.1.** Procedures for coordinated joint studies of new Facilities and their impacts on the interconnected Transmission systems.

**3.1.2.** Procedures for notification of new or modified Facilities to others (those responsible for the reliability of the interconnected Transmission systems) as soon as feasible.

**3.1.3.** Voltage level and MW and MVAR capacity or demand at point of connection.

**3.1.4.** Breaker duty and surge protection.

**3.1.5.** System protection and coordination.

**3.1.6.** Metering and telecommunications.

**3.1.7.** Grounding and safety issues.

**3.1.8.** Insulation and insulation coordination.

**3.1.9.** Voltage, Reactive Power, and power factor control.

**3.1.10.** Power quality impacts.

**3.1.11.** Equipment Ratings.

**3.1.12.** Synchronizing of Facilities.

**3.1.13.** Maintenance coordination.

**3.1.14.** Operational issues (abnormal frequency and voltages).

**3.1.15.** Inspection requirements for existing or new Facilities.

**3.1.16.** Communications and procedures during normal and emergency operating conditions.

*[VRF – Medium]*

**R4.** 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, the Regional Entity, and ERO on request (five business days).

*[VRF – Medium]*

**C. Measures**

**M1.** The Transmission Owner shall make available (to its Compliance Enforcement Authority) evidence that it met all the requirements stated in Requirement R1.

- M2.** Each Generator Owner that has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems shall make available (to its Compliance Enforcement Authority) evidence that it met all requirements stated in Requirement R2.
- M3.** Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) shall make available (to its Compliance Enforcement Authority) evidence that it met all requirements stated in Requirement R3.
- M4.** The Transmission Owner shall make available (to its Compliance Enforcement Authority) evidence that it met all the requirements stated in Requirement R4.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

Compliance Monitor: Regional Entity

**1.2. Compliance Monitoring and Enforcement Processes:**

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

**1.3. Data Retention**

The Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Owner shall retain evidence of Requirement R1, Measure M1, Requirement R3, Measure M3, and Requirement R4, Measure M4 from its last audit.

The Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain evidence of Requirement R2, Measure M2, and Requirement R3, Measure M3 from its last audit.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Additional Compliance Information**

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Not Applicable.	<p>The Transmission Owner failed to do one of the following:</p> <p>Document or maintain or publish <del>facility</del><u>Facility</u> connection requirements as specified in the Requirement</p> <p>OR</p> <p>Failed to include one (1) of the components <del>and</del><u>s</u> specified in R1.1, R1.2 or R1.3.</p>	<p>The Transmission Owner failed to do one of the following:</p> <p><del>Document or maintain or publish its facility connection requirements as specified in the Requirement.</del></p> <p>OR</p> <p>Failed to include (2) of the components as specified in R1.1, R1.2 or R1.3</p> <p>OR</p> <p>Failed to document or maintain or publish its <del>facility</del><u>Facility</u> connection requirements as specified in the Requirement <b>and</b> failed to include one (1) of the components as specified in R1.1, R1.2 or R1.3.</p>	<p>The Transmission Owner did not develop <del>facility</del><u>Facility</u> connection requirements.</p>
<u>R2</u>	<u>The Generator Owner failed to document and publish Facility connection requirements until more than 45 calendar days but less than or equal to 60 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's</u>	<u>The Generator Owner failed to document and publish Facility connection requirements until more than 60 calendar days but less than or equal to 70 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's</u>	<u>The Generator Owner failed to document and publish Facility connection requirements until more than 70 calendar days but less than or equal to 80 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's</u>	<u>(a) The Generator Owner failed to document and publish Facility connection requirements until more than 80 days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator</u>

	<u>existing Facility that is used to interconnect to the interconnected Transmission systems.</u>	<u>existing Facility that is used to interconnect to the interconnected Transmission systems.</u>	<u>existing Facility that is used to interconnect to the interconnected Transmission systems.</u>	<u>Owner's existing Facility that is used to interconnect to the interconnected Transmission systems.</u>
R3	<del>The Transmission Owner's facility responsible entity's Facility connection requirements failed to address one of the sub-requirements: parts listed in Requirement R3, parts 3.1.1 through 3.1.16.</del>	<del>The Transmission Owner's facility responsible entity's Facility connection requirements failed to address two of the sub-requirements: parts listed in Requirement R3, parts 3.1.1 through 3.1.16.</del>	<del>The Transmission Owner's facility responsible entity's Facility connection requirements failed to address three of the sub-requirements: parts listed in Requirement R3, parts 3.1.1 through 3.1.16.</del>	<del>The Transmission Owner's facility responsible entity's Facility connection requirements failed to address four or more of the sub-requirements: parts listed in Requirement R3, parts 3.1.1 through 3.1.16.</del>  <del>OR</del>  <del>The Transmission Owner does not have facility connection requirements.</del>
R4	The responsible entity made the requirements available more than five business days but less than or equal to 10 business days after a request.	The responsible entity made the requirements available more than 10 business days but less than or equal to 20 business days after a request.	The responsible entity made the requirements available more than 20 business days less than or equal to 30 business days after a request.	The responsible entity made the requirements available more than 30 business days after a request.

**E. Regional Differences**

1. None identified.

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	TBD	Added requirements for Generator Owner and brought overall standard format up to	Revision under Project 2010-07

Standard FAC-001-1 — Facility Connection Requirements

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		date.	



**Project 2010-07—Generator Requirements at the Transmission Interface  
Justification for Nonbinding Poll**

R#	Compliance with NERC's VSL Guidelines	<b>Guideline 1</b>  Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	<b>Guideline 2</b>  Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties  Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent  Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	<b>Guideline 3</b>  Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	<b>Guideline 4</b>  Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
FAC-001-1 R1	The drafting team made no changes to the R1 VSLs filed by NERC staff on March 21, 2011 (in Supplemental Information to the NERC Compliance Filing in Response to the Order on Violation Severity Levels Proposed by the ERO). Because the drafting team made no changes to R1, the team determined that any further changes to R1's VSLs would be outside of the scope of Project 2010-07.	The drafting team made no changes to the R1 VSLs filed by NERC staff on March 21, 2011 (in Supplemental Information to the NERC Compliance Filing in Response to the Order on Violation Severity Levels Proposed by the ERO), except to correct typographical errors.. Because the drafting team made no changes to R1, the team determined that any further changes to R1's VSLs would be outside of the scope of Project 2010-07.	The drafting team made no changes to the R1 VSLs filed by NERC staff on March 21, 2011 (in Supplemental Information to the NERC Compliance Filing in Response to the Order on Violation Severity Levels Proposed by the ERO), except to correct typographical errors. Because the drafting team made no changes to R1, the team determined that any further changes to R1's VSLs would be outside of the scope of Project 2010-07.	The drafting team made no changes to the R1 VSLs filed by NERC staff on March 21, 2011 (in Supplemental Information to the NERC Compliance Filing in Response to the Order on Violation Severity Levels Proposed by the ERO), except to correct typographical errors. Because the drafting team made no changes to R1, the team determined that any further changes to R1's VSLs would be outside of the scope of Project 2010-07.	The drafting team made no changes to the R1 VSLs filed by NERC staff on March 21, 2011 (in Supplemental Information to the NERC Compliance Filing in Response to the Order on Violation Severity Levels Proposed by the ERO), except to correct typographical errors. Because the drafting team made no changes to R1, the team determined that any further changes to R1's VSLs would be outside of the scope of Project 2010-07.
FAC-001-1 R2	The VSLs for R2 are written in accordance with NERC's VSL Guideline's formatting recommendations. The requirement is not of the pass/fail variety, so the VSL assignments have been gradated based on when the Generator Owner documented and published the Facility connection requirements. As is recommended by NERC's VSL Guidelines, the drafting team	Because this is a new requirement, there is no current level of compliance with which the VSL assignments can be compared.	The requirement has gradated VSLs; therefore, Guideline 2a is not applicable. The gradated VSLs ensure uniformity and consistency among all approved Reliability Standards in the determination of penalties.  The proposed text is clear, specific, and does not contain general, relative or subjective language (and is not subject to the	The drafting team compared the VSLs to the requirement language to ensure that the VSLs do not redefine or undermine the requirement's reliability goal. The VSL assignments are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.	The VSLs are based on a single violation, not on a cumulative number of violations of the same requirement over a period of time, thus fulfilling Guideline 4.

**Project 2010-07—Generator Requirements at the Transmission Interface  
Justification for Nonbinding Poll**

R#	Compliance with NERC’s VSL Guidelines	<b>Guideline 1</b>  Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	<b>Guideline 2</b>  Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties  Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent  Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	<b>Guideline 3</b>  Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	<b>Guideline 4</b>  Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
	identified a reasonable delay for the Lower VSL and then used 10-day increments to develop the Moderate, High, and Severe VSLs.		possibility of multiple interpretations), satisfying Guideline 2b.		
FAC-001-1 R3	For its proposed changes to VSLs for FAC-001-1 R3, the drafting team used the FERC-approved VSLs (then FAC-001-0 R2) in 135 FERC ¶ 61,166 as a starting point. The VSLs were already appropriately gradated with penalties based on the recommendation for requirements with parts that contribute equally to the requirement, and removing the second half of R3’s Severe VSL simply avoids any double jeopardy compliance issues, as indicated in the Guideline 2 explanation.	The drafting team’s slight modification to the Severe VSL for R3 does not signal a lower compliance threshold than previously existed.	The requirement has gradated VSLs; therefore, Guideline 2a is not applicable. The gradated VSLs ensure uniformity and consistency among all approved Reliability Standards in the determination of penalties.  The drafting team determined that the second half of the Severe VSL in R3 (“The responsible entity does not have Facility connection requirements”) could lead to double jeopardy because of its redundancy with the Severe VSLs in R1 (“The Transmission Owner did not develop Facility connection requirements”) and R2 (“The Generator Owner failed to document and publish and thereafter maintain Facility connection requirements until more than 80 days...”). Thus, the	The drafting team compared the VSLs to the requirement language to ensure that the VSLs do not redefine or undermine the requirement’s reliability goal. After modifying “Transmission Owner” to “responsibility entity”, the VSL assignments are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.	The VSLs are based on a single violation, not on a cumulative number of violations of the same requirement over a period of time, thus fulfilling Guideline 4.

**Project 2010-07—Generator Requirements at the Transmission Interface  
Justification for Nonbinding Poll**

R#	Compliance with NERC's VSL Guidelines	<b>Guideline 1</b>  Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	<b>Guideline 2</b>  Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties  Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent  Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	<b>Guideline 3</b>  Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	<b>Guideline 4</b>  Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
			second half of the VSL for R3 has been deleted.  With this change, the text is clear, specific, and does not contain general, relative or subjective language (and is not subject to the possibility of multiple interpretations), satisfying Guideline 2b.		
FAC-001-1 R4	The drafting team made no changes to the R4 VSLs (then VSLs for R3) approved by FERC in 135 FERC ¶ 61,166. Because, with this posting, the drafting team made no changes to R4 compared to the FERC approved version (then R3), the team determined that any further changes to R4's VSLs would be outside of the scope of Project 2010-07.	The drafting team made no changes to the R4 VSLs (then VSLs for R3) approved by FERC in 135 FERC ¶ 61,166. Because the drafting team made no changes to R4 compared to the FERC approved version (then R3), the team determined that any further changes to R4's VSLs would be outside of the scope of Project 2010-07.	The drafting team made no changes to the R4 VSLs (then VSLs for R3) approved by FERC in 135 FERC ¶ 61,166. Because the drafting team made no changes to R4 compared to the FERC approved version (then R3), the team determined that any further changes to R4's VSLs would be outside of the scope of Project 2010-07.	The drafting team made no changes to the R4 VSLs (then VSLs for R3) approved by FERC in 135 FERC ¶ 61,166. Because the drafting team made no changes to R4 compared to the FERC approved version (then R3), the team determined that any further changes to R4's VSLs would be outside of the scope of Project 2010-07.	The drafting team made no changes to the R4 VSLs (then VSLs for R3) approved by FERC in 135 FERC ¶ 61,166. Because the drafting team made no changes to R4 compared to the FERC approved version (then R3), the team determined that any further changes to R4's VSLs would be outside of the scope of Project 2010-07.

**VRFs for FAC-001-1:**

**Project 2010-07—Generator Requirements at the Transmission Interface  
Justification for Nonbinding Poll**

The VRFs for FAC-001-1 were transferred from NERC's VRF Matrix – which includes VRFs that have already been approved by FERC – to bring the formatting of the standard up to date. A Medium VRF was added to new Requirement R2, which applies to Generator Owners, to match the Medium VRF for the comparable Requirement R1, which applies to Transmission Owners.

# Implementation Plan for FAC-001-1—Facility Connection Requirements

## Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

## Revision to Sections of Approved Standards and Definitions

There are no proposed revisions to requirements in other already approved standards. FAC-001-0 – Facility Connection Requirements will be retired at midnight the day before FAC-001-1 becomes effective.

## Compliance with Standard

Since this version of the standard imposes no changes to Transmission Owners from those in the FERC-approved version of the standard, the expectation is that Transmission Owners will maintain their current state of compliance. Thus, the standard is effective for Transmission Owners upon approval, as detailed below.

The proposed changes to the FERC-approved version of this standard only address Generator Owner applicability and requirements (add Generator Owner to section 4.2, introduce a new requirement (R2), and modify one existing requirement (now R3)). Therefore, this implementation plan only identifies a compliance timeframe for Generator Owners to which this standard will apply.

## Effective Date

There are two effective dates associated with this standard:

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner and Regional Entity become effective upon Board of Trustees' adoption.

In those jurisdictions where regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities. In those jurisdictions where no regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after Board of Trustees' adoption.

# Standards Announcement

Project 2010-07

Generator Requirements at the Transmission Interface

Non-Binding Poll January 4 – 13, 2012

## [Now Available](#)

Over the last year, the Project 2010-07 Generator Requirements at the Transmission Interface SDT has proposed and vetted changes to FAC-001-1, FAC-003-X, FAC-003-3, and PRC-004-2.1. All four standards were approved by their respective ballot pools in recirculation ballots that ended on December 23, 2011. FAC-001, FAC-003-3, and PRC-004-2.1a (which includes the interpretation from PRC-004-2a) will be presented to the NERC Board of Trustees for approval in February 2012.

From January 4-13, 2012, the SDT will be conducting a non-binding poll of the VSLs and VRFs that were substantively revised. FAC-003-X's and PRC-004-2.1a's VSLs and VRFs were not revised at all and FAC-003-3's VSLs and VRFs were only edited to change the responsible entity in the VSLs, so only FAC-001-1's VSLs and VRFs are being posted for the non-binding poll.

### **Detail on Updates to VSLs and VRFs for FAC-001-1, FAC-003-X, FAC-003-3, and PRC-004-2.1a**

Because it was a Version 0 standard, FAC-001-0 did not initially have VSLs or VRFs assigned to it. The VSLs for FAC-001-1 were transferred from the VSLs filed by NERC staff on March 21, 2011 (in [Supplemental Information to the NERC Compliance Filing in Response to the Order on Violation Severity Levels Proposed by the ERO](#)). The VRFs for FAC-001-1 were transferred into the standard from NERC's [VRF Matrix](#) – which includes VRFs that have already been approved by FERC – to bring the format of the standard up to date. For existing Requirements R1 and R4 (applicable to Transmission Owners only), no substantive changes to VSLs or VRFs were made, although typographical errors in the VSLs for R1 was corrected. For new requirement R2 (applicable to Generator Owners only), the Project 2010-07 standard drafting team applied the comparable VRF from R1 and developed a set of VSLs according to NERC and FERC guidelines. For modified Requirement R3 (applicable to Transmission Owners and Generator Owners), no substantive changes to the VSLs or VRFs were made, although a typographical error in the VSLs for R3 was corrected and “Transmission Owner” was changed to “responsible entity.”

The proposed changes in FAC-003-3 serve only to make the standard applicable to qualifying Generator Owners, so no changes were proposed for the VRFs for FAC-003-3. The only modification proposed for the VSLs for FAC-003-3 was to change all references to “Transmission Owner” to “responsible entity.” The proposed change in PRC-004-2.1a Requirement R2 is a clarifying (errata) change that makes clear that generator interconnection Facilities are also part of Generator Owners' responsibility in the context of this standard. Thus, no changes were proposed for the VRFs or VSLs for PRC-004-2.1a.

### Instructions for Casting an Opinion in the Non-binding Poll

Members of the ballot pool associated with this project may log in and submit their opinion for the non-binding polls from the following page: <https://standards.nerc.net/CurrentBallots.aspx>

### Next Steps

FAC-001, FAC-003-3, and PRC-004-2.1a will be presented to the NERC Board of Trustees for adoption in February 2012, and information on the non-binding poll results will be provided to the Board for consideration in their decision.

### Background

The purpose of Project 2010-07 is to ensure that all generator-owned Facilities are appropriately covered under NERC's Reliability Standards. While many Generator Owners and Generator Operators operate Facilities, commonly known as generator interconnection Facilities, that are considered by some entities to be transmission, these are most often sole-use Facilities that are not part of the integrated grid. As such, they should not be subject to the same standards applicable to Transmission Owners and Transmission Operators who own and operate Transmission Elements and Facilities that are part of the integrated grid.

As part of the BES, generators do affect the overall reliability of the BES. But registering a Generator Owner or Generator Operator as a Transmission Owner or Transmission Operator, as has been the solution in some cases in the past, may decrease reliability by diverting the Generator Owner's or Generator Operator's resources from the operation of the equipment that actually produces electricity – the generation equipment itself.

The SDT's goal is to ensure that an adequate level of reliability is maintained in the BES by clearly describing which standards need to be applied to generator interconnection Facilities that are not already applicable to Generator Owners or Generator Operators. This can be accomplished by properly applying FAC-001, FAC-003, PRC-004, and later, PRC-005, to Generator Owners. Additional information is available on the [project page](#).

### Standards Process

The [Standard Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

*For more information or assistance, please contact Monica Benson,  
Standards Process Administrator, at [monica.benson@nerc.net](mailto:monica.benson@nerc.net) or at 404-446-2560.*

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# Non-binding Poll Results

Project 2010-07 Generator Requirements at the Transmission Interface

Ballot Results	
<b>Non-binding Poll Name:</b>	Project 2010-07 GOTO non-binding poll FAC-001-1
<b>Poll Period:</b>	1/4/2012 - 1/13/2012
<b>Total # Opinions:</b>	208
<b>Total Ballot Pool:</b>	382
<b>Summary Results:</b>	78.27% of those who registered to participate provided an opinion or abstention. 93% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results				
Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Abstain	
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Robert Smith		
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott J Kinney		
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejuna	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		

1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	George S. Carruba	Abstain	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor	Affirmative	<a href="#">View</a>
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza		
1	International Transmission Company Holdings Corp	Michael Moltane		
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon		
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour		
1	Nebraska Public Power District	Cole C Brodine		
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	Northeast Utilities	David Boguslawski	Abstain	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Matthey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	

1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Brett A Koelsch	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Affirmative	
1	Santee Cooper	Terry L Blackwell	Abstain	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Abstain	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Sierra Pacific Power Co.	Rich Salgo		
1	Snohomish County PUD No. 1	Long T Duong	Abstain	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	<a href="#">View</a>
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Vermont Electric Power Company, Inc.	Kim Moulton		
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	Alberta Electric System Operator	Mark B Thompson	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Marie Knox		
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe	Abstain	
2	Southwest Power Pool, Inc.	Charles Yeung	Negative	<a href="#">View</a>
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Richard J. Mandes	Affirmative	

3	Ameren Services	Mark Peters	Affirmative	
3	Anaheim Public Utilities Dept.	Kelly Nguyen	Abstain	
3	APS	Steven Norris	Abstain	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Alexandria	Michael Marcotte	Negative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Milla	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Abstain	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Roseville	Susan E Gill-Zobitz		
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy	Richard Blumenstock	Abstain	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	Entergy	Joel T Plessinger	Abstain	
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia Systems Operations Corporation	William N. Phinney	Negative	<a href="#">View</a>
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Harney Electric Cooperative, Inc.	Shane Sweet	Affirmative	
3	Holland Board of Public Works	William Bush	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	Imperial Irrigation District	Jesus S. Alcaraz	Abstain	
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	Mississippi Power	Jeff Franklin	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	

3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone		
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	NRG Energy Power Marketing, Inc.	Rick Keetch	Abstain	
3	Ocala Electric Utility	David Anderson		
3	Orange and Rockland Utilities, Inc.	David Burke	Abstain	
3	Oregon Trail Electric Cooperative	ned ratterman	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Potomac Electric Power Co.	Robert Reuter		
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens		
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey	Negative	
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Abstain	
3	Xcel Energy, Inc.	Michael Ibold		
4	Alabama Municipal Electric Authority	Raymond Phillips	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Clewiston	Kevin McCarthy	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk		
4	Cowlitz County PUD	Rick Syring		
4	Detroit Edison Company	Daniel Herring	Affirmative	

4	Flathead Electric Cooperative	Russ Schneider	Negative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas Richards	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Affirmative	
4	Integrays Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke	Affirmative	
4	North Carolina Electric Membership Corp.	Bob Beadle	Affirmative	
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	<a href="#">View</a>
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seattle City Light	Hao Li	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steven McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	AES Corporation	Leo Bernier		
5	Amerenue	Sam Dwyer	Affirmative	
5	American Wind Energy Association	Natalie McIntire	Abstain	
5	Arizona Public Service Co.	Edward Cambridge		
5	Avista Corp.	Edward F. Groce	Abstain	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Bayer	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas		
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	
5	City of Tallahassee	Brian Horton		
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	

5	Cleco Power	Stephanie Huffman	Affirmative	
5	Cogentrix Energy, Inc.	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad		
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex		
5	CPS Energy	Robert Stevens		
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	East Kentucky Power Coop.	Stephen Ricker	Abstain	
5	Electric Power Supply Association	John R Cashin	Affirmative	
5	Energy Northwest - Columbia Generating Station	James Saucedo		
5	Entegra Power Group, LLC	Kenneth B Parker	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Green Country Energy	Greg Froehling	Affirmative	
5	Imperial Irrigation District	Marcela Y Caballero		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	Infigen Energy US	Pamela C Zdenek		
5	Invenergy LLC	Alan Beckham		
5	JEA	John J Babik	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Abstain	
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom		
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman	Abstain	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	

5	New York Power Authority	Gerald Mannarino	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern California Power Agency	Hari Modi		
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	<a href="#">View</a>
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oklahoma Gas and Electric Co.	Kim Morphis		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	Colin Anderson	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Abstain	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Fossil LLC	Mikhail Falkovich	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	RES Americas Inc	Ravi Bantu		
5	Sacramento Municipal Utility District	Bethany Hunter	Abstain	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes		
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Siemens PTI	Edwin Cano	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M Helyer	Affirmative	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles		
6	ACES Power Marketing	Jason L Marshall	Negative	<a href="#">View</a>
6	AEP Marketing	Edward P. Cox	Abstain	<a href="#">View</a>
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	RANDY A YOUNG	Abstain	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Abstain	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Lisa C Rosintoski	Affirmative	
6	Consolidated Edison Co. of New	Nickesha P Carrol	Abstain	



	York			
6	Constellation Energy Commodities Group	Brenda Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit		
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Negative	
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson		
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	Scott L Smith	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet		
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Abstain	
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Negative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		

6	Xcel Energy, Inc.	David F. Lemmons		
7	Siemens Energy, Inc.	Frank R. McElvain	Affirmative	
8		James A Maenner		
8		Edward C Stein	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Abstain	
8	Power Energy Group LLC	Peggy Abbadini		
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkman Consulting, Inc.	Terry Volkman	Affirmative	
9	California Energy Commission	William M Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney		
9	New York State Department of Public Service	Thomas Dvorsky		
9	Public Utilities Commission of Ohio	Klaus Lambeck		
10	Florida Reliability Coordinating Council	Linda Campbell		
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	<a href="#">View</a>
10	SERC Reliability Corporation	Carter B. Edge	Abstain	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

## A. Introduction

1. **Title:** **Facility Connection Requirements**
2. **Number:** FAC-001-1
3. **Purpose:** To avoid adverse impacts on reliability, Transmission Owners and Generator Owners must establish Facility connection and performance requirements.
4. **Applicability:**
  - 4.1. Transmission Owner
  - 4.2. Applicable Generator Owner
    - 4.2.1 Generator Owner with an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems.
5. **Effective Date:**
  - 5.1. In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner and Regional Entity become effective upon Board of Trustees' adoption.
  - 5.2. In those jurisdictions where regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities. In those jurisdictions where no regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after Board of Trustees' adoption.

## B. Requirements

- R1. The Transmission Owner shall document, maintain, and publish Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, 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:
  - 1.1. Generation Facilities,
  - 1.2. Transmission Facilities, and
  - 1.3. End-user Facilities

*[VRF – Medium]*
- R2. Each applicable Generator Owner shall, within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems (under FAC-002-1), document and publish its Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, subregional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements.

*[VRF – Medium]*

- R3.** Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) shall address the following items in its Facility connection requirements:
- 3.1.** Provide a written summary of its plans to achieve the required system performance as described in Requirements R1 or R2 throughout the planning horizon:
- 3.1.1.** Procedures for coordinated joint studies of new Facilities and their impacts on the interconnected Transmission systems.
  - 3.1.2.** Procedures for notification of new or modified Facilities to others (those responsible for the reliability of the interconnected Transmission systems) as soon as feasible.
  - 3.1.3.** Voltage level and MW and MVAR capacity or demand at point of connection.
  - 3.1.4.** Breaker duty and surge protection.
  - 3.1.5.** System protection and coordination.
  - 3.1.6.** Metering and telecommunications.
  - 3.1.7.** Grounding and safety issues.
  - 3.1.8.** Insulation and insulation coordination.
  - 3.1.9.** Voltage, Reactive Power, and power factor control.
  - 3.1.10.** Power quality impacts.
  - 3.1.11.** Equipment Ratings.
  - 3.1.12.** Synchronizing of Facilities.
  - 3.1.13.** Maintenance coordination.
  - 3.1.14.** Operational issues (abnormal frequency and voltages).
  - 3.1.15.** Inspection requirements for existing or new Facilities.
  - 3.1.16.** Communications and procedures during normal and emergency operating conditions.

*[VRF – Medium]*

- R4.** 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, the Regional Entity, and ERO on request (five business days).

*[VRF – Medium]*

## **C. Measures**

- M1.** The Transmission Owner shall make available (to its Compliance Enforcement Authority) evidence that it met all the requirements stated in Requirement R1.

- M2.** Each Generator Owner that has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems shall make available (to its Compliance Enforcement Authority) evidence that it met all requirements stated in Requirement R2.
- M3.** Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) shall make available (to its Compliance Enforcement Authority) evidence that it met all requirements stated in Requirement R3.
- M4.** The Transmission Owner shall make available (to its Compliance Enforcement Authority) evidence that it met all the requirements stated in Requirement R4.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

Compliance Monitor: Regional Entity

**1.2. Compliance Monitoring and Enforcement Processes:**

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

**1.3. Data Retention**

The Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Owner shall retain evidence of Requirement R1, Measure M1, Requirement R3, Measure M3, and Requirement R4, Measure M4 from its last audit.

The Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain evidence of Requirement R2, Measure M2, and Requirement R3, Measure M3 from its last audit.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Additional Compliance Information**

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Not Applicable.	<p>The Transmission Owner failed to do one of the following:</p> <p>Document or maintain or publish Facility connection requirements as specified in the Requirement</p> <p>OR</p> <p>Failed to include one (1) of the components as specified in R1.1, R1.2 or R1.3.</p>	<p>The Transmission Owner failed to do one of the following:</p> <p>Failed to include (2) of the components as specified in R1.1, R1.2 or R1.3</p> <p>OR</p> <p>Failed to document or maintain or publish its Facility connection requirements as specified in the Requirement <b>and</b> failed to include one (1) of the components as specified in R1.1, R1.2 or R1.3.</p>	The Transmission Owner did not develop Facility connection requirements.
R2	The Generator Owner failed to document and publish Facility connection requirements until more than 45 calendar days but less than or equal to 60 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the interconnected Transmission systems.	The Generator Owner failed to document and publish Facility connection requirements until more than 60 calendar days but less than or equal to 70 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the interconnected Transmission systems.	The Generator Owner failed to document and publish Facility connection requirements until more than 70 calendar days but less than or equal to 80 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the interconnected Transmission systems.	The Generator Owner failed to document and publish Facility connection requirements until more than 80 days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the interconnected Transmission systems.
R3	The responsible entity’s Facility connection	The responsible entity’s Facility connection	The responsible entity’s Facility connection	The responsible entity’s Facility connection

	requirements failed to address one of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.	requirements failed to address two of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.	requirements failed to address three of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.	requirements failed to address four or more of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.
R4	The responsible entity made the requirements available more than five business days but less than or equal to 10 business days after a request.	The responsible entity made the requirements available more than 10 business days but less than or equal to 20 business days after a request.	The responsible entity made the requirements available more than 20 business days less than or equal to 30 business days after a request.	The responsible entity made the requirements available more than 30 business days after a request.

**E. Regional Differences**

1. None identified.

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	TBD	Added requirements for Generator Owner and brought overall standard format up to date.	Revision under Project 2010-07

**B.A. Introduction**

1. **Title:** Facility Connection Requirements
2. **Number:** FAC-001-~~0~~1
3. **Purpose:**- To avoid adverse impacts on reliability, Transmission Owners and Generator Owners must establish ~~facility~~Facility connection and performance requirements.
4. **Applicability:**
  - 4.1. Transmission Owner
  - 4.2. Applicable Generator Owner
    - 4.2.1 Generator Owner with an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems.
5. **Effective Date:**— ~~April 1, 2005~~
  - 5.1. In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner and Regional Entity become effective upon Board of Trustees' adoption.
  - 5.2. In those jurisdictions where regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities. In those jurisdictions where no regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after Board of Trustees' adoption.

**C.B. Requirements**

- R1.** The Transmission Owner shall document, maintain, and publish ~~facility~~Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional ~~Reliability Organization~~Entity, subregional, Power Pool, and individual Transmission Owner planning criteria and ~~facility~~Facility connection requirements. The Transmission Owner's ~~facility~~Facility connection requirements shall address connection requirements for:
  - R1.1.1.1. Generation ~~facilities~~Facilities,
  - R1.2.1.2. Transmission ~~facilities~~Facilities, and
  - R1.3.1.3. End-user ~~facilities~~Facilities
- ~~R2.~~ The Transmission Owner's facility connection requirements shall address, but are not limited to, the following items:

*[VRF – Medium]*
- R2. Each applicable Generator Owner shall, within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems (under FAC-002-1), document and publish its Facility connection requirements to



ensure compliance with NERC Reliability Standards and applicable Regional Entity, subregional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements.

*[VRF – Medium]*

**R3.** Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) shall address the following items in its Facility connection requirements:

**R2.1.3.1.** Provide a written summary of its plans to achieve the required system performance as described ~~above~~ in Requirements R1 or R2 throughout the planning horizon:

**R2.1.1.3.1.1.** Procedures for coordinated joint studies of new ~~faeilities~~Facilities and their impacts on the interconnected ~~transmission~~Transmission systems.

**R2.1.2.3.1.2.** Procedures for notification of new or modified ~~faeilities~~Facilities to others (those responsible for the reliability of the interconnected ~~transmission~~Transmission systems) as soon as feasible.

**R2.1.3.3.1.3.** Voltage level and MW and MVAR capacity or demand at point of connection.

**R2.1.4.3.1.4.** Breaker duty and surge protection.

**R2.1.5.3.1.5.** System protection and coordination.

**R2.1.6.3.1.6.** Metering and telecommunications.

**R2.1.7.3.1.7.** Grounding and safety issues.

**R2.1.8.3.1.8.** Insulation and insulation coordination.

**R2.1.9.3.1.9.** Voltage, Reactive Power, and power factor control.

**R2.1.10.3.1.10.** Power quality impacts.

**R2.1.11.3.1.11.** Equipment Ratings.

**R2.1.12.3.1.12.** Synchronizing of ~~faeilities~~Facilities.

**R2.1.13.3.1.13.** Maintenance coordination.

**R2.1.14.3.1.14.** Operational issues (abnormal frequency and voltages).

**R2.1.15.3.1.15.** Inspection requirements for existing or new ~~faeilities~~Facilities.

**R2.1.16.3.1.16.** Communications and procedures during normal and emergency operating conditions.

*[VRF – Medium]*

**R3-R4.** The Transmission Owner shall maintain and update its ~~faeility~~Facility connection requirements as required. - The Transmission Owner shall make documentation of these requirements available to the users of the transmission system, the Regional ~~Reliability Organization~~Entity, and ~~NERC~~ERO on request (five business days).

[VRF – Medium]

#### D.C. Measures

- M1.** The Transmission Owner shall make available (to its Compliance ~~Monitor~~) for inspection Enforcement Authority evidence that it met all the requirements stated in Reliability Standard FAC-001-0-Requirement R1.
- M2.** ~~The~~Each Generator Owner that has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission ~~Owners~~systems shall make available (to its Compliance ~~Monitor~~) for inspection Enforcement Authority evidence that it met all requirements stated in Reliability Standard FAC-001-0-Requirement R2.
- M3.** ~~The~~Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) shall make available (to its Compliance ~~Monitor~~) for inspection Enforcement Authority evidence that it met all ~~the~~ requirements stated in Reliability Standard FAC-001-0-R3 Requirement R3.
- M3.M4.** The Transmission Owner shall make available (to its Compliance Enforcement Authority) evidence that it met all the requirements stated in Requirement R4.

#### E.D. Compliance

##### **1. Compliance Monitoring Process**

###### **1.1. Compliance ~~Monitoring Responsibility~~ Enforcement Authority**

Compliance Monitor: Regional ~~Reliability Organization~~ Entity

###### **1.2. Compliance Monitoring ~~Period~~ and ~~Reset~~ Timeframe Enforcement Processes:**

~~On request (five business days):~~

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

###### **1.3. Data Retention**

~~None specified:~~

The Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Owner shall retain evidence of Requirement R1, Measure M1, Requirement R3, Measure M3, and Requirement R4, Measure M4 from its last audit.

The Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain evidence of Requirement R2, Measure M2, and Requirement R3, Measure M3 from its last audit.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Additional Compliance Information**

None.

**2. Violation Severity 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.~~

<u>R #</u>	<u>Lower VSL</u>	<u>Moderate VSL</u>	<u>High VSL</u>	<u>Severe VSL</u>
<u>R1</u>	<u>Not Applicable.</u>	<u>The Transmission Owner failed to do one of the following:</u>  <u>Document or maintain or publish Facility connection requirements as specified in the Requirement</u>  <u>OR</u>  <u>Failed to include one</u>	<u>The Transmission Owner failed to do one of the following:</u>  <u>Failed to include (2) of the components as specified in R1.1, R1.2 or R1.3</u>  <u>OR</u>  <u>Failed to document or maintain or publish its Facility connection</u>	<u>The Transmission Owner did not develop Facility connection requirements.</u>

		<u>(1) of the components as specified in R1.1, R1.2 or R1.3.</u>	<u>requirements as specified in the Requirement and failed to include one (1) of the components as specified in R1.1, R1.2 or R1.3.</u>	
<u>R2</u>	<u>The Generator Owner failed to document and publish Facility connection requirements until more than 45 calendar days but less than or equal to 60 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems.</u>	<u>The Generator Owner failed to document and publish Facility connection requirements until more than 60 calendar days but less than or equal to 70 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems.</u>	<u>The Generator Owner failed to document and publish Facility connection requirements until more than 70 calendar days but less than or equal to 80 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems.</u>	<u>The Generator Owner failed to document and publish Facility connection requirements until more than 80 days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems.</u>
<u>R3</u>	<u>The responsible entity's Facility connection requirements failed to address one of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.</u>	<u>The responsible entity's Facility connection requirements failed to address two of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.</u>	<u>The responsible entity's Facility connection requirements failed to address three of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.</u>	<u>The responsible entity's Facility connection requirements failed to address four or more of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.</u>
<u>R4</u>	<u>The responsible entity made the requirements available more than five business days but less than or equal to 10 business days after a request.</u>	<u>The responsible entity made the requirements available more than 10 business days but less than or equal to 20 business days after a request.</u>	<u>The responsible entity made the requirements available more than 20 business days less than or equal to 30 business days after a request.</u>	<u>The responsible entity made the requirements available more than 30 business days after a request.</u>

**P.E. Regional Differences**

1. None identified.

### Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
<u>1</u>	<u>TBD</u>	<u>Added requirements for Generator Owner and brought overall standard format up to date.</u>	<u>Revision under Project 2010-07</u>

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# Implementation Plan for FAC-001-1—Facility Connection Requirements

## **Prerequisite Approvals**

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

## **Revision to Sections of Approved Standards and Definitions**

There are no proposed revisions to requirements in other already approved standards. FAC-001-0 – Facility Connection Requirements will be retired at midnight the day before FAC-001-1 becomes effective.

## **Compliance with Standard**

Since this version of the standard imposes no changes to Transmission Owners from those in the FERC-approved version of the standard, the expectation is that Transmission Owners will maintain their current state of compliance. Thus, the standard is effective for Transmission Owners upon approval, as detailed below.

The proposed changes to the FERC-approved version of this standard only address Generator Owner applicability and requirements (add Generator Owner to section 4.2, introduce a new requirement (R2), and modify one existing requirement (now R3)). Therefore, this implementation plan only identifies a compliance timeframe for Generator Owners to which this standard will apply.

## **Effective Date**

There are two effective dates associated with this standard:

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner and Regional Entity become effective upon Board of Trustees' adoption.

In those jurisdictions where regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities. In those jurisdictions where no regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after Board of Trustees' adoption.

## Standard PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

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### A. Introduction

1. **Title:** Analysis and Mitigation of Transmission and Generation Protection System Misoperations
2. **Number:** PRC-004-2.1a
3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.
4. **Applicability**
  - 4.1. Transmission Owner.
  - 4.2. Distribution Provider that owns a transmission Protection System.
  - 4.3. Generator Owner.
5. **(Proposed) Effective Date:** In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements become effective upon Board of Trustees' adoption.

### B. Requirements

- R1.** The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- R2.** The Generator Owner shall analyze its generator and generator interconnection Facility Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- R3.** The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.

### C. Measures

- M1.** The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- M2.** The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- M3.** Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Entity's procedures.

### D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Enforcement Authority**

Regional Entity.

## Standard PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

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### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

### 1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

### 1.4. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation or generator interconnection Facility Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

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

### 1.5. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

## 2. Violation Severity Levels (no changes)

### E. Regional Differences

None identified.

### Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	<ol style="list-style-type: none"> <li>1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>2. Added “periods” to items where appropriate.</li> </ol> Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
2	TBD	Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised.
2.1a	XX	Errata change: Edited R2 to add “...and generator interconnection Facility...”	Revision under Project 2010-07



## Standard PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

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### A. Introduction

1. **Title:** Analysis and Mitigation of Transmission and Generation Protection System Misoperations
2. **Number:** PRC-004-2.1a
3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.
4. **Applicability**
  - 4.1. Transmission Owner.
  - 4.2. Distribution Provider that owns a transmission Protection System.
  - 4.3. Generator Owner.
5. **(Proposed) Effective Date:** ~~The first day of the first calendar quarter, one year after applicable~~ In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year after all requirements become effective upon Board of Trustees' adoption. \_\_

### B. Requirements

- R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- R2. The Generator Owner shall analyze its generator and generator interconnection Facility Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.

### C. Measures

- M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Entity's procedures.

### D. Compliance

1. **Compliance Monitoring Process**

**Standard PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations**

**1.1. Compliance Enforcement Authority**

Regional Entity.

**1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

**1.3. Compliance Monitoring and Enforcement Processes:**

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.4. Data Retention**

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation or generator interconnection Facility Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

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

**1.5. Additional Compliance Information**

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

**2. Violation Severity Levels (no changes)**

**E. Regional Differences**

None identified.

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
2	TBD	Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised.
<u>2.1a</u>	<u>XX</u>	<u>Errata change: Edited R2 to add “...and</u>	<u>Revision under Project</u>

**Standard PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations**

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		<u>generator interconnection Facility...”</u>	<u>2010-07</u>
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# Implementation Plan for PRC-004-2.1a— Analysis of Transmission and Generation Protection System Misoperations

## **Prerequisite Approvals**

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

## **Revision to Sections of Approved Standards and Definitions**

There are no proposed revisions to requirements in other already approved standards. PRC-004-2a will be retired when PRC-004-2.1a becomes effective.

## **Compliance with Standard**

The proposed change to Requirement R2 is a clarifying change. While there was no reliability gap in the previous version of the standard, if applied literally, there was the possibility for the misperception that the Generator Owner was only responsible for analyzing its generator Protection System Misoperations, exclusive of its generator interconnection Facility. The errata change to R2 makes clear that generator interconnection Facilities are also part of Generator Owners' responsibility in the context of this standard.

Because the change is merely a clarifying change, no additional time for compliance is needed.

## **Effective Date**

In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements become effective upon Board of Trustees' adoption.

# Technical Justification Resource Document

## Project 2010-07 Generator Requirements at the Transmission Interface

### Background

As part of its work on Project 2010-07—Generator Requirements at the Transmission Interface, the standard drafting team (SDT) reviewed 34 reliability standards and 102 requirements to determine what changes are necessary to close a reliability gap with respect to what is commonly known as the generator interconnection Facility. Many of these standards and requirements had been addressed in the [Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface](#) (Ad Hoc Report) and additional standards were reviewed as a result of informal discussions with NERC and FERC staffs.

The basis for standard modifications recommended by the Ad Hoc Group for Generator Requirements at the Transmission Interface (Ad Hoc Group) was a few fundamental clarifications to the definitions of Generator Owner, Generator Operator, and Transmission, along with the creation of new definitions: one for Generator Interconnection Facility and one for Generator Interconnection Operational Interface. The Ad Hoc Group proposed the addition of these two new definitions to 26 standards encompassing 29 requirements (new and old), along with some modifications to FAC-003 to make it applicable to Generator Owners under certain circumstances.

Since the publication of the Ad Hoc Report, various entities have challenged these modifications and the recommended creation of the new definitions. The SDT has developed a more focused approach than that of the Ad Hoc Group: to propose recommendations whereby sole-use interconnection Facilities (at or above 100 kV) that are owned and operated by generating entities will be included in a small set of standards and requirements previously only applicable to Transmission Owners. The SDT agrees completely with the Ad Hoc Group's conclusion that Generator Owners and Operators of these sole-use generator tie-line Facilities (at voltages equal to or greater than 100 kV) should not be registered as Transmission Owners and Transmission Operators in order to maintain reliability on the Bulk Electric System (BES).

The SDT's justification for this strategy is rooted in the very title of its standards project: "Generator Requirements at the Transmission Interface." That is, the goal and scope of the project has always been to determine the responsibilities of those Generator Owners and Generator Operators that own or operate an interconnection Facility (in some cases labeled a "transmission Facility") between the generator and the interface with the portion of the BES where Transmission Owners and Transmission Operators take over ownership and operating responsibility. These kinds of Generator Owners and Generator Operators do not own or operate Facilities that are part of the interconnected system; rather, they own and operate sole-use Facilities that are connected to the boundary of the

interconnected system and as such have a limited role in providing reliability compared to those that operate in a networked fashion beyond the point of interconnection.

While some argue that these interconnecting portions of a Generator Owner's Facilities could be defined as Transmission and thus require the Generator Owner and Generator Operator for the Facility to be classified and registered as a Transmission Owner and Transmission Operator, the SDT does not believe this is necessary to provide an appropriate level of reliability for the BES. Just as important, such classification and registration could actually cause a reduction in reliability. Generator Owners and Generator Operators do not need, and in some cases may be prohibited from having, a wide-area view and responsibility for the integrated transmission system. Requiring Generator Owners and Generator Operators to have such responsibilities would require significant training, require substantially more data and modeling responsibilities, and detract from the entities' primary functions: to own and operate their generation equipment – including any Facilities owned and operated at voltages of 100 kV or greater that connect to the interconnected system – in a reliable manner.

Additionally, the SDT believes that the industry is much more aware today of the need to include *all* elements (owned and operated at 100 kV or higher) of a generator Facility in the procedures and compliance program of the registered entity that owns or has operational responsibility of those elements. Industry awareness was raised substantially at the time the [October 17, 2010 Facility Ratings Recommendation to Industry](#) was issued (which included Generator Owners and specifically addressed interconnection Facilities in [the Q&A document](#) with the statement that the alert applied to generator interconnection tie lines that are radial only and do not serve load “if the generator is considered part of the bulk electric system”). While this applies to a specific NERC Recommendation, the SDT considers this compelling evidence that the paradigm for thinking about generator interconnection Facilities is shifting.

All of this has led the SDT to its current conclusions to modify FAC-001, FAC-003, and PRC-004 and later, PRC-005. The SDT does not believe any further modifications to standards are necessary to maintain an appropriate level of reliability based on the revised assumption that while generator Facilities (at 100 kV and above) will be considered by some to be transmission, Generator Owners and Generator Operators should not be registered as Transmission Owners and Transmission Operators simply as a result of the ownership and operation of such Facilities. Because the majority of commenters support the SDT's current recommendation to not adopt new terms, the SDT has elected to focus on its standard changes and not, at this time, propose revisions to existing, or creation of new, glossary terms.

Below, the SDT discusses the changes it has proposed for FAC-001, FAC-003, and PRC-004 and the changes it plans to propose for PRC-005 and then provides justification for not modifying any of the additional standards and requirements it has reviewed.

## Review of SDT's Proposed Standard Changes

### ***FAC-001-1—Facility Connection Requirements***

While some stakeholders have questioned the modifications in the proposed FAC-001-1, the SDT remains convinced that there is the potential for a reliability gap if this standard is not modified so that it applies to a Generator Owner *if and when it executes an Agreement* to evaluate the reliability impact of interconnecting a third party Facility to its existing generation interconnection Facility. The intent of this modified language is to start the compliance clock when the Generator Owner executes an Agreement to perform the reliability assessment required in FAC-002-1. This step is expected to occur if a Generator Owner is compelled by a regulatory body to allow such interconnection. Assuming that a regulatory body would require a Generator Owner to evaluate such an interconnection request, the SDT expects the Generator Owner and the third party to execute some form of an Agreement. The SDT intentionally excluded a specific reference to the form of Agreement (such as a feasibility study) in deference to stakeholder suggestions to avoid comingling of commercial and reliability issues in reliability standards.

The SDT acknowledges that the scenario described in the proposed FAC-001-1 may be rare, but in the past (for instance, FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities, and the SDT thinks it is important to clarify the responsibilities related to such a request in NERC's Reliability Standards. And, while the SDT acknowledges that such regulatory action might also result in the Generator Owner being registered for other functions, such as Transmission Owner, Transmission Planner, and/or Transmission Service Provider, it decided the proposed revision provides appropriate reliability coverage until any additional registration is required and does not impact any Generator Owner that never executes an Agreement as described in the standard.

### ***FAC-003-X and FAC-003-3—Vegetation Management***

The SDT and most stakeholders agree with the Ad Hoc Group recommendation that FAC-003 be applicable to Generator Owners that own a generation interconnection Facility if that Facility contains overhead conductors. The Ad Hoc Group originally excluded such a Facility from this requirement if its length is less than two spans (generally one half mile from the generator property line). The SDT agrees with that intended exclusion in principle; as it discusses in the document titled "[Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface](#)," the SDT recognizes that in many cases, generation Facilities are (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale for exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit.

Thus, the SDT has maintained this exception language but has modified it based on stakeholder input such that it excludes Facilities shorter than one mile which have a clear line of sight from the fenced area of the generating switchyard to the point of interconnection. Specifically, sections 4.3.1 of both versions of FAC-003 (which address applicable generation Facilities) now state: "Overhead transmission



lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...” The SDT took into consideration all comments submitted in both formal comment periods, and believes that this exemption now adequately addresses the reliability impact for a majority of the Facilities, while balancing the efforts necessary to support the standard from all entities.

#### ***PRC-004-2.1—Analysis and Mitigation of Transmission and Generation Protection System Misoperations***

After examining all standards it had previously reviewed, the SDT elected to propose a slight change to PRC-004-2.1. While the SDT rejected other opportunities to “drop” the phrase “generator interconnection Facility” into requirements because it is not typically the best way to add clarity, in the case of PRC-004-2, the SDT fears that the phrasing of R2 (“The Generator Owner shall analyze its generator Protection System Misoperations...”) could lead to some confusion about whether an interconnection Facility is included. Thus, the SDT proposes adding “and generator interconnection Facility” as redlined in the draft standard. Because there is no change in applicability, and because the SDT believes that most Generator Owners already interpret the standard in this manner, we consider this to be a minor and not substantive change employed only to add clarity.

#### ***PRC-005-1a—Transmission and Generation Protection System Maintenance and Testing***

In the concurrent 45-day comment and ballot period that ended in November 2011, several commenters pointed out that the wording in R1 and R2 of PRC-005-1a requires the same explicit reference to a generator interconnection Facility that was added in PRC-004-2.1 R2. The SDT agrees and is developing revisions to PRC-005-1a. These will be posted (separate from the recirculation ballot posting) soon.

#### **Review of Other Standards Considered by the Standard Drafting Team**

To ensure that no reliability gaps were left when the SDT shifted its strategy from the original strategy of the Ad Hoc Group, the SDT reviewed all standards for which the Ad Hoc Group had proposed changes, and again discussed whether making these standards applicable to Generator Owners or Generator Operators would increase reliability with respect to generator requirements at the transmission interface. During the 45-day concurrent comment and ballot period that ended in November 2011, the SDT also received comments from NERC staff encouraging it to review additional standards that NERC staff had proposed to apply to Generator Owners and Generator Operators in [NERC Compliance Process Directive #2011-CAG-001 Regarding Generator Transmission Leads](#) (Directive). Similarly, stakeholder commenters encouraged the SDT to review standards cited in FERC’s Order Denying Compliance Registry Appeals of Cedar Creek Wind Energy and Milford Wind Corridor Phase I (135 FERC ¶ 61,241) (FERC Order).



The SDT reviewed all of these standards and requirements again and continues to find clear and technical reliability-based reasons that support not adding Generator Owner and Generator Operator requirements to the standards. The chart below indicates where else (the Ad Hoc Report, the NERC Directive, or the FERC Order) the standards addressed were discussed. While both the NERC Directive and FERC Orders address specific requirements within these standards, the SDT has found it useful to address each standard as a whole. Often, requirements within a standard, or even from standard to standard, work in concert to ensure that there are no reliability gaps, whereas a review of a requirement in isolation might give the impression that there is gap.

Standard	Ad Hoc Report*	NERC Directive	FERC Order
EOP-003-1	X		
EOP-005-1		X	
FAC-001-0		X	
FAC-003-1 or FAC-003-2	X	X	X
FAC-014-2		X	X
IRO-005-2	X		
PER-001-0	X		
PER-002-0	X	X	
PER-003-1			X
PRC-001-1		X	X
TOP-001-1	X	X	X
TOP-004-2	X	X	X
TOP-006-1		X	
TOP-008-1	X		

\*This chart and accompanying document only address those standards in the Ad Hoc Report for which substantive changes (change in applicability or the addition of a new requirement) were proposed.

The SDT acknowledges that both NERC and FERC have stated that neither the NERC Directive nor the FERC Order is intended to prejudge the work of the SDT. The SDT also acknowledges that the discussion in the FERC Order is related to specific cases in which certain entities will actually be registered as Transmission Owners and Transmission Operators, a process that is distinct from the SDT’s work, which assumes that once this project is complete, Generator Owners and Generator Operators will not be registered for any other functions based on ownership of a sole-use generator interconnection Facility. Still, because these related efforts are ongoing, the SDT thought it would be useful to directly address some of the discussion in the Directive and the Order. The rest of this document provides the SDT’s technical justification for limiting the scope of its work to FAC-001, FAC-003, PRC-004, and PRC-005.

***EOP-003-1—Load Shedding Plans (addressed in the Ad Hoc Report)***

For EOP-003-1, the Ad Hoc Group originally proposed that Generator Operators be added to the requirement that requires Transmission Operators and Balancing Authorities to coordinate automatic load-shedding throughout their areas. The SDT determined that this addition was unnecessary because PRC-001 already includes the requirement that Transmission Operators coordinate their underfrequency load shedding programs with underfrequency isolation of generating units, which implies that Generator Operators need to provide their underfrequency settings to their respective Transmission Operator. Further, Generator Operators typically do not have the technical expertise or access to the data necessary for the high-level coordination that this standard requires.

***EOP-005-1—System Restoration Plans (addressed in the NERC Directive)***

In its Directive, NERC staff states the following by way of rationale for applying EOP-005-1 Requirements R1, R2, R5, R6, and R7 to Generator Operators:

“If GOP has blackstart capability, then EOP-005 applies, GOP restoration plan would require coordination with TOP per the TOP Blackstart Restoration Plan. The GOP would start its blackstart resources to provide necessary real and reactive power to its generating resources per interconnecting TOP directives. In addition, if GOP has blackstart capability the interconnection TOP will have included this capability in its restoration planning for its area of responsibility. If GOP does not have blackstart capability, GOP restoration plan is dependent upon provision of real and reactive power service from interconnecting TOP, per VAR-001 and VAR-002 requiring the GOP to follow the directives of the interconnecting TOP, compliance with this standard/requirements is not required.”

Blackstart capability of a generating unit is unrelated to owning or operating transmission Facilities or a generation interconnection Facility. During a system restoration event, Generator Operators provide real and reactive power to the BES only at the direction of a Transmission Operator. The Generator Operators are not providing Transmission Operator services through their blackstart Facilities. In addition, many units with blackstart capability are not included in a TOP System Restoration Plan.

In FERC Order 693, paragraph 630, FERC approved EOP-005-1 and found the standard “adequately addresses operating personnel training and system restoration plans to ensure that transmission operators, balancing authorities and reliability coordinators are prepared to restore the Interconnection following a blackout. Accordingly, the Commission approves Reliability Standard EOP-005-1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP-005-1 through the Reliability Standards development process that identifies time frames for training and review of restoration plan requirements.”

FERC also specifically addressed system restoration training concerns and requirements in FERC Order 693 in its review and approval of Reliability Standard EOP-005-1. In that order, FERC stated that

personnel outside a control room should be trained in system restoration, but also that this should be included in a system restoration Reliability Standard, as follows:

627. With regard to comments that the Commission's concerns are being addressed in NERC's drafting of proposed PER-005-1 Reliability Standard on operator training, we note PER-005-1 only includes Requirements on the control room personnel and not those outside of the control room. System restoration requires the participation of not only control room personnel but also those outside of the control room. These include blackstart unit operators and field switching operators in situations where SCADA capability is unavailable. As such, the Commission believes that inclusion of periodic system restoration drills and training and review of restoration plans in a system restoration Reliability Standard is the most effective way of achieving the desired goal of ensuring that all participants are trained in system restoration and that the restoration plans are up to date to deal with system changes.

Thus, FERC clearly found that the existing standard EOP-005-1 adequately addressed operating personnel training and would ensure the restoration of the BES in the event of a blackstart, and further directed that any modifications be addressed through the Reliability Standard Development Process.

Pursuant to Order 693, NERC initiated Project 2006-03, and empowered the System Restoration and Blackstart Standard Drafting Team (SRBSDT) to modify the related standards. The SRBSDT developed Reliability Standard EOP-005-2, which includes Generator Operator system restoration requirements including training, restoration plans, drills, and testing of blackstart resources. In Order 749, FERC approved EOP-005-2, which included its approval of the implementation plan for EOP-005-2. Again, both FERC and NERC had the opportunity to identify issues with the implementation time of EOP-005-2 and declined to do so.

5. Currently effective Reliability Standard EOP-005-1 requires transmission operators, balancing authorities, and reliability coordinators to have a restoration plan, test the plan, train operating personnel in the restoration plan, and have the ability to restore the Interconnection using the plans following a blackout. In Order No. 693, the Commission directed the ERO to develop, through the Reliability Standard development process, a modification to EOP-005-1 that identifies time frames for training and review of restoration plan requirements to simulate contingencies and prepare operators for anticipated and unforeseen events . . .

Also, in FERC Order 749, both NERC and FERC identified the modifications to EOP-005 as "improvements" to the standard, not changes to close a reliability gap:

10. NERC states that the proposed Reliability Standards "represent significant revision and improvement from the current set of enforceable standards" and address the Commission's directives in Order No. 693 related to the EOP standards. NERC explains that, among other

enhancements, “[t]he proposed revisions now clearly delineate the responsibilities of the Reliability Coordinator and Transmission Operator in the restoration process and restoration planning.” NERC describes the proposed Reliability Standards as providing “specific requirements for what must be in a restoration plan, how and when it needs to be updated and approved, what needs to be provided to operators and what training is necessary for personnel involved in restoration processes.

17. . . . By enhancing the rigor of the restoration planning process, the Reliability Standards represent an improvement from the current Standards and will improve the reliability of the Bulk-Power System. . . .

In summary, the Generator Operator blackstart requirements have been already been appropriately addressed through the Reliability Standards Development Process. EOP-005-2 will become effective in 2013 as approved by both the NERC Board of Trustees and FERC. There is no existing reliability gap related to owning a generation interconnection Facility and Standard EOP-005-1.

***FAC-014-2—Establish and Communicate System Operating Limits (addressed in the NERC Directive and the FERC Order)***

FAC-014-2, R2 states “The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator’s SOL Methodology.”

In its Directive, NERC states, with respect to FAC-014-2: “In the event an RC directs the establishment of an SOL, the SOL must be established in accordance with the RC’s SOL Methodology.”

In paragraphs 68 and 84 of the FERC Order, FERC states that without compliance with FAC-014, R2, the entity in questions could “avoid establishing the system operating limit for its line or be allowed to establish an operating limit for its line that is not consistent with the requirements of the reliability coordinator’s methodology.”

The SDT does not believe that FAC-014-2 R2 should be revised to include Generator Operators. The Generator Owner is required by the FERC-approved versions of FAC-008-1 R1 and FAC-009-1 and pending FAC-008-3 R1, R2, and R6 (which has been filed for approval with FERC) to document the Facility Ratings for a Generator Owner-owned generator interconnection circuit greater than 100kV. The established Facility Rating must respect the most limiting applicable equipment rating in the circuit and must consider operating limitations and ambient conditions. The thermal or ampere rating of this circuit would equal its ampere operating limit and should be conveyed by the Generator Owner to the Generator Operator if they are not the same entity. The operating voltage limits for this circuit are established by the applicable Transmission Owner or Transmission Operator, not the Generator Owner or Generator Operator.

Therefore, we believe adding the Generator Owner to FAC-014-2 R2 would be redundant. What's more, the SDT is concerned that entities with a limited view of the system should not be setting IROLs or SOLs. We believe this should be the responsibility of entities with a wide-area view, as shown in the standard today; otherwise, we are concerned that reliability may be jeopardized. Commenters – including one from the Transmission Owner segment – have offered this same justification.

***IRO-005-2—Reliability Coordination – Current Day Operations (addressed in the Ad Hoc Report)***

The SDT chose not to adopt the revision to IRO-005-2 proposed by the Ad Hoc Group. This revision would have added a new requirement that would read, “The Generator Operator shall immediately inform the Transmission Operator of the status of the Special Protection System, including any degradation or potential failure to operate as expected for SPS relay or control equipment under its control.” The SDT initially determined that IRO-005-2 did not require modification because of the October 2011 retirement of the standard. In subsequent meetings, the SDT also reached the conclusion that there is no reliability gap as PRC-001-1 R2 already requires the Generator Operator to notify reliability entities of relay or equipment failures. The SDT believes that a Special Protection System is a form of protection system and therefore any degradation or potential failure to operate as expected would be required to be reported by the Generator Operator to reliability entities (Balancing Authorities, Transmission Operators, and Reliability Coordinators).

***PER Standards (PER-001-0 and PER-002-0 were addressed in the Ad Hoc Report; PER-002-0 was addressed in the NERC Directive; and PER-003-1 was addressed in the FERC Order)***

The Ad Hoc Group had proposed changes to PER-001-0—Operating Personnel Responsibility and Authority and PER-002-0—Operating Personnel Training. For PER-001-0, the Ad Hoc Group proposed adding a new R2 that would read “Each Generator Operator shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Generation Facility and Generation Interconnection Facility, and the responsibility and authority to follow the directives of reliability authorities including the Transmission Operator and Balancing Authority.” To PER-002-0, the Ad Hoc Group proposed adding the Generator Operator to R1 (“Each Transmission Operator, Generator Operator, and Balancing Authority shall be staffed with adequately trained operating personnel”) and adding a new R3 that would read: “Each Generator Operator shall implement an initial and continuing training program for all operating personnel that are responsible for operating the Generator Interconnection Facility that verifies the personnel’s ability and understanding to operate the equipment in a reliable manner.”

In its Directive, NERC does not address PER-001-0, but it states the following with respect to PER-002-0:

“The registered entity will develop an appropriate training program that contains the necessary elements for the GO/GOP operating a transmission facility to understand fully the impacts of the operation on the BPS, such as equipment involved, including protection systems, the

coordination aspects with the TO/TOP to which it is connected, and the protocols for and impacts of operating facilities associated with the transmission facility. The objective of this training is to ensure that the GO/GOP is completely aware of its obligations to follow the directives of the appropriate TOP and has personnel with the skills and training to execute these obligations in the best interest of reliability.”

These proposed changes to the PER standards have little to do with responsibilities that relate specifically to a generator interconnection Facility. Issues related to the training of Generator Operators existed separately from the work of Project 2010-07, and the SDT agrees that its scope limits its efforts to standards that are directly related to generator requirements at the transmission interface. The SDT also cites past FERC Orders as proof that this issue is not within the scope of Project 2010-07. In Order 693, FERC directed NERC to "expand the applicability of the personnel training Reliability Standard, PER-002-0, to include (i) generator operators centrally-located at a generation control center with a direct impact on the reliable operation of the Bulk-Power System..." In Order 742, FERC reaffirmed this, stating that it is "not modifying the Order No. 693 directive regarding training for certain generator operator dispatch personnel, nor are we expanding a generator operator's responsibilities.”

Centrally-located generator operators working at a generation control center typically dispatch the output from multiple generating units. As such, they can be called upon to comply with orders from their Balancing Authority that may have a significant impact on the reliable operation of the BES. Their training would be covered by proposed changes to PER-002-0 and Order 742. Generator Operators who deal with interconnection Facilities at individual generating plants, on the other hand, typically do not receive reliability-based orders specific to the interconnection Facilities and are therefore not covered by Order 742. Further, the SDT believes there is no reliability gap as TOP-001-1 R3 already requires Generator Operators to follow the directives of the appropriate Transmission Operators.

These training-related items are clearly important ones for the Commission, but the SDT does not think it is appropriate to fold modifications to these PER standards into the scope of its work unless it is specifically directed to do so. For now, modifications to PER-002-0 based on Order 693 directives are already included in [NERC's Issue Database](#) (P. 52-53) to be addressed by a future project. PER-001-0 is not addressed in the Issues Database, but the [Project 2007-03 drafting team has proposed](#) that the standard be retired.

The FERC Order does not address PER-001-0 or PER-002-0, but it does address PER-003-1. In paragraphs 67 and 81 of the FERC Order, FERC expresses concern that operational control over the transmission line breakers owned by the entities in question are not under the control of NERC certified operators. FERC goes on to say that “Reliability Standard PER-003-001 requires NERC certification of all operators that have responsibility for the real-time operation of the interconnected Bulk Electric System. When switching the tie-line in or out of service, operators must have the

appropriate credentials and training to properly perform the switching and coordinate the switching to prevent adverse impacts such as the introduction of faults on the system.”

The SDT can find no evidence that the kinds of training requirements for operating the breakers of the generator interconnection Facility cited in the FERC Order exist elsewhere for other entities that operate breakers on lines. For instance, Transmission Owners that are not also Transmission Operators are not required to undergo any sort of training. The SDT does not mean to dismiss this issue altogether, and it may be that training should be expanded to include Generator Owners, Generator Operators, Transmission Owners, end users, and possibly others, but the development of such requirements would have implications far beyond the scope and expertise of this team.

***PRC-001-1—System Protection Coordination (addressed in the NERC Directive and the FERC Order)***

The NERC Directive addresses PRC-001-1 R2, R2.2, and R4. The FERC Order addresses these requirements, along with Requirement R6.

About R2 and R4, NERC’s Directive simply states: “PRC-001-R2 requires notification and corrective action for relay or equipment failure. R4 coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.”

In paragraphs 64 and 78 of the FERC Order, FERC expresses concern that “there is a risk of an adverse impact on reliability if the protection relays or protection systems on the [entity’s] line are not coordinated with those on the transmission network facilities in its area.”

Generator Operators and the scope of protection equipment for generation interconnection Facilities are already appropriately accounted for in this standard in requirement R2 and sub-requirement R2.2. The language used in R2 that applies to the Generator Operator uses the general terms “relay or equipment failures” which would include not only generator relaying, but generator interconnection relaying in the Generator Operator’s scope as well. The Generator Operator is required to notify the Transmission Operator and Host Balancing Authority in R2.1 “if a protective relay or equipment failure reduces system reliability.” Requirement R2.2 requires the affected Transmission Operator to notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. Thus, applying R2.2 to a Generator Operator would be redundant to R2.1. If a Generator Operator had a relay or equipment failure on its Facility, including its interconnection Facility it would be required to report that to its Transmission Operator under R2.1, and the Transmission Operator is then required to notify its Reliability Coordinator and other affected Transmission Operators and Balancing Authorities under R2.2.

PRC-001-1 R4 states, “Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission



Operators, and Balancing Authorities.” A sole-use generator interconnection Facility does not constitute a major transmission line or major interconnection with neighboring Generator Operators, Transmission Operators, and Balancing Authorities. Thus, R4 should not be revised to include Generator Operators. In general, any coordination that might be required is covered by the fact that the Transmission Operator that is connected to a major transmission lines or interconnection has the requirement to coordinate protection on the interconnection, and there is no reliability gap.

PRC-001-1 R6 states, “Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.” It is clearly the responsibility of the Transmission Operator and/or Balancing Authority to monitor the Special Protection System, as they are the entity with a wide-area view, not the responsibility of a Generator Owner/Generator Operator with a local-area view who happens to have generator interconnection Facilities in the area. The requirement focuses on the Transmission Operator and Balancing Authority monitoring the status of each Special Protection System *in their area*; there is no “area” for the Generator Operator to monitor. For these reasons, there is no need to make this requirement applicable to Generator Operators.

***TOP-001-1—Reliability Responsibilities and Authority (addressed in the Ad Hoc Report, NERC Directive, and FERC Order)***

Both the NERC Directive and the FERC Order discuss making TOP-001-1 R1 applicable to Generator Operators. About TOP-001-1, the NERC Directive simply states: “TOP-001-1 R1 ensures personnel assigned to operate BES transmission facilities have clear and unambiguous authority to operate those facilities.” With respect to R1, paragraphs 68 and 83 of FERC’s Order focus on ensuring that “system operators have the authority to take actions to maintain Bulk-Power System facilities within operating limits.”

TOP-001-1 R1 states, “Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.” TOP-001-1 R3 appropriately requires the GOP to comply with reliability directives issued by the Transmission Operator “unless such actions would violate safety, equipment, regulatory or statutory requirements.” These requirements effectively give the Transmission Operator the necessary decision-making authority over operation of all generator Facilities up to the point of interconnection. Thus, no changes to TOP-001-1 are necessary.

Additionally, the Ad Hoc Group proposed adding two new requirements to TOP-001-1. The first was proposed as R9 and read: “The Generator Operator shall coordinate the operation of its Generator Interconnection Facility with the Transmission Operator to whom it interconnects in order to preserve Interconnection reliability...” The SDT does not agree that TOP-001-1 needs to apply to Generator Operators in any form. TOP-002-2 R3 (proposed to be covered in the future by TOP-003-2, as outlined



in Project 2007-03's Implementation Plan) already requires the Generator Operator to coordinate its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. These entities are, in turn, required to coordinate with their respective Transmission Operator. Additionally, TOP-002-2 R4 (proposed to be covered in the future by TOP-003-2, as outlined in Project 2007-03's Implementation Plan) requires each Balancing Authority and Transmission Operator to coordinate with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator. With these requirements, Generator Operators are already required to provide necessary operations information to Transmission Operators. To require the same thing in TOP-001-1 would be redundant.

The second new requirement proposed by the Ad Hoc Group for TOP-001-1 was R10, which was to read: "The Transmission Operator shall have decision-making authority over operation of the Generator Interconnection Operational Interface at all times in order to preserve Interconnection reliability." As cited above, TOP-002-2 R3 (proposed to be covered in the future by TOP-003-2, as outlined in Project 2007-03's Implementation Plan) already requires the Generator Operator to coordinate with its interconnecting Transmission Operator. Further, TOP-001-1 R3 (proposed to be covered in the future in the proposed IRO-001-2 R2 and R3) already requires the Generator Operator to comply with reliability directives issued by the Transmission Operator. These requirements effectively give the Transmission Operator decision-making authority over operation of all generator Facilities up to the point of interconnection. To require the same thing in TOP-001-1 would be redundant.

***TOP-004-2—Transmission Operations (addressed in the NERC Directive and the FERC Order)***

Both the NERC Directive and the FERC Order address the application of TOP-004-2 R6 to Generator Operators. In its Directive, NERC simply states: "TOP-004-2 R6 ensures formal policies and procedures are formulated to provide for coordination of activities that may impact reliability." In paragraphs 67 and 82 of the FERC Order, FERC talks about entities ensuring the development of coordination protection to coordinate switching a generator interconnection Facility in and out of service, since different entities have control over different ends of the line. FERC concludes that for the entities in question, TOP-004-2 R6 must apply.

Requirement R6 and its sub-requirements state: "R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: R6.1. Monitoring and controlling voltage levels and real and reactive power flows, R6.2. Switching transmission elements, R6.3. Planned outages of transmission elements, R6.4. Responding to IROL and SOL violations."

TOP-001-1 R3 appropriately requires the Generator Operator to comply with reliability directives issued by the Transmission Operator. These requirements give the Transmission Operator the necessary decision-making authority over operation of all generator Facilities, including interconnection Facilities, up to the point of interconnection. Further, TOP-002-2 R3 requires the Generator Owner to coordinate its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. These entities are, in turn, required to coordinate with their respective Transmission Operators (also in TOP-002-2 R3). Each Balancing Authority and Transmission Operator is also then required to coordinate with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator (in TOP-002-2 R4). The coordination with which NERC and FERC are concerned is already addressed by these other requirements.

The Ad Hoc Group had proposed a new requirement, R7, for TOP-004-2 that would read: “The Generator Operator shall operate its Generator Interconnection Facility within its applicable ratings.” The SDT does not agree that a reliability gap exists, because an operator has a fiduciary obligation to protect a Facility for which it is operationally responsible. FAC-008-1—Facility Ratings Methodology and FAC-009-1—Establish and Communicate Facility Ratings already infer that the reason for establishing a ratings methodology and communicating Facility Ratings to the Reliability Coordinator, Planning Authority, Transmission Planner, and Transmission Operator is “...for use in reliable planning and operation of the Bulk Electric System.” Further, TOP-004-2 is proposed to be retired under the work of the Project 2007-03 drafting team. Its requirements will either be deleted or assigned elsewhere.

***TOP-006-1—Monitoring System Conditions (addressed in the NERC Directive; the SDT believes NERC intended to refer to TOP-006-2)***

Only the NERC Directive addresses TOP-006. It states: “TOP-006-1 R3 ensures technical information is provided to the responsible personnel; R6 ensures correct and accurate data to TOP and BA.” But PRC-001-1 R1 (“Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area”) addresses the necessary Generator Operator requirements with respect to TOP-006-2 R3. The SDT believes that knowledge of the purpose and limitations of protection system schemes applied in its area (required in PRC-001-1 R1) constitutes knowledge of “the appropriate technical information concerning protective relays” (required in TOP-006-1 R3).

TOP-006-2 R6 states “Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.” FAC-001-1 R2.1.6 already requires the Transmission Owner’s facility connection requirements to address “metering and telecommunications.” Any generator Facility that interconnected with a Transmission Owner would

have had to meet their Facility connection and system performance requirements for metering and telecommunications. Thus, there is no reliability gap.

***TOP-008-1—Response to Transmission Limit Violations (addressed in the Ad Hoc Report)***

Only the Ad Hoc Report addressed TOP-008-1, and it proposed a new requirement, R5, to TOP-008-1—Response to Transmission Limit Violations that would read “The Generator Operator shall disconnect the Generator Interconnection Facility when safety is jeopardized or the overload or abnormal voltage or reactive condition persists and generating equipment or the Generator Interconnection Facility is endangered. In doing so, the Generator Operator shall notify its Transmission Operator and Balancing Authority impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.” The SDT sees no reliability benefit to adding this requirement. TOP-001-1 R7 (“Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless...”) and its parts give the Generator Operator authority over its Facilities, which would include the generator interconnection Facility. If there is an outage, R7.1 requires the Generator Operator to notify and coordinate with its Transmission Operator, which is required to notify the Reliability Coordinator and other affected Transmission Operators. And as with TOP-004-2, the Project 2007-03 drafting team has proposed to delete all of TOP-008-1’s requirements and retiring the standard.

**Conclusion**

The Project 2010-07 SDT is confident that the changes it has proposed address the reliability gap that exists with respect to the responsibilities of Generator Owners and Generator Operations that own sole-use interconnection Facilities. The changes to FAC-001, FAC-003, and PRC-004 have been supported by stakeholders during comment periods, and there has been no strong support of technical justification provided for bringing other standards into the scope of this project.

# Technical Justification Resource Document

Project 2010-07 Generator Requirements at the Transmission Interface

## Background

As part of its work on Project 2010-07—Generator Requirements at the Transmission Interface, the standard drafting team (SDT) reviewed 34 reliability standards and 102 requirements to determine what changes are necessary to close a reliability gap with respect to what is commonly known as the generator interconnection Facility. ~~The majority~~ Many of these standards and requirements had been addressed in the [Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface](#) (Ad Hoc Report), and additional standards ~~have been~~ were reviewed, ~~and will continue to be reviewed,~~ as a result of informal discussions with NERC and FERC staffs.

The basis for standard modifications recommended by the Ad Hoc Group for Generator Requirements at the Transmission Interface (Ad Hoc Group) was a few fundamental clarifications to the definitions of Generator Owner, Generator Operator, and Transmission, along with the creation of new definitions: one for Generator Interconnection Facility and one for Generator Interconnection Operational Interface. The Ad Hoc Group proposed the addition of these two new definitions to 26 standards encompassing 29 requirements (new and old), along with some modifications to FAC-003 to make it applicable to Generator Owners under certain circumstances.

Since the publication of the Ad Hoc Report, various entities have challenged these modifications and the recommended creation of the new definitions. The SDT has developed a more focused approach than that of the Ad Hoc Group: to propose recommendations whereby ~~radial~~ sole-use interconnection Facilities (at or above 100 kV) that are owned and operated by generating entities will be included in a small set of standards and requirements previously only applicable to Transmission Owners. The SDT agrees completely with the Ad Hoc Group's conclusion that Generator Owners and Operators of these ~~radial~~ sole-use generator tie-line Facilities (at voltages equal to or greater than 100 kV) should not be registered as Transmission Owners and Transmission Operators in order to maintain reliability on the Bulk Electric System (BES).

The SDT's justification for this strategy is rooted in the very title of its standards project: "Generator Requirements at the Transmission Interface." That is, the goal and scope of the project has always been to determine the responsibilities of those Generator Owners and Generator Operators that own or operate an interconnection Facility (in some cases labeled a "transmission Facility") between the generator and the interface with the portion of the BES where Transmission Owners and Transmission Operators take over ownership and operating responsibility. These kinds of Generator Owners and Generator Operators do not own or operate Facilities that are part of the interconnected system; rather, they own and operate ~~radial~~ sole-use Facilities that are connected to the boundary of the

interconnected system and as such have a limited role in providing reliability compared to those that operate in a networked fashion beyond the point of interconnection.

While some argue that these interconnecting portions of a Generator Owner's Facilities could be defined as Transmission and thus require the Generator Owner and Generator Operator for the Facility to be classified and registered as a Transmission Owner and Transmission Operator, the SDT does not believe this is necessary to provide an appropriate level of reliability for the BES. Just as important, such classification and registration could actually cause a reduction in reliability. Generator Owners and Generator Operators do not need, and in some cases may be prohibited from having, a wide-area view and responsibility for the integrated transmission system. Requiring Generator Owners and Generator Operators to have such responsibilities would require significant training, ~~would~~ require substantially more data and modeling responsibilities, and ~~would~~ detract from the entities' primary functions: to own and operate their generation equipment – including any Facilities owned and operated at voltages of 100 kV or greater that connect to the interconnected system – in a reliable manner.

Additionally, the SDT believes that the industry is much more aware today of the need to include *all* elements (owned and operated at 100 kV or higher) of a generator Facility in the procedures and compliance program of the registered entity that owns or has operational responsibility of those elements. Industry awareness was raised substantially at the time the [October 17, 2010 Facility Ratings Recommendation to Industry](#) was issued (which included Generator Owners and specifically addressed interconnection Facilities in [the Q&A document](#)); ~~with the statement that the alert applied to generator interconnection tie lines that are radial only and do not serve load "if the generator is considered part of the bulk electric system"~~. While this applies to a specific NERC Recommendation, the SDT considers this compelling evidence that the paradigm for thinking about generator interconnection Facilities is shifting.

All of this has led the SDT to its current conclusions to modify FAC-001, FAC-003, and PRC-004; ~~and later, PRC-005~~. The SDT does not believe any further modifications to standards are necessary to maintain an appropriate level of reliability based on the revised assumption that while generator Facilities (at 100 kV and above) will be considered by some to be transmission, Generator Owners and Generator Operators should not be registered as Transmission Owners and Transmission Operators simply as a result of the ownership and operation of such Facilities. Because the majority of commenters support the SDT's current recommendation to not adopt new terms, the SDT has elected to focus on its standard changes and ~~to postpone discussions on not, at this time, propose~~ revisions to existing, or creation of new, ~~definitions until the standards have been successfully balloted.~~ [glossary terms](#).

Below, the SDT discusses the changes it has proposed for FAC-001, FAC-003, and PRC-004 and [the changes it plans to propose for PRC-005 and](#) then provides justification for not modifying any [of the](#)

additional standards ~~that had been proposed for substantive modification in the Ad Hoc Report and requirements it has reviewed.~~

## Review of SDT's Proposed Standard Changes

### ***FAC-001-1—Facility Connection Requirements***

While some stakeholders have questioned the modifications in the proposed FAC-001-1, the SDT remains convinced that there is the potential for a reliability gap if this standard is not modified so that it applies to a Generator Owner *if and when it executes an Agreement* to evaluate the reliability impact of interconnecting a third party Facility to its existing generation interconnection Facility. The intent of this modified language is to start the compliance clock when the Generator Owner executes an Agreement to perform the reliability assessment required in FAC-002-1. This step is expected to occur if a Generator Owner is compelled by a regulatory body to allow such interconnection. Assuming that a regulatory body would require a Generator Owner to evaluate such an interconnection request, the SDT expects the Generator Owner and the third party to execute some form of an Agreement. The SDT intentionally excluded a specific reference to the form of Agreement (such as a feasibility study) in deference to stakeholder suggestions to avoid comingling of commercial and reliability issues in reliability standards.

The SDT acknowledges that the scenario described in the proposed FAC-001-1 may be rare, but in the past (for instance, FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities, and the SDT thinks it is important to clarify the responsibilities related to such a request in NERC's Reliability Standards. And, while the SDT acknowledges that such regulatory action might also result in the Generator Owner being registered for other functions, such as Transmission Owner, Transmission Planner, and/or Transmission Service Provider, it decided the proposed revision provides appropriate reliability coverage until any additional registration is required and does not impact any Generator Owner that never executes an Agreement as described in the standard.

### ***FAC-003-X and FAC-003-3—Vegetation Management***

The SDT and most stakeholders agree with the Ad Hoc Group recommendation that FAC-003 be applicable to Generator Owners that own a generation interconnection Facility if that Facility contains overhead conductors. The Ad Hoc Group originally excluded such a Facility from this requirement if its length is less than two spans (generally one half mile from the generator property line). ~~After reviewing formal comments, the The SDT agreed to revise the agrees with that intended exclusion so that it applies to a Facility if its length is "one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard" to approximate line of sign from a fixed point. Other than revising this exclusion, in principle; as it discusses in the document titled "Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface," the SDT applied the same criteria to the Generator Owner as applies to the Transmission Owner in the current FERC approved version of this standard as well as one approved by stakeholders (under Project 2007-07) in February 2011. The SDT is~~



communicating with NERC staff recognizes that in many cases, generation Facilities are (1) staffed and the Project 2007-07 SDT to ensure that changes to this standard will be coordinated before submitting to NERC's Board of Trustees, but feels compelled to continue to posting both versions until the outcome of Project 2007-07 efforts is clearer overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale for exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit.

Thus, the SDT has maintained this exception language but has modified it based on stakeholder input such that it excludes Facilities shorter than one mile which have a clear line of sight from the fenced area of the generating switchyard to the point of interconnection. Specifically, sections 4.3.1 of both versions of FAC-003 (which address applicable generation Facilities) now state: "Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are..." The SDT took into consideration all comments submitted in both formal comment periods, and believes that this exemption now adequately addresses the reliability impact for a majority of the Facilities, while balancing the efforts necessary to support the standard from all entities.

#### ***PRC-004-2.1—Analysis and Mitigation of Transmission and Generation Protection System Misoperations***

After examining all standards it had previously reviewed, the SDT elected to propose a slight change to PRC-004-2.1. While the SDT rejected other opportunities to "drop" the phrase "generator interconnection Facility" into requirements because it is not typically the best way to add clarity, in the case of PRC-004-2, the SDT fears that the phrasing of R2 ("The Generator Owner shall analyze its generator Protection System Misoperations...") could lead to some confusion about whether an interconnection Facility is included. Thus, the SDT proposes adding "and generator interconnection Facility" as redlined in the draft standard. Because there is no change in applicability, and because the SDT believes that most Generator Owners already interpret the standard in this manner, we consider this to be a minor and not substantive change employed only to add clarity.

#### ***PRC-005-1a—Transmission and Generation Protection System Maintenance and Testing***

In the concurrent 45-day comment and ballot period that ended in November 2011, several commenters pointed out that the wording in R1 and R2 of PRC-005-1a requires the same explicit reference to a generator interconnection Facility that was added in PRC-004-2.1 R2. The SDT agrees and is developing revisions to PRC-005-1a. These will be posted (separate from the recirculation ballot posting) soon.

#### ***Review of Other Substantive Standards Considered by the Standard Modifications from the Ad-Hoc Report Drafting Team***

To ensure that no reliability gaps were left when the SDT shifted its strategy from the original strategy of the Ad Hoc Group, the SDT reviewed all standards for which the Ad Hoc Group had proposed changes, and again discussed whether making these standards applicable to Generator Owners or Generator Operators would increase reliability with respect to generator requirements at the transmission interface. ~~Below, the SDT provides its reasons for not proposing the substantive changes that were included in the Ad Hoc Report (that is, a change in applicability or new requirement, beyond simply adding the text “including its Generator Interconnection Facility” to an existing requirement). As Project 2010-07 continues, the SDT will work with FERC staff, NERC staff, and industry groups to determine if its list of proposed standards is supported industry-wide, and whether other standards need to be considered.~~ During the 45-day concurrent comment and ballot period that ended in November 2011, the SDT also received comments from NERC staff encouraging it to review additional standards that NERC staff had proposed to apply to Generator Owners and Generator Operators in NERC Compliance Process Directive #2011-CAG-001 Regarding Generator Transmission Leads (Directive). Similarly, stakeholder commenters encouraged the SDT to review standards cited in FERC’s Order Denying Compliance Registry Appeals of Cedar Creek Wind Energy and Milford Wind Corridor Phase I (135 FERC ¶ 61,241) (FERC Order).

~~The SDT reviewed all of these standards and requirements again and continues to find clear and technical reliability-based reasons that support not adding Generator Owner and Generator Operator requirements to the standards. The chart below indicates where else (the Ad Hoc Report, the NERC Directive, or the FERC Order) the standards addressed were discussed. While both the NERC Directive and FERC Orders address specific requirements within these standards, the SDT has found it useful to address each standard as a whole. Often, requirements within a standard, or even from standard to standard, work in concert to ensure that there are no reliability gaps, whereas a review of a requirement in isolation might give the impression that there is gap.~~

<u>Standard</u>	<u>Ad Hoc Report*</u>	<u>NERC Directive</u>	<u>FERC Order</u>
<u>EOP-003-1</u>	<u>X</u>		
<u>EOP-005-1</u>		<u>X</u>	
<u>FAC-001-0</u>		<u>X</u>	
<u>FAC-003-1 or FAC-003-2</u>	<u>X</u>	<u>X</u>	<u>X</u>
<u>FAC-014-2</u>		<u>X</u>	<u>X</u>
<u>IRO-005-2</u>	<u>X</u>		
<u>PER-001-0</u>	<u>X</u>		
<u>PER-002-0</u>	<u>X</u>	<u>X</u>	
<u>PER-003-1</u>			<u>X</u>
<u>PRC-001-1</u>		<u>X</u>	<u>X</u>
<u>TOP-001-1</u>	<u>X</u>	<u>X</u>	<u>X</u>
<u>TOP-004-2</u>	<u>X</u>	<u>X</u>	<u>X</u>
<u>TOP-006-1</u>		<u>X</u>	



TOP-008-1	X		
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\*This chart and accompanying document only address those standards in the Ad Hoc Report for which substantive changes (change in applicability or the addition of a new requirement) were proposed.

The SDT acknowledges that both NERC and FERC have stated that neither the NERC Directive nor the FERC Order is intended to prejudge the work of the SDT. The SDT also acknowledges that the discussion in the FERC Order is related to specific cases in which certain entities will actually be registered as Transmission Owners and Transmission Operators, a process that is distinct from the SDT's work, which assumes that once this project is complete, Generator Owners and Generator Operators will not be registered for any other functions based on ownership of a sole-use generator interconnection Facility. Still, because these related efforts are ongoing, the SDT thought it would be useful to directly address some of the discussion in the Directive and the Order. The rest of this document provides the SDT's technical justification for limiting the scope of its work to FAC-001, FAC-003, PRC-004, and PRC-005.

**EOP-003-1—Load Shedding Plans (addressed in the Ad Hoc Report)**

For EOP-003-1, the Ad Hoc Group originally proposed that Generator Operators be added to the requirement that requires Transmission Operators and Balancing Authorities to coordinate automatic load-shedding throughout their areas. The SDT determined that this addition was unnecessary because PRC-001 already includes the requirement that Transmission Operators coordinate their underfrequency load shedding programs with underfrequency isolation of generating units, which inferred implies that Generator Operators need to provide their underfrequency settings to their respective Transmission Operator. Further, Generator Operators typically do not have the technical expertise or access to the data necessary for the high-level coordination that this standard requires.

**EOP-005-1—System Restoration Plans (addressed in the NERC Directive)**

In its Directive, NERC staff states the following by way of rationale for applying EOP-005-1 Requirements R1, R2, R5, R6, and R7 to Generator Operators:

“If GOP has blackstart capability, then EOP-005 applies, GOP restoration plan would require coordination with TOP per the TOP Blackstart Restoration Plan. The GOP would start its blackstart resources to provide necessary real and reactive power to its generating resources per interconnecting TOP directives. In addition, if GOP has blackstart capability the interconnection TOP will have included this capability in its restoration planning for its area of responsibility. If GOP does not have blackstart capability, GOP restoration plan is dependent upon provision of real and reactive power service from interconnecting TOP, per VAR-001 and VAR-002 requiring the GOP to follow the directives of the interconnecting TOP, compliance with this standard/requirements is not required.”

Blackstart capability of a generating unit is unrelated to owning or operating transmission Facilities or a generation interconnection Facility. During a system restoration event, Generator Operators provide real and reactive power to the BES only at the direction of a Transmission Operator. The Generator Operators are not providing Transmission Operator services through their blackstart Facilities. In addition, many units with blackstart capability are not included in a TOP System Restoration Plan.

In FERC Order 693, paragraph 630, FERC approved EOP-005-1 and found the standard “adequately addresses operating personnel training and system restoration plans to ensure that transmission operators, balancing authorities and reliability coordinators are prepared to restore the Interconnection following a blackout. Accordingly, the Commission approves Reliability Standard EOP-005-1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP-005-1 through the Reliability Standards development process that identifies time frames for training and review of restoration plan requirements.”

FERC also specifically addressed system restoration training concerns and requirements in FERC Order 693 in its review and approval of Reliability Standard EOP-005-1. In that order, FERC stated that personnel outside a control room should be trained in system restoration, but also that this should be included in a system restoration Reliability Standard, as follows:

627. With regard to comments that the Commission’s concerns are being addressed in NERC’s drafting of proposed PER-005-1 Reliability Standard on operator training, we note PER-005-1 only includes Requirements on the control room personnel and not those outside of the control room. System restoration requires the participation of not only control room personnel but also those outside of the control room. These include blackstart unit operators and field switching operators in situations where SCADA capability is unavailable. As such, the Commission believes that inclusion of periodic system restoration drills and training and review of restoration plans in a system restoration Reliability Standard is the most effective way of achieving the desired goal of ensuring that all participants are trained in system restoration and that the restoration plans are up to date to deal with system changes.

Thus, FERC clearly found that the existing standard EOP-005-1 adequately addressed operating personnel training and would ensure the restoration of the BES in the event of a blackstart, and further directed that any modifications be addressed through the Reliability Standard Development Process.

Pursuant to Order 693, NERC initiated Project 2006-03, and empowered the System Restoration and Blackstart Standard Drafting Team (SRBSDT) to modify the related standards. The SRBSDT developed Reliability Standard EOP-005-2, which includes Generator Operator system restoration requirements including training, restoration plans, drills, and testing of blackstart resources. In Order 749, FERC approved EOP-005-2, which included its approval of the implementation plan for EOP-005-2. Again,

both FERC and NERC had the opportunity to identify issues with the implementation time of EOP-005-2 and declined to do so.

5. Currently effective Reliability Standard EOP-005-1 requires transmission operators, balancing authorities, and reliability coordinators to have a restoration plan, test the plan, train operating personnel in the restoration plan, and have the ability to restore the Interconnection using the plans following a blackout. In Order No. 693, the Commission directed the ERO to develop, through the Reliability Standard development process, a modification to EOP-005-1 that identifies time frames for training and review of restoration plan requirements to simulate contingencies and prepare operators for anticipated and unforeseen events . . .

Also, in FERC Order 749, both NERC and FERC identified the modifications to EOP-005 as “improvements” to the standard, not changes to close a reliability gap:

10. NERC states that the proposed Reliability Standards “represent significant revision and improvement from the current set of enforceable standards” and address the Commission’s directives in Order No. 693 related to the EOP standards. NERC explains that, among other enhancements, “[t]he proposed revisions now clearly delineate the responsibilities of the Reliability Coordinator and Transmission Operator in the restoration process and restoration planning.” NERC describes the proposed Reliability Standards as providing “specific requirements for what must be in a restoration plan, how and when it needs to be updated and approved, what needs to be provided to operators and what training is necessary for personnel involved in restoration processes.

17. . . . By enhancing the rigor of the restoration planning process, the Reliability Standards represent an improvement from the current Standards and will improve the reliability of the Bulk-Power System. . . .

In summary, the Generator Operator blackstart requirements have been already been appropriately addressed through the Reliability Standards Development Process. EOP-005-2 will become effective in 2013 as approved by both the NERC Board of Trustees and FERC. There is no existing reliability gap related to owning a generation interconnection Facility and Standard EOP-005-1.

**FAC-014-2—Establish and Communicate System Operating Limits (addressed in the NERC Directive and the FERC Order)**

FAC-014-2, R2 states “The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator’s SOL Methodology.”

In its Directive, NERC states, with respect to FAC-014-2: “In the event an RC directs the establishment of an SOL, the SOL must be established in accordance with the RC’s SOL Methodology.”

In paragraphs 68 and 84 of the FERC Order, FERC states that without compliance with FAC-014, R2, the entity in questions could “avoid establishing the system operating limit for its line or be allowed to establish an operating limit for its line that is not consistent with the requirements of the reliability coordinator’s methodology.”

The SDT does not believe that FAC-014-2 R2 should be revised to include Generator Operators. The Generator Owner is required by the FERC-approved versions of FAC-008-1 R1 and FAC-009-1 and pending FAC-008-3 R1, R2, and R6 (which has been filed for approval with FERC) to document the Facility Ratings for a Generator Owner-owned generator interconnection circuit greater than 100kV. The established Facility Rating must respect the most limiting applicable equipment rating in the circuit and must consider operating limitations and ambient conditions. The thermal or ampere rating of this circuit would equal its ampere operating limit and should be conveyed by the Generator Owner to the Generator Operator if they are not the same entity. The operating voltage limits for this circuit are established by the applicable Transmission Owner or Transmission Operator, not the Generator Owner or Generator Operator.

Therefore, we believe adding the Generator Owner to FAC-014-2 R2 would be redundant. What’s more, the SDT is concerned that entities with a limited view of the system should not be setting IROLs or SOLs. We believe this should be the responsibility of entities with a wide-area view, as shown in the standard today; otherwise, we are concerned that reliability may be jeopardized. Commenters – including one from the Transmission Owner segment – have offered this same justification.

#### ***IRO-005-2—Reliability Coordination – Current Day Operations (addressed in the Ad Hoc Report)***

The SDT chose not to adopt the revision to IRO-005-2 proposed by the Ad Hoc Group. This revision would have added a new requirement that would read, “The Generator Operator shall immediately inform the Transmission Operator of the status of the Special Protection System, including any degradation or potential failure to operate as expected for SPS relay or control equipment under its control.” The SDT initially ~~arrived at this decision~~ determined that IRO-005-2 did not require modification because of the ~~planned~~ October 2011 retirement of ~~IRO-005-2~~ the standard. In subsequent meetings, the SDT also reached the conclusion that there is no reliability gap as PRC-001-1 R2 already requires the Generator Operator to notify reliability entities of relay or equipment failures. The SDT believes that a Special Protection System is a form of protection system and therefore any degradation or potential failure to operate as expected would be required to be reported by the Generator Operator to reliability entities (Balancing Authorities, Transmission Operators, and Reliability Coordinators).

#### ***~~Personnel Performance, Training, and Qualifications (PER) Standards~~***

The SDT also chose not to propose the revisions *PER Standards (PER-001-0 and PER-002-0 were addressed in the Ad Hoc Report; PER-002-0 was addressed in the NERC Directive; and PER-003-1 was addressed in the FERC Order)*

The Ad Hoc Group had proposed changes to PER-001-0—Operating Personnel Responsibility and Authority ~~and~~ PER-002-0—Operating Personnel Training ~~that were proposed by the Ad Hoc Group.~~ For PER-001-0, the Ad Hoc Group ~~had~~ proposed adding a new R2 that would read “Each Generator Operator shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Generation Facility and Generation Interconnection Facility, and the responsibility and authority to follow the directives of reliability authorities including the Transmission Operator and Balancing Authority.” To PER-002-0, the Ad Hoc Group proposed adding the Generator Operator to R1 (“Each Transmission Operator, Generator Operator, and Balancing Authority shall be staffed with adequately trained operating personnel”) and adding a new R3 that would read: “Each Generator Operator shall implement an initial and continuing training program for all operating personnel that are responsible for operating the Generator Interconnection Facility that verifies the personnel’s ability and understanding to operate the equipment in a reliable manner.”

In its Directive, NERC does not address PER-001-0, but it states the following with respect to PER-002-0:

“The registered entity will develop an appropriate training program that contains the necessary elements for the GO/GOP operating a transmission facility to understand fully the impacts of the operation on the BPS, such as equipment involved, including protection systems, the coordination aspects with the TO/TOP to which it is connected, and the protocols for and impacts of operating facilities associated with the transmission facility. The objective of this training is to ensure that the GO/GOP is completely aware of its obligations to follow the directives of the appropriate TOP and has personnel with the skills and training to execute these obligations in the best interest of reliability.”

These proposed changes to the PER standards have little to do with responsibilities that relate specifically to a generator interconnection Facility. Issues related to the training of Generator Operators existed separately from the work of Project 2010-07, and the SDT agrees that its scope limits its efforts to standards that are directly related to generator requirements at the transmission interface. The SDT also cites past FERC Orders as proof that this issue is not within the scope of Project 2010-07. In Order 693, FERC directed NERC to "expand the applicability of the personnel training Reliability Standard, PER-002-0, to include (i) generator operators centrally-located at a generation control center with a direct impact on the reliable operation of the Bulk-Power System..." In Order 742, FERC reaffirmed this, stating that it is "not modifying the Order No. 693 directive regarding training for certain generator operator dispatch personnel, nor are we expanding a generator operator’s responsibilities—.”

Centrally-located generator operators working at a generation control center typically dispatch the output from multiple generating units. As such, they can be called upon to comply with orders from their Balancing Authority that may have a significant impact on the reliable operation of the BES. Their training would be covered by proposed ~~changechanges~~ to PER-002-0 and Order 742. Generator Operators who deal with interconnection ~~facilitiesFacilities~~ at individual generating plants, on the other hand, typically do not receive reliability-based orders specific to the interconnection Facilities and are therefore not covered by Order 742. Further, the SDT believes there is no reliability gap as TOP-001-1 R3 already requires Generator Operators ~~are, under currently approved reliability standards, required~~ to follow the directives issued by a Balancing Authority, Reliability Coordinator or of the appropriate Transmission Operator. Operators.

These training-related items are clearly important ones for the Commission, but the SDT does not think it is appropriate to fold modifications to these PER standards into the scope of its work ~~until/unless~~ it is specifically directed to do so. For now, modifications to PER-002-0 based on Order 693 directives are already included in NERC's Issue Database (P. 52-53) to be addressed by a future project. PER-001-0 is not addressed in the Issues Database, but the Project 2007-03 drafting team has proposed that the standard be retired.

#### ~~Transmission Operations (TOP) Standards~~

~~For TOP standards, the Ad Hoc Group proposed a number of new requirements that the SDT does not see as supportive of reliability. This set of standards was somewhat difficult to analyze, as the Project 2007-03 — Real-time Transmission Operations drafting team has made significant changes to TOP-001 through TOP-008, resulting in three proposed TOP standards where are currently eight (see the project's Implementation Plan). The Project 2010-07 reviewed both the FERC approved TOP standards and the fifth draft of the modified standards in Project 2007-03 to determine whether it needed to propose any additional changes to cover radial generator interconnection Facilities. In addition, the Project 2010-07 SDT contacted the Project 2010-07 to get its opinion as to whether there might be any reliability gaps related to generator interconnection facilities. No such changes will be proposed for the reasons outlined below.~~

~~The Ad Hoc Group proposed adding two new requirements to~~ The FERC Order does not address PER-001-0 or PER-002-0, but it does address PER-003-1. In paragraphs 67 and 81 of the FERC Order, FERC expresses concern that operational control over the transmission line breakers owned by the entities in question are not under the control of NERC certified operators. FERC goes on to say that "Reliability Standard PER-003-001 requires NERC certification of all operators that have responsibility for the real-time operation of the interconnected Bulk Electric System. When switching the tie-line in or out of service, operators must have the appropriate credentials and training to properly perform the switching and coordinate the switching to prevent adverse impacts such as the introduction of faults on the system."

The SDT can find no evidence that the kinds of training requirements for operating the breakers of the generator interconnection Facility cited in the FERC Order exist elsewhere for other entities that operate breakers on lines. For instance, Transmission Owners that are not also Transmission Operators are not required to undergo any sort of training. The SDT does not mean to dismiss this issue altogether, and it may be that training should be expanded to include Generator Owners, Generator Operators, Transmission Owners, end users, and possibly others, but the development of such requirements would have implications far beyond the scope and expertise of this team.

**PRC-001-1—System Protection Coordination (addressed in the NERC Directive and the FERC Order)**

The NERC Directive addresses PRC-001-1 R2, R2.2, and R4. The FERC Order addresses these requirements, along with Requirement R6.

About R2 and R4, NERC’s Directive simply states: “PRC-001-R2 requires notification and corrective action for relay or equipment failure. R4 coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.”

In paragraphs 64 and 78 of the FERC Order, FERC expresses concern that “there is a risk of an adverse impact on reliability if the protection relays or protection systems on the [entity’s] line are not coordinated with those on the transmission network facilities in its area.”

Generator Operators and the scope of protection equipment for generation interconnection Facilities are already appropriately accounted for in this standard in requirement R2 and sub-requirement R2.2. The language used in R2 that applies to the Generator Operator uses the general terms “relay or equipment failures” which would include not only generator relaying, but generator interconnection relaying in the Generator Operator’s scope as well. The Generator Operator is required to notify the Transmission Operator and Host Balancing Authority in R2.1 “if a protective relay or equipment failure reduces system reliability.” Requirement R2.2 requires the affected Transmission Operator to notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. Thus, applying R2.2 to a Generator Operator would be redundant to R2.1. If a Generator Operator had a relay or equipment failure on its Facility, including its interconnection Facility it would be required to report that to its Transmission Operator under R2.1, and the Transmission Operator is then required to notify its Reliability Coordinator and other affected Transmission Operators and Balancing Authorities under R2.2.

PRC-001-1 R4 states, “Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.” A sole-use generator interconnection Facility does not constitute a major transmission line or major interconnection with neighboring Generator Operators, Transmission Operators, and Balancing Authorities. Thus, R4 should not be revised to include



Generator Operators. In general, any coordination that might be required is covered by the fact that the Transmission Operator that is connected to a major transmission lines or interconnection has the requirement to coordinate protection on the interconnection, and there is no reliability gap.

PRC-001-1 R6 states, “Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.” It is clearly the responsibility of the Transmission Operator and/or Balancing Authority to monitor the Special Protection System, as they are the entity with a wide-area view, not the responsibility of a Generator Owner/Generator Operator with a local-area view who happens to have generator interconnection Facilities in the area. The requirement focuses on the Transmission Operator and Balancing Authority monitoring the status of each Special Protection System *in their area*; there is no “area” for the Generator Operator to monitor. For these reasons, there is no need to make this requirement applicable to Generator Operators.

***TOP-001-1—Reliability Responsibilities and Authority (addressed in the Ad Hoc Report, NERC Directive, and FERC Order)***

Both the NERC Directive and the FERC Order discuss making TOP-001-1 R1 applicable to Generator Operators. About TOP-001-1, the NERC Directive simply states: “TOP-001-1 R1 ensures personnel assigned to operate BES transmission facilities have clear and unambiguous authority to operate those facilities.” With respect to R1, paragraphs 68 and 83 of FERC’s Order focus on ensuring that “system operators have the authority to take actions to maintain Bulk-Power System facilities within operating limits.”

TOP-001-1 R1 states, “Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.” TOP-001-1 R3 appropriately requires the GOP to comply with reliability directives issued by the Transmission Operator “unless such actions would violate safety, equipment, regulatory or statutory requirements.” These requirements effectively give the Transmission Operator the necessary decision-making authority over operation of all generator Facilities up to the point of interconnection. Thus, no changes to TOP-001-1 are necessary.

Additionally, the Ad Hoc Group proposed adding two new requirements to TOP-001-1. The first was proposed as R9 and read: “The Generator Operator shall coordinate the operation of its Generator Interconnection Facility with the Transmission Operator to whom it interconnects in order to preserve Interconnection reliability...” The SDT does not agree that ~~this change is necessary.~~ TOP-001-1 needs to apply to Generator Operators in any form. TOP-002-2 R3 (proposed to be covered in the future by TOP-003-2, as outlined in Project 2007-03’s Implementation Plan) already requires the Generator Operator to coordinate its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. These entities are, in turn, required to coordinate with their respective



Transmission Operator. Additionally, TOP-002-2 R4 (proposed to be covered in the future by TOP-003-2, as outlined in Project 2007-03's Implementation Plan) requires each Balancing Authority and Transmission Operator to coordinate with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator. With these requirements, Generator Operators are already required to provide necessary operations information to Transmission Operators. To require the same thing in TOP-001-1 would be redundant.

The second new requirement proposed by the Ad Hoc Group for TOP-001-1 was R10, which was to read: "The Transmission Operator shall have decision-making authority over operation of the Generator Interconnection Operational Interface at all times in order to preserve Interconnection reliability." As cited above, TOP-002-2 R3 (proposed to be covered in the future by TOP-003-2, as outlined in Project 2007-03's Implementation Plan) already requires the Generator Operator to coordinate with its interconnecting Transmission Operator. Further, TOP-001-1 R3 (proposed to be covered in the future in the proposed IRO-001-2 R2 and R3) already requires the Generator Operator to comply with reliability directives issued by the Transmission Operator. These requirements effectively give the Transmission Operator decision-making authority over operation of all generator Facilities up to the point of interconnection. To require the same thing in TOP-001-1 would be redundant.

**TOP-004-2—Transmission Operations (addressed in the NERC Directive and the FERC Order)**

Both the NERC Directive and the FERC Order address the application of TOP-004-2 R6 to Generator Operators. In its Directive, NERC simply states: "TOP-004-2 R6 ensures formal policies and procedures are formulated to provide for coordination of activities that may impact reliability." In paragraphs 67 and 82 of the FERC Order, FERC talks about entities ensuring the development of coordination protection to coordinate switching a generator interconnection Facility in and out of service, since different entities have control over different ends of the line. FERC concludes that for the entities in question, TOP-004-2 R6 must apply.

Requirement R6 and its sub-requirements state: "R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: R6.1. Monitoring and controlling voltage levels and real and reactive power flows, R6.2. Switching transmission elements, R6.3. Planned outages of transmission elements, R6.4. Responding to IROL and SOL violations."

TOP-001-1 R3 appropriately requires the Generator Operator to comply with reliability directives issued by the Transmission Operator. These requirements give the Transmission Operator the necessary decision-making authority over operation of all generator Facilities, including interconnection Facilities, up to the point of interconnection. Further, TOP-002-2 R3 requires the

Generator Owner to coordinate its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. These entities are, in turn, required to coordinate with their respective Transmission Operators (also in TOP-002-2 R3). Each Balancing Authority and Transmission Operator is also then required to coordinate with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator (in TOP-002-2 R4). The coordination with which NERC and FERC are concerned is already addressed by these other requirements.

The Ad Hoc Group ~~also had~~ proposed a new requirement, R7, for TOP-004-2—~~Transmission Operations~~ that would read: “The Generator Operator shall operate its Generator Interconnection Facility within its applicable ratings.” The SDT does not agree that a reliability gap exists, because an operator has a fiduciary obligation to protect a Facility for which it is operationally responsible. FAC-008-1—Facility Ratings Methodology and FAC-009-1—Establish and Communicate Facility Ratings already infer that the reason for establishing a ratings methodology and communicating ~~facility ratings~~ Facility Ratings to the Reliability Coordinator, Planning Authority, Transmission Planner, and Transmission Operator is “...for use in reliable planning and operation of the Bulk Electric System.” Further, TOP-004-2 is proposed to be retired under the work of the Project 2007-03 drafting team. Its requirements will either be deleted or assigned elsewhere.

~~The Ad Hoc team proposed to add~~ **TOP-006-1—Monitoring System Conditions (addressed in the NERC Directive; the SDT believes NERC intended to refer to TOP-006-2)**

Only the NERC Directive addresses TOP-006. It states: “TOP-006-1 R3 ensures technical information is provided to the responsible personnel; R6 ensures correct and accurate data to TOP and BA.” But PRC-001-1 R1 (“Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area”) addresses the necessary Generator Operator requirements with respect to TOP-006-2 R3. The SDT believes that knowledge of the purpose and limitations of protection system schemes applied in its area (required in PRC-001-1 R1) constitutes knowledge of “the appropriate technical information concerning protective relays” (required in TOP-006-1 R3).

TOP-006-2 R6 states “Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.” FAC-001-1 R2.1.6 already requires the Transmission Owner’s facility connection requirements to address “metering and telecommunications.” Any generator Facility that interconnected with a Transmission Owner would have had to meet their Facility connection and system performance requirements for metering and telecommunications. Thus, there is no reliability gap.

**TOP-008-1—Response to Transmission Limit Violations (addressed in the Ad Hoc Report)**

Only the Ad Hoc Report addressed TOP-008-1, and it proposed a new requirement, R5, to TOP-008-1—Response to Transmission Limit Violations that would read “The Generator Operator shall disconnect the Generator Interconnection Facility when safety is jeopardized or the overload or abnormal voltage or reactive condition persists and generating equipment or the Generator Interconnection Facility is endangered. In doing so, the Generator Operator shall notify its Transmission Operator and Balancing Authority impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.” The SDT sees no reliability benefit to adding this requirement. TOP-001-1 R7 (“Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless...”) and its parts give the Generator Operator authority over its Facilities, which would include the generator interconnection Facility. If there is an outage, R7.1 requires the Generator Operator to notify and coordinate with its Transmission Operator, which is required to notify the Reliability Coordinator and other affected Transmission Operators. And as with TOP-004-2, the Project 2007-03 drafting team has proposed to ~~deletingdelete~~ all of TOP-008-1’s requirements and retiring the standard.

### Conclusion

The Project 2010-07 SDT is confident that the changes it has proposed address the reliability gap that exists with respect to the responsibilities of Generator Owners and Generator Operations that own ~~radial~~sole-use interconnection Facilities. The changes to FAC-001~~and~~, FAC-003 ~~and~~ ~~now~~PRC-004 ~~have~~ have been supported by stakeholders during comment periods, and there has been no strong support of technical justification provided for bringing other standards into the scope of this project.

~~That said, the SDT recognizes the success of its work depends on stakeholders, NERC, and FERC agreeing that generator requirements at the transmission interface are covered under NERC Reliability Standards, both for the sake of reliability and to prevent further unwarranted registration of Generator Owners and Generator Operators as Transmission Owners and Transmission Operators. If the SDT’s work does not close the gap in the eyes of all parties, that work will have been unsuccessful, so the SDT is considering all feedback it receives with request to this project. While it is posting changes to only FAC-001, FAC-003, and PRC-004, and stands by that decision, it will continue to consider whether glossary term additions/modifications and modifications to other standards could enhance the reliability impact of this project. Based on conversations with NERC and FERC staff, and review of FERC’s Order Denying Compliance Registry Appeals of Cedar Creek Wind Energy and Milford Wind Corridor Phase I (135 FERC ¶ 61,241), the SDT is discussing whether it should consider the following requirements for further review: EOP-005-1 R1, R2, R6, R7; FAC-014-2 R2; PER-003-1 R1, R1.1, R1.2; PRC-001-1 R2, R2.2, R4, R6; PRC-004-1 R1; TOP-001 R1; TOP-004-2 R6, R6.1, R6.2, R6.3, R6.4; and TOP-006-1 R3. The SDT is actively seeking stakeholder feedback as to whether, in light of these orders, it should consider additional standards and or new or modifications to existing definitions as it proceeds with its work.~~

## Technical Justification: FAC-001-1

### Project 2010-07 Generator Requirements at the Transmission Interface

In response to the June 17-July 17, 2011 formal posting of the proposed standard changes in Project 2010-07, the standard drafting team (SDT) received stakeholder comments on FAC-001-1 expressing concern about the feasibility of a Generator Owner receiving and executing an interconnection request on one of its interconnection Facilities, as well as concern about the market-related processes that would go along with such an interconnection request. In this technical justification document, the SDT seeks to further clarify its rationale for making the proposed FAC-001-1 applicable to qualifying Generator Owners.

While the SDT understands that interconnection requests for Generator Owner Facilities are still relatively rare, in the past (for instance, 134 FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities. The SDT acknowledges that FERC does not have jurisdiction over all Generator Owners, but realizes that the potential exists for a third party to request to interconnect its planned generator with an existing generator interconnection Facility (whose use at the time of the request is solely to transmit capacity, energy, and ancillary services from the existing generator).

The SDT discussed the various ways such an interconnection could occur and agrees that if the third party interconnection could be accomplished without the need for the existing Generator Owner to develop its own connection requirements and system performance requirements and determine impacts on the interconnected transmission systems, this standard need not apply to the Generator Owner. And the SDT agrees that in many cases, these connection requirements, system performance requirements, and determined impacts on the interconnected transmission systems are currently determined by entities registered as either a Transmission Owner, Transmission Planner, and/or Transmission Service Provider. However, the SDT remains convinced (based on the orders cited above) that there may be occasions where FERC or another regulatory agency compels the Generator Owner to allow a third party to interconnect its planned generator with an existing generator interconnection Facility. Where this occurs, the SDT feels it is necessary for the existing owner of that generator interconnection Facility to provide connection requirements to the third party that requests interconnection. The SDT also believes, and many comments seem to support, that performance requirements and a determination of impact to the interconnected transmission systems need to be evaluated by some entity. The question becomes which entity.

The SDT can only work within the standards development process. We cannot address other regulatory issues such as FERC-mandated open transmission access (Order 888 and subsequent) or state or provincial jurisdiction over generation or transmission assets. While we acknowledge these

mechanisms exists and may come into play in the scenarios described in the proposed FAC-001-1, we as the SDT can only deal within the context of reliability standards. For this reason, R2 indicates that FAC-001-1 applies only when a Generator Owner has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility. The SDT's reasoning here is that if the owner of the existing generator interconnection Facility agrees, or is compelled, to allow a third party to interconnect, and can do so using existing agreements, contracts, and/or tariffs (and thereby avoid having an executed Agreement to evaluate the reliability impact of interconnecting third party Facility to the Generator Owner's existing Facility), and thus avoid having to develop its own connection requirements or perform impact studies, it will. In this example, it is likely that the existing Transmission Owner, Transmission Planner, and/or Transmission Service Provider processes and Agreements will be utilized and the purpose of FAC-001-1 will be met without applying this standard to the Generator Owner.

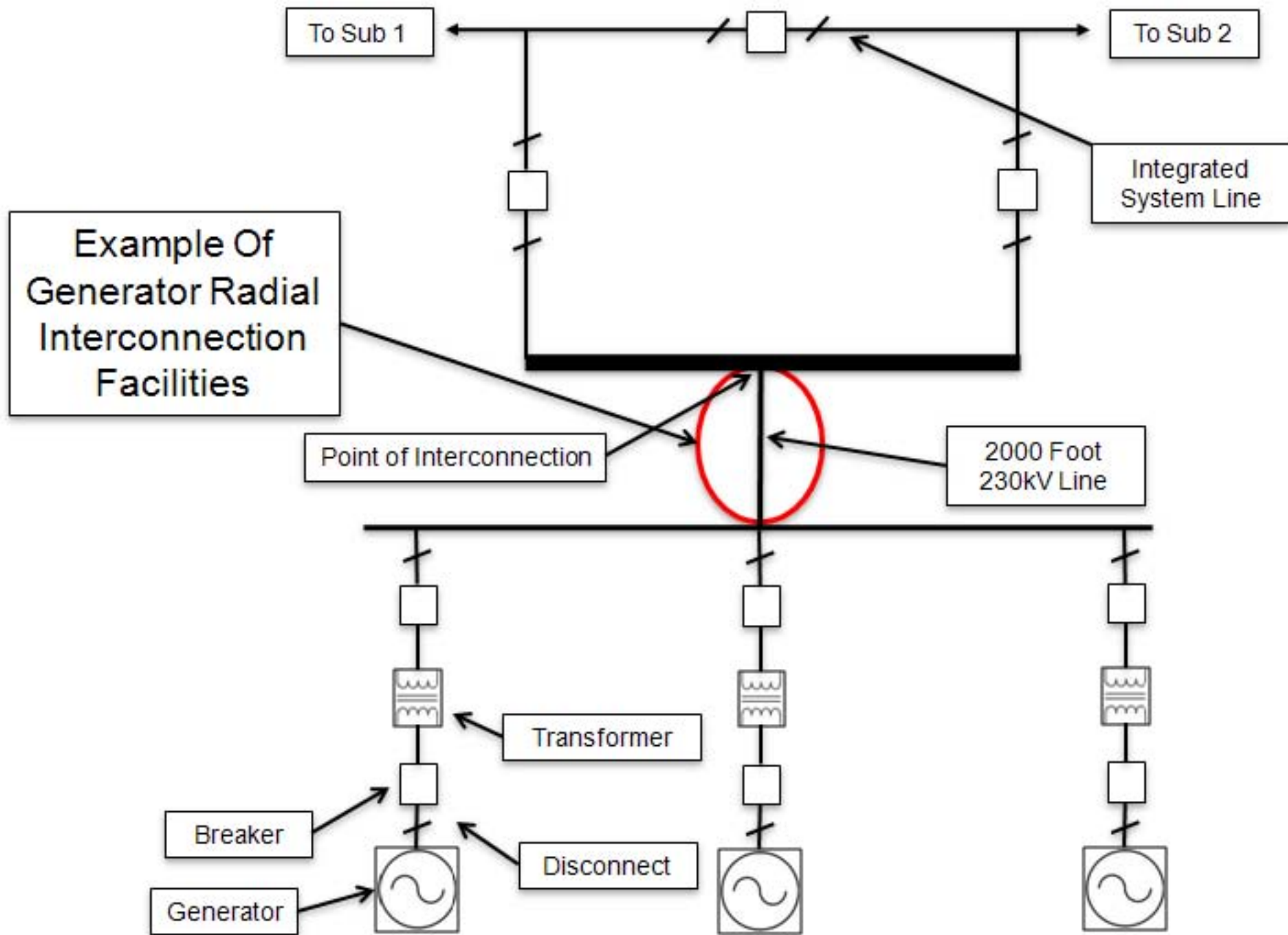
If, on the other hand, the owner of the existing generator interconnection Facility agrees, or is compelled, to allow a third party to interconnect, but cannot do so without having to develop its own connection requirements or perform impact studies, the SDT believes that the potential for a reliability gap exists. This might occur, for instance, if the owner of an existing generator interconnection Facility was compelled to allow interconnection and to implement open transmission access. In this example, (under FERC Order 888 and subsequent orders), the existing interconnection owner becomes a Transmission Service Provider and is required to have an Open Access Transmission Tariff (OATT). FERC's pro forma OATT requires the Transmission Service Provider to, among other things, perform system impact and feasibility studies. In order to do so, such studies must be coordinated with other Transmission Service Providers and Transmission Planners. And, to further complicate the issue, the SDT has been informed that in Texas, a Generator Owner is not allowed to own transmission.

Clearly, these issues are complex and not all are within the jurisdiction of federal or provincial regulators. For these reasons, the SDT took the only approach it found workable. If, and only if, the existing owner of a generator interconnection Facility has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to its existing generation Facility would the proposed FAC-001-1 apply. The SDT believes that this is most likely to occur if the owner of an existing generator interconnection Facility is compelled to allow a third party to interconnect and adopt open transmission access. However, the SDT cannot be certain this is the only example and it therefore proposes to add this new requirement to FAC-001-1. In doing so, the SDT acknowledges that the Generator Owner may not, at the time it agrees or is compelled to allow a third party to interconnect, have the necessary expertise to conduct the required interconnect studies to meet this standard. However, the SDT believes that, upon executing such Agreement, the Generator Owner will have to acquire such expertise. How the Generator Owner chooses to do so is not for the SDT to determine. The SDT is tasked with identifying potential reliability gaps and addressing such gaps through the standards development process.

The SDT does agree with many comments asking that the Generator Owner not be required to maintain its connection requirements, and there was robust discussion among the team and observers. Some were concerned that, without an obligation to maintain, there would not be a review to ensure compliance with NERC Reliability Standards and applicable Regional Entity, subregional, Power Pool, and individual Transmission Owner planning criteria. Others were concerned that the third party requesting interconnection might not actually interconnect, but the owner of the existing generator interconnection Facility would, having executed an evaluation agreement, be forever obligated to maintain connection requirements. In the end, the SDT agreed that if the owner of the existing generator interconnection Facility adopted open access or was determined to be providing “transmission service” it was likely that its existing registration would be re-evaluated and that the issue would be more appropriately addressed at that time. The SDT has therefore agreed to remove maintenance requirements for Generator Owners from both Requirement R2 and Requirement R4 in the proposed FAC-001-1.

We hope that you have found this explanation of our rationale helpful, but if you have further suggestions for improvement or clarity, please submit them in your comments on this latest posting.





Example Of  
Generator Radial  
Interconnection  
Facilities

To Sub 1

To Sub 2

Integrated  
System Line

Point of Interconnection

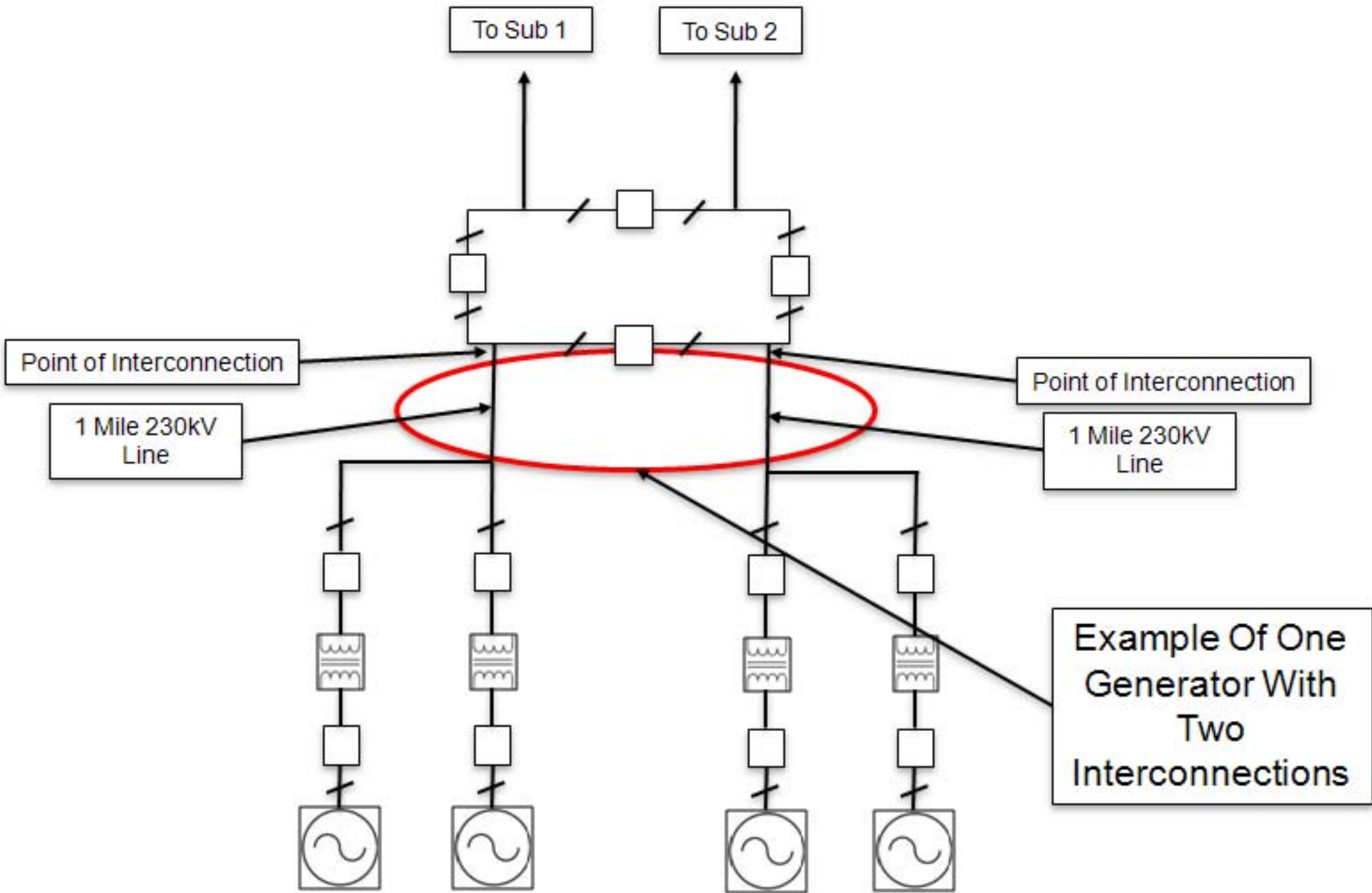
2000 Foot  
230kV Line

Transformer

Breaker

Disconnect

Generator





**Project 2010-07—Generator Requirements at the Transmission Interface  
Justification for Nonbinding Poll**

R#	Compliance with NERC's VSL Guidelines	<b>Guideline 1</b>  Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	<b>Guideline 2</b>  Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties  Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent  Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	<b>Guideline 3</b>  Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	<b>Guideline 4</b>  Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
FAC-001-1 R1	The drafting team made no changes to the R1 VSLs filed by NERC staff on March 21, 2011 (in Supplemental Information to the NERC Compliance Filing in Response to the Order on Violation Severity Levels Proposed by the ERO). Because the drafting team made no changes to R1, the team determined that any further changes to R1's VSLs would be outside of the scope of Project 2010-07.	The drafting team made no changes to the R1 VSLs filed by NERC staff on March 21, 2011 (in Supplemental Information to the NERC Compliance Filing in Response to the Order on Violation Severity Levels Proposed by the ERO), except to correct typographical errors.. Because the drafting team made no changes to R1, the team determined that any further changes to R1's VSLs would be outside of the scope of Project 2010-07.	The drafting team made no changes to the R1 VSLs filed by NERC staff on March 21, 2011 (in Supplemental Information to the NERC Compliance Filing in Response to the Order on Violation Severity Levels Proposed by the ERO), except to correct typographical errors. Because the drafting team made no changes to R1, the team determined that any further changes to R1's VSLs would be outside of the scope of Project 2010-07.	The drafting team made no changes to the R1 VSLs filed by NERC staff on March 21, 2011 (in Supplemental Information to the NERC Compliance Filing in Response to the Order on Violation Severity Levels Proposed by the ERO), except to correct typographical errors. Because the drafting team made no changes to R1, the team determined that any further changes to R1's VSLs would be outside of the scope of Project 2010-07.	The drafting team made no changes to the R1 VSLs filed by NERC staff on March 21, 2011 (in Supplemental Information to the NERC Compliance Filing in Response to the Order on Violation Severity Levels Proposed by the ERO), except to correct typographical errors. Because the drafting team made no changes to R1, the team determined that any further changes to R1's VSLs would be outside of the scope of Project 2010-07.
FAC-001-1 R2	The VSLs for R2 are written in accordance with NERC's VSL Guideline's formatting recommendations. The requirement is not of the pass/fail variety, so the VSL assignments have been gradated based on when the Generator Owner documented and published the Facility connection requirements. As is recommended by NERC's VSL Guidelines, the drafting team	Because this is a new requirement, there is no current level of compliance with which the VSL assignments can be compared.	The requirement has gradated VSLs; therefore, Guideline 2a is not applicable. The gradated VSLs ensure uniformity and consistency among all approved Reliability Standards in the determination of penalties.  The proposed text is clear, specific, and does not contain general, relative or subjective language (and is not subject to the	The drafting team compared the VSLs to the requirement language to ensure that the VSLs do not redefine or undermine the requirement's reliability goal. The VSL assignments are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.	The VSLs are based on a single violation, not on a cumulative number of violations of the same requirement over a period of time, thus fulfilling Guideline 4.

**Project 2010-07—Generator Requirements at the Transmission Interface  
Justification for Nonbinding Poll**

R#	Compliance with NERC’s VSL Guidelines	<b>Guideline 1</b>  Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	<b>Guideline 2</b>  Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties  Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent  Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	<b>Guideline 3</b>  Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	<b>Guideline 4</b>  Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
	identified a reasonable delay for the Lower VSL and then used 10-day increments to develop the Moderate, High, and Severe VSLs.		possibility of multiple interpretations), satisfying Guideline 2b.		
FAC-001-1 R3	For its proposed changes to VSLs for FAC-001-1 R3, the drafting team used the FERC-approved VSLs (then FAC-001-0 R2) in 135 FERC ¶ 61,166 as a starting point. The VSLs were already appropriately gradated with penalties based on the recommendation for requirements with parts that contribute equally to the requirement, and removing the second half of R3’s Severe VSL simply avoids any double jeopardy compliance issues, as indicated in the Guideline 2 explanation.	The drafting team’s slight modification to the Severe VSL for R3 does not signal a lower compliance threshold than previously existed.	The requirement has gradated VSLs; therefore, Guideline 2a is not applicable. The gradated VSLs ensure uniformity and consistency among all approved Reliability Standards in the determination of penalties.  The drafting team determined that the second half of the Severe VSL in R3 (“The responsible entity does not have Facility connection requirements”) could lead to double jeopardy because of its redundancy with the Severe VSLs in R1 (“The Transmission Owner did not develop Facility connection requirements”) and R2 (“The Generator Owner failed to document and publish and thereafter maintain Facility connection requirements until more than 80 days...”). Thus, the	The drafting team compared the VSLs to the requirement language to ensure that the VSLs do not redefine or undermine the requirement’s reliability goal. After modifying “Transmission Owner” to “responsibility entity”, the VSL assignments are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.	The VSLs are based on a single violation, not on a cumulative number of violations of the same requirement over a period of time, thus fulfilling Guideline 4.

**Project 2010-07—Generator Requirements at the Transmission Interface  
Justification for Nonbinding Poll**

R#	Compliance with NERC's VSL Guidelines	<b>Guideline 1</b>  Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	<b>Guideline 2</b>  Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties  Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent  Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	<b>Guideline 3</b>  Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	<b>Guideline 4</b>  Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
			second half of the VSL for R3 has been deleted.  With this change, the text is clear, specific, and does not contain general, relative or subjective language (and is not subject to the possibility of multiple interpretations), satisfying Guideline 2b.		
FAC-001-1 R4	The drafting team made no changes to the R4 VSLs (then VSLs for R3) approved by FERC in 135 FERC ¶ 61,166. Because, with this posting, the drafting team made no changes to R4 compared to the FERC approved version (then R3), the team determined that any further changes to R4's VSLs would be outside of the scope of Project 2010-07.	The drafting team made no changes to the R4 VSLs (then VSLs for R3) approved by FERC in 135 FERC ¶ 61,166. Because the drafting team made no changes to R4 compared to the FERC approved version (then R3), the team determined that any further changes to R4's VSLs would be outside of the scope of Project 2010-07.	The drafting team made no changes to the R4 VSLs (then VSLs for R3) approved by FERC in 135 FERC ¶ 61,166. Because the drafting team made no changes to R4 compared to the FERC approved version (then R3), the team determined that any further changes to R4's VSLs would be outside of the scope of Project 2010-07.	The drafting team made no changes to the R4 VSLs (then VSLs for R3) approved by FERC in 135 FERC ¶ 61,166. Because the drafting team made no changes to R4 compared to the FERC approved version (then R3), the team determined that any further changes to R4's VSLs would be outside of the scope of Project 2010-07.	The drafting team made no changes to the R4 VSLs (then VSLs for R3) approved by FERC in 135 FERC ¶ 61,166. Because the drafting team made no changes to R4 compared to the FERC approved version (then R3), the team determined that any further changes to R4's VSLs would be outside of the scope of Project 2010-07.

**VRFs for FAC-001-1:**

**Project 2010-07—Generator Requirements at the Transmission Interface  
Justification for Nonbinding Poll**

The VRFs for FAC-001-1 were transferred from NERC's VRF Matrix – which includes VRFs that have already been approved by FERC – to bring the formatting of the standard up to date. A Medium VRF was added to new Requirement R2, which applies to Generator Owners, to match the Medium VRF for the comparable Requirement R1, which applies to Transmission Owners.

**A. Introduction**

- 1. Title:** **Transmission and Generation Protection System Maintenance and Testing**
- 2. Number:** PRC-005-1.1b
- 3. Purpose:** To ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested.
- 4. Applicability**
  - 4.1.** Transmission Owner.
  - 4.2.** Generator Owner.
  - 4.3.** Distribution Provider that owns a transmission Protection System.
- 5. Effective Date:** In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements become effective upon Board of Trustee's adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

**B. Requirements**

- R1.** Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:
  - R1.1.** Maintenance and testing intervals and their basis.
  - R1.2.** Summary of maintenance and testing procedures.
- R2.** Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Entity on request (within 30 calendar days). The documentation of the program implementation shall include:
  - R2.1.** Evidence Protection System devices were maintained and tested within the defined intervals.
  - R2.2.** Date each Protection System device was last tested/maintained.

**C. Measures**

- M1.** Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System that affects the reliability of the BES, shall have an associated Protection System maintenance and testing program as defined in Requirement 1.
- M2.** Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System that affects the reliability of the BES, shall have evidence it provided documentation of its associated Protection System maintenance and testing program and the implementation of its program as defined in Requirement 2.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Regional Entity.

**1.2. Compliance Monitoring Period and Reset Time Frame**

One calendar year.

**1.3. Data Retention**

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System, shall retain evidence of the implementation of its Protection System maintenance and testing program for three years.

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

**1.4. Additional Compliance Information**

The Transmission Owner and any Distribution Provider that owns a transmission Protection System and the Generator Owner that owns a generation or generator interconnection Facility Protection System, shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

**2. Violation Severity Levels (no changes)**

**E. Regional Differences**

None identified.

**Version History**

<b>Version</b>	<b>Date</b>	<b>Action</b>	<b>Change Tracking</b>
0	April 1, 2005	Effective Date	New
1	December 1, 2005	<ol style="list-style-type: none"> <li>1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>2. Added “periods” to items where appropriate.</li> <li>3. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> </ol>	01/20/05
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation

**Standard PRC-005-1.1b — Transmission and Generation Protection System Maintenance and Testing**

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1a	February 17, 2011	Adopted by Board of Trustees	
1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC's Order is effective as of September 26, 2011)	
1.1a	February 1, 2012	Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner's responsibility	Revision under Project 2010-07
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC's Order dated March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
1.1b	April 23, 2012	Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.	Revision under Project 2010-07

## Appendix 1

Requirement Number and Text of Requirement
<p><b>R1.</b> Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:</p> <p><b>R1.1.</b> Maintenance and testing intervals and their basis.</p> <p><b>R1.2.</b> Summary of maintenance and testing procedures.</p> <p><b>R2.</b> Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include:</p> <p><b>R2.1</b> Evidence Protection System devices were maintained and tested within the defined intervals.</p> <p><b>R2.2</b> Date each Protection System device was last tested/maintained.</p>
<b>Question:</b>
Is protection for a radially-connected transformer protection system energized from the BES considered a transmission Protection System subject to this standard?
<b>Response:</b>
<p>The request for interpretation of PRC-005-1 Requirements R1 and R2 focuses on the applicability of the term “transmission Protection System.” The NERC Glossary of Terms Used in Reliability Standards contains a definition of “Protection System” but does not contain a definition of transmission Protection System. In these two standards, use of the phrase transmission Protection System indicates that the requirements using this phrase are applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directly from the BES.</p> <p>A Protection System for a radially connected transformer energized from the BES would be considered a transmission Protection System and subject to these standards only if the protection trips an interrupting device that interrupts current supplied directly from the BES and the transformer is a BES element.</p>



## Appendix 2

<b>Requirement Number and Text of Requirement</b>
<p><b>R1.</b> Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:</p> <p><b>R1.1.</b> Maintenance and testing intervals and their basis.</p> <p><b>R1.2.</b> Summary of maintenance and testing procedures.</p>
<p><b>Question:</b></p> <ol style="list-style-type: none"><li>1. Does R1 require a maintenance and testing program for the battery chargers for the “station batteries” that are considered part of the Protection System?</li><li>2. Does R1 require a maintenance and testing program for auxiliary relays and sensing devices? If so, what types of auxiliary relays and sensing devices? (i.e transformer sudden pressure relays)</li><li>3. Does R1 require maintenance and testing of transmission line re-closing relays?</li><li>4. Does R1 require a maintenance and testing program for the DC circuitry that is just the circuitry with relays and devices that control actions on breakers, etc., or does R1 require a program for the entire circuit from the battery charger to the relays to circuit breakers and all associated wiring?</li><li>5. For R1, what are examples of "associated communications systems" that are part of “Protection Systems” that require a maintenance and testing program?</li></ol>
<p><b>Response:</b></p> <ol style="list-style-type: none"><li>1. While battery chargers are vital for ensuring “station batteries” are available to support Protection System functions, they are not identified within the definition of “Protection Systems.” Therefore, PRC-005-1 does not require maintenance and testing of battery chargers.</li><li>2. The existing definition of “Protection System” does not include auxiliary relays; therefore, maintenance and testing of such devices is not explicitly required. Maintenance and testing of such devices is addressed to the degree that an entity’s maintenance and testing program for 3 DC control circuits involves maintenance and testing of imbedded auxiliary relays. Maintenance and testing of devices that respond to quantities other than electrical quantities (for example, sudden pressure relays) are not included within Requirement R1.</li><li>3. No. “Protective Relays” refer to devices that detect and take action for abnormal conditions. Automatic restoration of transmission lines is not a “protective” function.</li><li>4. PRC-005-1 requires that entities 1) address DC control circuitry within their program, 2) have a basis for the way they address this item, and 3) execute the program. PRC-005-1 does not establish specific additional requirements relative to the scope and/or methods included within the program.</li><li>5. “Associated communication systems” refer to communication systems used to convey essential Protection System tripping logic, sometimes referred to as pilot relaying or teleprotection. Examples include the following:<ul style="list-style-type: none"><li>• communications equipment involved in power-line-carrier relaying</li><li>• communications equipment involved in various types of permissive protection system</li></ul></li></ol>

**Standard PRC-005-1.1b — Transmission and Generation Protection System Maintenance and Testing**

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applications

- direct transfer-trip systems
- digital communication systems (which would include the protection system communications functions of standard IEC 618501 as well as various proprietary systems)

## A. Introduction

1. **Title:** Transmission and Generation Protection System Maintenance and Testing
2. **Number:** PRC-005-~~1a~~1.1b
3. **Purpose:** To ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested.
4. **Applicability**
  - 4.1. Transmission Owner.
  - 4.2. Generator Owner.
  - 4.3. Distribution Provider that owns a transmission Protection System.
- ~~5. **Effective Date:** To be determined~~
5. **Effective Date:** In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements become effective upon Board of Trustee's adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

## B. Requirements

- R1. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:
  - R1.1. Maintenance and testing intervals and their basis.
  - R1.2. Summary of maintenance and testing procedures.
- R2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional ~~Reliability Organization~~Entity on request (within 30 calendar days). The documentation of the program implementation shall include:
  - R2.1. Evidence Protection System devices were maintained and tested within the defined intervals.
  - R2.2. Date each Protection System device was last tested/maintained.

## C. Measures

- M1. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System that affects the reliability of the BES, shall have an associated Protection System maintenance and testing program as defined in Requirement 1.
- M2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System that affects the reliability of the BES, shall have evidence it provided

documentation of its associated Protection System maintenance and testing program and the implementation of its program as defined in Requirement 2.

#### D. Compliance

##### 1. Compliance Monitoring Process

###### 1.1. Compliance Monitoring Responsibility

Regional ~~Reliability Organization~~Entity.

###### 1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

###### 1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System, shall retain evidence of the implementation of its Protection System maintenance and testing program for three years.

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

###### 1.4. Additional Compliance Information

The Transmission Owner and any Distribution Provider that owns a transmission Protection System and the Generator Owner that owns a generation or generator interconnection Facility Protection System, shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

##### 2. Violation Severity Levels of Non-Compliance(no changes)

~~2.1. Level 1: Documentation of the maintenance and testing program provided was incomplete as required in R1, but records indicate maintenance and testing did occur within the identified intervals for the portions of the program that were documented.~~

~~2.2. Level 2: Documentation of the maintenance and testing program provided was complete as required in R1, but records indicate that maintenance and testing did not occur within the defined intervals.~~

~~2.3. Level 3: Documentation of the maintenance and testing program provided was incomplete, and records indicate implementation of the documented portions of the maintenance and testing program did not occur within the identified intervals.~~

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

#### E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	<ol style="list-style-type: none"> <li>1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>2. Added “periods” to items where appropriate.</li> <li>3. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> </ol>	01/20/05
<del>1</del>	<del>February 7, 2006</del>	<del>Adopted by NERC Board of Trustees</del>	
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by Board of Trustees	
1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC’s Order is effective as of September 26, 2011)	
<del>1.1a</del>	<del>February 1, 2012</del>	<del>Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility</del>	<del>Revision under Project 2010-07</del>
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC’s Order dated March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
<del>1.1b</del>	<del>April 23, 2012</del>	<del>Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.</del>	<del>Revision under Project 2010-07</del>

## Appendix 1

Requirement Number and Text of Requirement
<p><b>R1.</b> Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:</p> <p><b>R1.1.</b> Maintenance and testing intervals and their basis.</p> <p><b>R1.2.</b> Summary of maintenance and testing procedures.</p> <p><b>R2.</b> Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include:</p> <p><b>R2.1</b> Evidence Protection System devices were maintained and tested within the defined intervals.</p> <p><b>R2.2</b> Date each Protection System device was last tested/maintained.</p>
<b>Question:</b>
Is protection for a radially-connected transformer protection system energized from the BES considered a transmission Protection System subject to this standard?
<b>Response:</b>
<p>The request for interpretation of PRC-005-1 Requirements R1 and R2 focuses on the applicability of the term “transmission Protection System.” The NERC Glossary of Terms Used in Reliability Standards contains a definition of “Protection System” but does not contain a definition of transmission Protection System. In these two standards, use of the phrase transmission Protection System indicates that the requirements using this phrase are applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directly from the BES.</p> <p>A Protection System for a radially connected transformer energized from the BES would be considered a transmission Protection System and subject to these standards only if the protection trips an interrupting device that interrupts current supplied directly from the BES and the transformer is a BES element.</p>

## Appendix 2

Requirement Number and Text of Requirement
<p><b>R1.</b> Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:</p> <p><b>R1.1.</b> Maintenance and testing intervals and their basis.</p> <p><b>R1.2.</b> Summary of maintenance and testing procedures.</p>
<p><b>Question:</b></p> <ol style="list-style-type: none"><li>1. Does R1 require a maintenance and testing program for the battery chargers for the “station batteries” that are considered part of the Protection System?</li><li>2. Does R1 require a maintenance and testing program for auxiliary relays and sensing devices? If so, what types of auxiliary relays and sensing devices? (i.e transformer sudden pressure relays)</li><li>3. Does R1 require maintenance and testing of transmission line re-closing relays?</li><li>4. Does R1 require a maintenance and testing program for the DC circuitry that is just the circuitry with relays and devices that control actions on breakers, etc., or does R1 require a program for the entire circuit from the battery charger to the relays to circuit breakers and all associated wiring?</li><li>5. For R1, what are examples of "associated communications systems" that are part of “Protection Systems” that require a maintenance and testing program?</li></ol>
<p><b>Response:</b></p> <ol style="list-style-type: none"><li>1. While battery chargers are vital for ensuring “station batteries” are available to support Protection System functions, they are not identified within the definition of “Protection Systems.” Therefore, PRC-005-1 does not require maintenance and testing of battery chargers.</li><li>2. The existing definition of “Protection System” does not include auxiliary relays; therefore, maintenance and testing of such devices is not explicitly required. Maintenance and testing of such devices is addressed to the degree that an entity’s maintenance and testing program for 3 DC control circuits involves maintenance and testing of imbedded auxiliary relays. Maintenance and testing of devices that respond to quantities other than electrical quantities (for example, sudden pressure relays) are not included within Requirement R1.</li><li>3. No. “Protective Relays” refer to devices that detect and take action for abnormal conditions. Automatic restoration of transmission lines is not a “protective” function.</li><li>4. PRC-005-1 requires that entities 1) address DC control circuitry within their program, 2) have a basis for the way they address this item, and 3) execute the program. PRC-005-1 does not establish specific additional requirements relative to the scope and/or methods included within the program.</li><li>5. “Associated communication systems” refer to communication systems used to convey essential Protection System tripping logic, sometimes referred to as pilot relaying or teleprotection. Examples include the following:<ul style="list-style-type: none"><li>• communications equipment involved in power-line-carrier relaying</li><li>• communications equipment involved in various types of permissive protection system</li></ul></li></ol>

applications

- direct transfer-trip systems
- digital communication systems (which would include the protection system communications functions of standard IEC 618501 as well as various proprietary systems)



# Implementation Plan for PRC-005-1.1a— Transmission and Generation Protection System Maintenance and Testing

## **Prerequisite Approvals**

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

## **Revision to Sections of Approved Standards and Definitions**

There are no proposed revisions to requirements in other already approved standards. PRC-005-1a will be retired when PRC-005-1.1a becomes effective.

## **Compliance with Standard**

The proposed changes to Requirement R1 and R2 are clarifying changes. While there was no reliability gap in the previous version of the standard, if applied literally, there was the possibility for the misperception that the Generator Owner was only responsible for analyzing its generator Protection System, exclusive of its generator interconnection Facility Protection System. The errata changes to R1 and R2 make clear that generator interconnection Facilities are also part of Generator Owners' responsibility in the context of this standard.

Because the change is merely a clarifying change, no additional time for compliance is needed.

## **Effective Date**

In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements become effective upon Board of Trustees' adoption.

# Unofficial Comment Form

## Generator Requirements at the Transmission Interface (Project 2010-07)

Please **DO NOT** use this form to submit comments. Please use the [electronic comment form](#) to submit comments on the first formal posting for Project 2010-07—Generator Requirements at the Transmission Interface. The electronic comment form must be completed by **April 16, 2012**.

[2010-07 Project Page](#)

If you have questions please contact Mallory Huggins at [mallory.huggins@nerc.net](mailto:mallory.huggins@nerc.net) or 202-383-2629.

### Background

During the formal comment period that ended on November 18, 2011, the SDT asked the following question: “The SDT is attempting to modify a set of standards so that radial generator interconnection Facilities are appropriately accounted for in NERC’s Reliability Standards, both to close reliability gaps and to prevent the unnecessary registration of GOs and GOPs as TOs and TOPs. Does the set of standards currently posted achieve this goal?” In response, stakeholders suggested that the proposed revisions to PRC-004-2 should also be made to PRC-005. Accordingly, the SDT has revised PRC-005-1.1a, and is posting it for a formal 45-day comment period and initial ballot. The Standards Committee has authorized waiving the initial 30-day comment period because the changes to PRC-005-1.1a are minor.

The purpose of Project 2010-07 is to ensure that all generator-owned Facilities are appropriately covered under NERC’s Reliability Standards. While many Generator Owners and Generator Operators operate Elements and Facilities that are considered by some entities to be Transmission, these are most often radial Facilities that are not part of the integrated grid, and as such should not be subject to the same standards applicable to Transmission Owners and Transmission Operators who own and operate Transmission Elements and Facilities that are part of the integrated grid.

As part of the BES, generators affect the overall reliability of the BES. However, registering a Generator Owner or Generator Operator as a Transmission Owner or Transmission Operator, as has been the solution in some cases in the past, may decrease reliability by diverting the Generator Owner’s or Generator Operator’s resources from the operation of the equipment that actually produces electricity – the generation equipment itself.

The drafting team’s goal is to ensure that an adequate level of reliability is maintained in the BES by clearly describing which standards need to be applied to generator interconnection Facilities that are not already applicable to Generator Owners or Generator Operators. The SDT believes that properly applying PRC-005-1.1a to Generator Owners as proposed in the redline standard posted for comment supports this objective.

**You do not have to answer all questions. Enter all comments in Simple Text Format.**

1. Based on stakeholder comment, the SDT inserted the phrase “or generator interconnection Facility” in Requirements R1 and R2 of PRC-005-1.1a. While there was no reliability gap in the previous version of the standard, if the Requirements were applied literally, there was the possibility for the misperception that the Generator Owner was only responsible for analyzing its generator Protection Systems, exclusive of its generator interconnection Facility Protection Systems. The clarifying changes to R1 and R2 make clear that generator interconnection Facilities are also part of Generator Owners’ responsibility in the context of this standard. Do you support the addition of the phrase “or generator interconnection Facility” to accomplish this clarification?

Yes

No

Comments:

2. Do you have any other comments that you have not yet addressed? If yes, please explain.

Yes

No

Comments:

# Standards Announcement

## Project 2010-07 Generator Requirements at the Transmission Interface

Ballot Window Open April 6, 2012 through April 16, 2012

### [Available April 6](#)

An initial ballot for PRC-005-1.1a – Transmission and Generation Protection System Maintenance and Testing is **open Friday, April 6 through 8 p.m. Eastern on Monday, April 16, 2012.**

### Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their vote for the standards by clicking [here](#).

### Special Instructions for Submitting Comments with a Ballot

Please note that comments submitted during the formal comment period, the ballot and the non-binding polls use the same electronic form. Therefore, it is NOT necessary for ballot pool members to submit more than one set of comments. Companies or entities with representatives in multiple segments of the ballot pool may submit a single set of comments by identifying themselves as a “group” on the comment form. Likewise, it is **preferable** for a group of separate entities that develop comments jointly to submit the comments as a “group.” **The drafting team requests that all stakeholders (ballot pool members as well as other stakeholders) submit all comments through the electronic comment form, and that companies in multiple segments as well as individual entities that develop joint comments with other entities submit their comments as a “group,” with the list of group members and their associated Industry Segments.**

### Next Steps

The drafting team will consider all comments received during the formal comment period and initial ballot and if needed, make revisions to the standard.

### Background

The purpose of Project 2010-07 is to ensure that all generator-owned Facilities are appropriately covered under NERC’s Reliability Standards. While many Generator Owners and Generator Operators operate Facilities, commonly known as generator interconnection Facilities, that are considered by some entities to be transmission, these are most often radial Facilities that are not part of the integrated grid. As such, they should not be subject to the same standards applicable to Transmission

Owners and Transmission Operators who own and operate Transmission Elements and Facilities that are part of the integrated grid.

As part of the BES, generators also affect the overall reliability of the BES. But registering a Generator Owner or Generator Operator as a Transmission Owner or Transmission Operator, as has been the solution in some cases in the past, may decrease reliability by diverting the Generator Owner's or Generator Operator's resources from the operation of the equipment that actually produces electricity – the generation equipment itself.

The drafting team's goal is to ensure that an adequate level of reliability is maintained in the BES by clearly describing which standards need to be applied to generator interconnection Facilities that are not already applicable to Generator Owners or Generator Operators. The SDT believes that properly applying PRC-005-1.1a to Generator Owners as proposed in the redline standard posted for comment supports this objective.

Before reviewing the standards, the drafting team encourages all stakeholders to read the technical justification resource document it has provided to describe its rationale and its work thus far.

Additional information is available on the [project page](#).

### **Standards Development Process**

The [Standard Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. For more information or assistance, please contact Monica Benson at [monica.benson@nerc.net](mailto:monica.benson@nerc.net).

*For more information or assistance, please contact Monica Benson,  
Standards Process Administrator, at [monica.benson@nerc.net](mailto:monica.benson@nerc.net) or at 404-446-2560.*

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## Standards Announcement

### Project 2010-07 Generator Requirements at the Transmission Interface

Project 2010-07 Generator Requirements at the Transmission Interface  
Ballot Pool Forming March 2 – 31, 2012  
Formal Comment Period Open March 2 – April 16, 2012  
Initial Ballot Window Open April 6 – 16, 2012

[Available Friday, March 2, 2012](#)

The Generator Requirements at the Transmission Interface drafting team has posted very limited revisions to PRC-005-1a – Transmission and Generation Protection System Maintenance and Testing, along with an implementation plan, for a parallel formal 45-day comment period and initial ballot. Because of the limited nature of the changes, the Standards Committee has authorized waiving the initial 30-day comment period.

Note that more substantive revisions to PRC-005-2 (under Project 2007-17 Protection System Maintenance and Testing) are also posted for a parallel 30-day formal comment period and successive ballot through March 28, 2012. The Project 2010-07 SDT recognizes this and supports the work of that team, whose changes eliminate the need for the surgical addition of “generator interconnection Facility” made in PRC-005-1.1a. Because the Project 2010-07 SDT cannot predict the outcome of Project 2007-17 and wants to ensure that generator interconnection Facilities are appropriately addressed in PRC-005 whether or not PRC-005-2 proceeds to NERC's Board this year, it has elected to continue with its revisions to PRC-005-1.1a.

#### **Instructions for Joining the Ballot Pool for Project 2010-07**

Registered Ballot Body members may join the ballot pool to be eligible to vote in the upcoming ballot of PRC-005-1.1a at the following page: [Join Ballot Pool](#)

During the pre-ballot windows, members of the ballot pool may communicate with one another by using their “ballot pool list server.” (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: [bp-2010-07\\_PRC-005-1.1a\\_in@nerc.com](mailto:bp-2010-07_PRC-005-1.1a_in@nerc.com)

**Instructions for Commenting**

Please use this [electronic form](#) to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at [monica.benson@nerc.net](mailto:monica.benson@nerc.net). An off-line, unofficial copy of the comment form is posted on the [project page](#).

**Special Instructions for Submitting Comments with a Ballot**

Please note that comments submitted during the formal comment period and ballot for the standard all use the same electronic form, and it is NOT necessary for ballot pool members to submit more than one set of comments. The drafting team requests that all stakeholders (ballot pool members as well as other stakeholders) submit all comments through the electronic comment form.

**Next Steps**

An initial ballot of PRC-005-1.1a will begin on Friday, April 6, 2012 and end at 8 p.m. Eastern on Monday, April 16, 2012.

**Background**

The purpose of Project 2010-07 is to ensure that all generator-owned Facilities are appropriately covered under NERC's Reliability Standards. While many Generator Owners and Generator Operators operate Facilities, commonly known as generator interconnection Facilities, that are considered by some entities to be transmission, these are most often radial Facilities that are not part of the integrated grid. As such, they should not be subject to the same standards applicable to Transmission Owners and Transmission Operators who own and operate Transmission Elements and Facilities that are part of the integrated grid.

As part of the BES, generators so affect the overall reliability of the BES. But registering a Generator Owner or Generator Operator as a Transmission Owner or Transmission Operator, as has been the solution in some cases in the past, may decrease reliability by diverting the Generator Owner's or Generator Operator's resources from the operation of the equipment that actually produces electricity – the generation equipment itself.

The drafting team's goal is to ensure that an adequate level of reliability is maintained in the BES by clearly describing which standards need to be applied to generator interconnection Facilities that are not already applicable to Generator Owners or Generator Operators. The SDT believes that properly applying PRC-005-1.1a to Generator Owners as proposed in the redline standard posted for comment supports this objective.

Before reviewing the standards, the drafting team encourages all stakeholders to read the technical justification resource document it has provided to describe its rationale and its work thus far.

Additional information is available on the [project page](#).

### Standards Development Process

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## Standards Announcement

### Project 2010-07 – Generator Requirements at the Transmission Interface

#### Initial Ballot Results

#### [Now Available](#)

An initial ballot of PRC-005-1.1a – Transmission and Generation Protection System Maintenance and Testing standard concluded Monday, April 16, 2012:

Voting statistics for the ballot are listed below, and the [Ballots Results](#) page provides a link to the detailed results.

Standard	Quorum	Approval
PRC-005-1.1a – Transmission and Generation Protection System Maintenance and Testing	88.95 %	92.41%

#### Next Steps

The drafting team will consider all comments received during the formal comment period and initial ballot. If the drafting team decides to make substantive revisions, the drafting team will submit the revised standard and consideration of comments received for a quality review prior to posting for a parallel formal 30-day comment period and successive ballot. If the drafting team determines that no substantive changes are required to be responsive to the comments received, the standard will be posted for a recirculation ballot.

#### Background

The purpose of Project 2010-07 is to ensure that all generator-owned Facilities are appropriately covered under NERC's Reliability Standards. While many Generator Owners and Generator Operators operate Facilities commonly known as generator interconnection Facilities considered by some entities to be Transmission, these are most often radial Facilities that are not part of the integrated grid. As such, they should not be subject to the same standards applicable to Transmission Owners and Transmission Operators who own and operate Transmission Elements and Facilities that are part of the integrated grid.

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Generator Operator's resources from the operation of the equipment that actually produces electricity – the generation equipment itself.

The drafting team's goal is to ensure that an adequate level of reliability is maintained in the BES by clearly describing which standards need to be applied to generator interconnection Facilities that are not already applicable to Generator Owners or Generator Operators. The SDT believes that properly applying PRC-005-1.1a to Generator Owners as proposed supports this objective.

The drafting team encourages all stakeholders to read the technical justification resource document it has provided to describe its rationale and its work thus far.

Additional information is available on the [project page](#).

### **Standards Development Process**

The [Standard Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. For more information or assistance, please contact Monica Benson at [monica.benson@nerc.net](mailto:monica.benson@nerc.net).

*For more information or assistance, please contact Monica Benson,  
Standards Process Administrator, at [monica.benson@nerc.net](mailto:monica.benson@nerc.net) or at 404-446-2560.*

User Name

Password

Log in

Register

- Ballot Pools
- Current Ballots
- Ballot Results
- Registered Ballot Body
- Proxy Voters

Home Page

Ballot Results	
<b>Ballot Name:</b>	Project 2010-07 PRC-005-1.1a
<b>Ballot Period:</b>	4/6/2012 - 4/16/2012
<b>Ballot Type:</b>	Initial
<b>Total # Votes:</b>	346
<b>Total Ballot Pool:</b>	389
<b>Quorum:</b>	<b>88.95 % The Quorum has been reached</b>
<b>Weighted Segment Vote:</b>	92.41 %
<b>Ballot Results:</b>	<b>The drafting team is considering comments.</b>

Summary of Ballot Results									
Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain # Votes	No Vote	
			# Votes	Fraction	# Votes	Fraction			
1 - Segment 1.	102	1	71	0.922	6	0.078	10	15	
2 - Segment 2.	8	0.4	4	0.4	0	0	2	2	
3 - Segment 3.	84	1	63	0.9	7	0.1	8	6	
4 - Segment 4.	28	1	22	0.917	2	0.083	3	1	
5 - Segment 5.	96	1	68	0.895	8	0.105	8	12	
6 - Segment 6.	51	1	34	0.85	6	0.15	6	5	
7 - Segment 7.	0	0	0	0	0	0	0	0	
8 - Segment 8.	9	0.5	5	0.5	0	0	4	0	
9 - Segment 9.	3	0.2	2	0.2	0	0	0	1	
10 - Segment 10.	8	0.7	7	0.7	0	0	0	1	
<b>Totals</b>	<b>389</b>	<b>6.8</b>	<b>276</b>	<b>6.284</b>	<b>29</b>	<b>0.516</b>	<b>41</b>	<b>43</b>	

Individual Ballot Pool Results				
Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	<a href="#">View</a>
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Negative	<a href="#">View</a>
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	

1	Baltimore Gas & Electric Company	Gregory S Miller	<a href="#">Abstain</a>	<a href="#">View</a>
1	BC Hydro and Power Authority	Patricia Robertson	<a href="#">Affirmative</a>	
1	Beaches Energy Services	Joseph S Stonecipher	<a href="#">Affirmative</a>	<a href="#">View</a>
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	<a href="#">Negative</a>	<a href="#">View</a>
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	<a href="#">Affirmative</a>	<a href="#">View</a>
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	<a href="#">Affirmative</a>	
1	Central Electric Power Cooperative	Michael B Bax	<a href="#">Affirmative</a>	<a href="#">View</a>
1	Central Maine Power Company	Joseph Turano Jr.	<a href="#">Affirmative</a>	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	<a href="#">Affirmative</a>	
1	Clark Public Utilities	Jack Stamper	<a href="#">Affirmative</a>	
1	Colorado Springs Utilities	Paul Morland	<a href="#">Affirmative</a>	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	<a href="#">Affirmative</a>	
1	CPS Energy	Richard Castrejana	<a href="#">Affirmative</a>	
1	Dairyland Power Coop.	Robert W. Roddy	<a href="#">Affirmative</a>	
1	Dayton Power & Light Co.	Hertzel Shamash	<a href="#">Affirmative</a>	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	<a href="#">Affirmative</a>	
1	Duke Energy Carolina	Douglas E. Hils		
1	Empire District Electric Co.	Ralph F Meyer	<a href="#">Affirmative</a>	
1	Entergy Services, Inc.	Edward J Davis	<a href="#">Affirmative</a>	
1	FirstEnergy Corp.	William J Smith	<a href="#">Affirmative</a>	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	<a href="#">Affirmative</a>	
1	Florida Power & Light Co.	Mike O'Neil	<a href="#">Affirmative</a>	
1	FortisBC	Curtis Klashinsky		
1	Georgia Transmission Corporation	Jason Snodgrass	<a href="#">Affirmative</a>	
1	Great River Energy	Gordon Pietsch	<a href="#">Affirmative</a>	<a href="#">View</a>
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	<a href="#">Affirmative</a>	
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Ronald D. Schellberg	<a href="#">Affirmative</a>	
1	Imperial Irrigation District	Tino Zaragoza	<a href="#">Affirmative</a>	
1	International Transmission Company Holdings Corp	Michael Moltane	<a href="#">Abstain</a>	
1	JEA	Ted Hobson	<a href="#">Affirmative</a>	
1	KAMO Electric Cooperative	Walter Kenyon	<a href="#">Affirmative</a>	
1	Kansas City Power & Light Co.	Michael Gammon	<a href="#">Negative</a>	<a href="#">View</a>
1	Lakeland Electric	Larry E Watt	<a href="#">Affirmative</a>	
1	Lee County Electric Cooperative	John W Delucca	<a href="#">Abstain</a>	
1	Lincoln Electric System	Doug Bantam	<a href="#">Abstain</a>	
1	Long Island Power Authority	Robert Ganley	<a href="#">Abstain</a>	
1	Los Angeles Department of Water & Power	John Burnett	<a href="#">Affirmative</a>	
1	Lower Colorado River Authority	Martyn Turner	<a href="#">Affirmative</a>	
1	Manitoba Hydro	Joe D Petaski	<a href="#">Negative</a>	<a href="#">View</a>
1	MEAG Power	Danny Dees	<a href="#">Affirmative</a>	
1	Metropolitan Water District of Southern California	Ernest Hahn	<a href="#">Abstain</a>	
1	MidAmerican Energy Co.	Terry Harbour	<a href="#">Affirmative</a>	
1	Minnkota Power Coop. Inc.	Theresa Allard		
1	Muscatine Power & Water	Tim Reed		
1	Nebraska Public Power District	Cole C Brodine	<a href="#">Affirmative</a>	
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	<a href="#">Affirmative</a>	
1	Northeast Missouri Electric Power Cooperative	Kevin White	<a href="#">Affirmative</a>	
1	Northeast Utilities	David Boguslawski		
1	Northern Indiana Public Service Co.	Kevin M Largura	<a href="#">Affirmative</a>	
1	Ohio Valley Electric Corp.	Robert Matthey	<a href="#">Affirmative</a>	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	<a href="#">Abstain</a>	
1	Omaha Public Power District	Doug Peterchuck	<a href="#">Affirmative</a>	
1	Oncor Electric Delivery	Jen Fiegel	<a href="#">Affirmative</a>	
1	Orlando Utilities Commission	Brad Chase	<a href="#">Abstain</a>	
1	Otter Tail Power Company	Daryl Hanson		
1	PacifiCorp	Ryan Millard	<a href="#">Affirmative</a>	
1	PECO Energy	Ronald Schloendorn	<a href="#">Affirmative</a>	
1	Platte River Power Authority	John C. Collins	<a href="#">Affirmative</a>	

1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Brett A Koelsch	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunkel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	<a href="#">View</a>
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	<a href="#">View</a>
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	<a href="#">View</a>
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Negative	<a href="#">View</a>
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen		
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	Alberta Electric System Operator	Mark B Thompson	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Abstain	
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Affirmative	<a href="#">View</a>
3	Alabama Power Company	Richard J. Mandes	Affirmative	<a href="#">View</a>
3	Ameren Services	Mark Peters	Affirmative	
3	APS	Steven Norris	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	<a href="#">View</a>
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	<a href="#">View</a>
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City of Redding	Bill Hughes	Abstain	
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea		
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	Entergy	Joel T Plessinger	Affirmative	

3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Flathead Electric Cooperative	John M Goroski	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Danny Lindsey	Affirmative	<a href="#">View</a>
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	<a href="#">View</a>
3	Gulf Power Company	Paul C Caldwell	Affirmative	<a href="#">View</a>
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz	Affirmative	
3	JEA	Garry Baker		
3	Kansas City Power & Light Co.	Charles Locke	Negative	<a href="#">View</a>
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Norman D Harryhill	Affirmative	
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Daniel D Kurowski		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Negative	<a href="#">View</a>
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Affirmative	<a href="#">View</a>
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Ocala Electric Utility	David Anderson	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	<a href="#">View</a>
3	PacifiCorp	Dan Zollner	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter		
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Benton County	Gloria Bender	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	<a href="#">View</a>
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Abstain	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Negative	<a href="#">View</a>
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Negative	<a href="#">View</a>
4	City of Clewiston	Kevin McCarthy	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Abstain	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	



4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Imperial Irrigation District	Diana U Torres	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Affirmative	
4	LaGen	Richard Comeaux	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	<a href="#">View</a>
4	Modesto Irrigation District	Spencer Tacke	Affirmative	
4	North Carolina Eastern Municipal Power Agency	Cecil Rhodes	Affirmative	
4	Northern California Power Agency	Tracy R Bibb	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	Tacoma Public Utilities	Keith Morissette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	<a href="#">View</a>
5	AES Corporation	Leo Bernier	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Abstain	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	<a href="#">View</a>
5	BP Wind Energy North America Inc	Carla Bayer	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Abstain	<a href="#">View</a>
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	Castleton Energy Center	John Walsh		
5	City and County of San Francisco	Daniel Mason	Negative	<a href="#">View</a>
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	<a href="#">View</a>
5	City of Redding	Paul Cummings	Abstain	
5	Cogentrix Energy, Inc.	Mike D Hirst		
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea	Affirmative	<a href="#">View</a>
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine		
5	Dynergy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Affirmative	
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer	Affirmative	
5	Electric Power Supply Association	John R Cashin	Affirmative	
5	Energy Services, Inc.	Tracey Stubbs	Affirmative	
5	Essential Power, LLC	Patrick Brown	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	First Solar, Inc.	Robert Jenkins		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	GenOn Energy, Inc	James W Mason	Abstain	
5	Great River Energy	Preston L Walsh	Affirmative	<a href="#">View</a>
5	ICF International	Brent B Hebert	Affirmative	
5	Imperial Irrigation District	Marcela Y Caballero	Affirmative	
5	Invenergy LLC	Alan Beckham	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	<a href="#">View</a>

5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom		
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	Manitoba Hydro	S N Fernando	Negative	<a href="#">View</a>
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Affirmative	
5	Muscatine Power & Water	Mike Avesing		
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern California Power Agency	Hari Modi	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson		
5	Occidental Chemical	Michelle R DAntuono	Affirmative	<a href="#">View</a>
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	<a href="#">View</a>
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Gary L Tingley	Abstain	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	Proven Compliance Solutions	Mitchell E Needham	Abstain	
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 1 of Lewis County	Steven Grega	Abstain	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Claire Lloyd	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	TransAlta Corporation	Rebekka McFadden		
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Negative	<a href="#">View</a>
6	AEP Marketing	Edward P. Cox	Affirmative	<a href="#">View</a>
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	RANDY A YOUNG	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	City of Austin dba Austin Energy	Lisa L Martin	Negative	<a href="#">View</a>
6	City of Redding	Marvin Briggs	Abstain	
6	Cleco Power LLC	Robert Hirschak	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Donald Schopp	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	



6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	<a href="#">View</a>
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	<a href="#">View</a>
6	Lakeland Electric	Paul Shipps	Abstain	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	<a href="#">View</a>
6	MidAmerican Energy Co.	Dennis Kimm	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	<a href="#">View</a>
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach		
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	
6	South California Edison Company	Ljuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	<a href="#">View</a>
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tenaska Power Services Co.	John D Varnell		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	David F. Lemmons	Negative	<a href="#">View</a>
8		Brendan Kirby	Abstain	
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Abstain	
8	JDRJC Associates	Jim Cyrulewski	Abstain	
8	JDRJC Associates	Jim Cyrulewski	Abstain	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
8	Volkman Consulting, Inc.	Terry Volkman	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Affirmative	
9	New York State Department of Public Service	Thomas Dvorsky		
10	Midwest Reliability Organization	James D Burley		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	



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**Individual or group. (19 Responses)**  
**Name (12 Responses)**  
**Organization (12 Responses)**  
**Group Name (7 Responses)**  
**Lead Contact (7 Responses)**  
**Contact Organization (7 Responses)**  
**Question 1 (18 Responses)**  
**Question 1 Comments (19 Responses)**  
**Question 2 (18 Responses)**  
**Question 2 Comments (19 Responses)**

Group
Imperial Irrigation District (IID)
Jesus Sammy Alcaraz
IID
Yes
No
Group
Northeast Power Coordinating Council
Guy Zito
Northeast Power Coordinating Council
Yes
No
Individual
Keira Kazmerski
Xcel Energy
No
Xcel Energy does not believe that trying to implement a revision of PRC-005-1 at this point improves the reliability of the grid. There are better means of clarifying the perceived "misperceptions" than drafting a standard revision. This is particularly the case when PRC-005-2 is further along in the process and is also posted for industry comment and ballot. The effort of the GOTO SDT is counterproductive.
No
Individual
Dan Roethemeyer
Dynegy Inc.
Yes
No
Group
Imperial Irrigation District (IID)
Jesus Sammy Alcaraz
IID

Yes
No
Individual
John Bee
Exelon
Yes
The standard language should be clarified to allow for alternative testing programs, agreed upon by both TO and GO, in cases where testing programs do not follow ownership of the equipment for all Component Types so long as all of the protection for the generator interconnection facility is covered.
Individual
Art Salander
HindlePower, Inc
Yes
No
I believe that the requirements as shown in 1-4a - c need to be better clarified as to the actual tasks required. There seems to be no real distinction between Verification and inspection. There is no clear reporting structure and the requirement to substitute Ohmic readings vs. discharge test is not based on any industry reliable standards. since there is much debate in the industry as to the validity of Ohmic testing and it has not been accepted by the IEEE as an acceptable practice I would rather see terms in line with either IEEE standard or manufacturer's recommendations.
Individual
John Seelke
Public Service Enterprise Group
Yes
No
Individual
Martin Kaufman
ExxonMobil Research and Engineering
No
The bulk electric system is contiguous. Therefore, any facility owned by the Generator Owner that is used to connect the Generator Owner's generation facilities to the bulk electric system is already considered a bulk electric system asset and part of the Generator Owner's generation facilities. As stated by in the question above, the addition of the term "or generator interconnection Facility" does not resolve a reliability gap or add any substance to the requirement
Yes
The SDT has utilized two terms in this round of the drafting process whose definitions are subject to interpretation. The terms 'generating station switchyard' and 'generator interconnection Facility' need to be defined to prevent inconsistent enforcement or need for the development of a Compliance Application Notice. As referenced in our comments to FAC-003-X/3, when you try to apply the term 'generating station switchyard' to an industrial complex that contains multiple substations between the GSU and utility interconnection facility (another substation) in order to measure the generator lead line for the 1 mile quota, there are several candidates that appear to fit the criteria.
Group
Southwest Power Pool Standards Development Team
Jonathan Hayes

Southwest Power Pool
No
We would advise the Drafting team to take a look at the FERC OATT to reconcile the term “generator interconnection facility “with Tariff term for the LGIA. This should clarify the point of delineation and there should be no misconception of the language as written.
Yes
This effort seems to be redundant due to the work going on with PRC-005-2. We do not understand why this change is being made and it wasn’t made very clear in the red line changes or in this comment form background.
Individual
Michelle R D’Antuono
Ingleside Cogeneration LP
Yes
Since PRC-005-1 already requires the Generation Owner to maintain and test all their BES Protection System components, it seems to Ingleside Cogeneration LP that the need to specify those which may trip the interconnection facility as redundant. However, we do not believe that the Standard Development Team’s modifications materially change the intent of the Standard – nor can they lead an audit team to assign a double violation for a single incidence of non-compliance.
No
Individual
Dale Fredrickson
We Energies
Yes
No
Individual
Michael Falvo
Independent Electricity System Operator
Yes
The proposed implementation plan conflicts with Ontario regulatory practice respecting the effective date of the standard. It is suggested that this conflict be removed by appending to the implementation plan wording, after “applicable regulatory approval” in the Effective Dates Section A5 of the draft standard and P. 1 of the Implementation Plan, to the following effect: “, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.”
Group
Bonneville Power Administration
Chris Higgins
Transmission Reliability Program
Yes
Yes
Regarding Section 1.3 Data Retention, BPA believes that it would be difficult for an entity to provide “other evidence” to demonstrate compliance when the data retention period is shorter than the time since the last audit. BPA requests the drafting team to offer guidance as to what “other evidence” could be provided other than what is already described in the measures. BPA believes that suggesting there is some “other evidence” without providing a description leaves the TO’s and GO’s without clear direction on how to comply with the standard. BPA suggests the data retention period should be three years or since the time the last audit occurred, whichever is longer for each TO and GO to retain

evidence. Should the drafting team revise the Data Retention language to reflect BPA's concerns, BPA would vote in favor of PRC-005-1.1a.

Individual

Joe Petaski

Manitoba Hydro

Yes

No

Manitoba Hydro does not support the changes being proposed in Project 2010-07 in general. If a Generator Owner is required to register as a TO, all the Requirements applicable to a TO should apply. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. For additional information, please see Manitoba Hydro's comments submitted in the comment period ending November 18, 2011. Manitoba Hydro does not believe that the SDT fully addressed our concerns in their responses to our comments in that commenting period.

Individual

Thad Ness

American Electric Power

Yes

Yes

While we support changing the standard requirements as proposed, AEP offers the following comments and suggestions. While the implementation plans states that "there was no reliability gap in the previous version of the standard", the previous version of the standard, if applied literally, does indeed contain a reliability gap in that it does not require Generation Owners that own a transmission Protection System to have a Protection System maintenance and testing program. It is AEP's understanding that referring to the proposed revision as "PRC-005-1.1a" implies errata from PRC-005-1a, and the announcement refers to "very limited revisions". If there is indeed a gap of responsibility in this standard, any changes to remediate such a gap would not be errata, regardless of the amount of proposed changes in content. As such, we recommend that the drafting team use a full revision naming convention for these proposed changes, i.e. PRC-005-2. In addition, making these changes immediately effective would allow no opportunity for an entity to take the proper steps to become compliant. We believe the revision should include an implementation plan that allows industry adequate time to analyze their system and complete any additionally required maintenance and testing activities.

Group

Dominion- NERC Compliance Policy

Mike Garton

Dominion

Yes

No

Group

ACES Power Marketing Standards Collaborators

Jean Nitz

ACES Power Marketing

Yes

Yes

The Implementation Plan for PRC-005-1.1a should be updated to reflect the retirement of currently effective PRC-005-1b instead of PRC-005-1a. PRC-005-1b became effective on March 14, 2012

replacing PRC-005-1a.
Individual
Darryl Curtis
Oncor Electric Delivery Company
Yes
No

# Consideration of Comments

## Generator Requirements at the Transmission Interface Project 2010-07: PRC-005-1.1a

The GOTO Drafting Team thanks all commenters who submitted comments on the first formal posting for PRC-005-1.1a, part of Project 2010-07—Generator Requirements at the Transmission Interface. Overwhelmingly, commenters approved the standard as written, and the team appreciates that support. These standards were posted for a 45-day public comment period from March 2, 2012 through April 16, 2012. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 19 sets of comments, including comments from approximately 65 different people from approximately 38 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

A few commenters did not support the use of the term “generator interconnection Facility” without a formal definition. Based on comments received elsewhere in this project, the SDT has avoided the creation of new NERC glossary terms, and has received significant industry support for that strategy. While it is possible that other language could have been used, the SDT believes the reference “generator interconnection Facility” is clear.

Some commenters are concerned about the changes proposed in PRC-005-1.1a given the fact that PRC-005-2 is also being revised. PRC-005-2 does not have the same issues as PRC-005-1, so no additional changes are needed to that standard to incorporate generator interconnection Facilities, but in case PRC-005-2 does not proceed to NERC’s Board of Trustees, the SDT wants to ensure that the generator interconnection Facility is covered.

Some commenters were concerned about the language in the Data Retention section of the standard. That portion of the standard was modified by NERC staff during the quality review to add boilerplate compliance language recently approved by NERC legal staff. Modifying it further is outside the scope of this SDT.

Some commenters pointed out that PRC-005-1b was approved by FERC on March 14, 2012, replacing PRC-005-1a. As noted in the text box above, going forward, all references to PRC-005-1.1a will be changed to refer to PRC-005-1.1b.

**Note:** PRC-005-1b was approved by FERC on March 14, 2012. Thus, the changes the SDT proposes will be applied to that version of the standard. To reduce confusion, the SDT’s modified standard is still referred to as PRC-005-1.1a below, but all other documents going forward will be appropriately updated to reference PRC-005-1.1b and incorporate the associated interpretation.



Some commenters stated that the addition of “generator interconnection Facility” was unnecessary because that Facility is already considered part of the Generator Owner’s assets. While the SDT believes that Generator Owners do treat the generator interconnection Facility as one of their assets, commenters in previous postings suggested that adding “generator interconnection Facility” could add clarity to the specific language in PRC-004 and PRC-005. It was pointed out to the SDT that language in the requirements of PRC-004 and PRC-005 differed from PRC-001-1, so if the requirements were applied literally, there was the possibility for the misperception that the Generator Owner was only responsible for analyzing its generator Protection Systems, exclusive of its generator interconnection Facility Protection Systems under PRC-004 and PRC-005 (whereas this interpretation wasn’t a risk under PRC-001).

PRC-001-1 used language that had more a more broad application as noted below:

- R1 – “...shall be familiar with the purpose and limitations of protection system schemes applied in its area.”
- R2 – “...shall notify reliability entities of relay or equipment failures as follows...”
- R3 “...shall coordinate new protective systems and changes as follows...”

PRC-004-2a and PRC-005-1b originally used language which could be construed as being more restrictive (as shown below):

- PRC-004-2a@R2 – “The Generator Owner shall analyze its generator Protection System Misoperations...”
- PRC-005-1b@R1 – “...each Generator Owner that owns a generation Protection System...”
- PRC-005-1b@R2 – “...each Generator Owner that owns a generation Protection System...”

The SDT agreed with the comments and modified the standards accordingly.

Other minority comments are addressed alongside their specific comments below.

The SDT considered all stakeholder comments submitted and determined that, save for the update to reference PRC-005-1.1b instead of PRC-005-1.1a, no additional changes are necessary. The standard will be posted for a recirculation ballot.

All comments submitted may be reviewed in their original format on the standard’s project page:

[http://www.nerc.com/filez/standards/Project2010-07\\_GOTO\\_Project.html](http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html)

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission,

you can contact the Vice President of Standards and Training, Herb Schrayshuen, at 404-446-2560 or at [herb.schrayshuen@nerc.net](mailto:herb.schrayshuen@nerc.net). In addition, there is a NERC Reliability Standards Appeals Process.<sup>1</sup>

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<sup>1</sup> The appeals process is in the Reliability Standards Development Procedures: <http://www.nerc.com/standards/newstandardsprocess.html>.

**Index to Questions, Comments, and Responses**

- 1. Based on stakeholder comment, the SDT inserted the phrase “or generator interconnection Facility” in Requirements R1 and R2 of PRC-005-1.1a. While there was no reliability gap in the previous version of the standard, if the Requirements were applied literally, there was the possibility for the misperception that the Generator Owner was only responsible for analyzing its generator Protection Systems, exclusive of its generator interconnection Facility Protection Systems. The clarifying changes to R1 and R2 make clear that generator interconnection Facilities are also part of Generator Owners’ responsibility in the context of this standard. Do you support the addition of the phrase “or generator interconnection Facility” to accomplish this clarification? ..... 9
- 2. Do you have any other comments that you have not yet addressed? If yes, please explain. .... 13

**The Industry Segments are:**

- 1 — Transmission Owners
- 2 — RTOs, ISOs
- 3 — Load-serving Entities
- 4 — Transmission-dependent Utilities
- 5 — Electric Generators
- 6 — Electricity Brokers, Aggregators, and Marketers
- 7 — Large Electricity End Users
- 8 — Small Electricity End Users
- 9 — Federal, State, Provincial Regulatory or other Government Entities
- 10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment										
				1	2	3	4	5	6	7	8	9	10	
1.	Group	Jesus Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X					X
<b>Additional Member Additional Organization Region Segment Selection</b>														
1.	Jose Landeros	IID	WECC	1, 3, 4, 5, 6										
2.	Epi Martinez	IID	WECC	1, 3, 4, 5, 6										
2.	Group	Guy Zito	Northeast Power Coordinating Council											
<b>Additional Member Additional Organization Region Segment Selection</b>														
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10										
2.	Greg Campoli	New York Independent System Operator	NPCC	2										
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1										
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1										
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10										

Group/Individual	Commenter	Organization	Registered Ballot Body Segment																	
			1	2	3	4	5	6	7	8	9	10								
6.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5																
7.	Kathleen Goodman	ISO - New England	NPCC	2																
8.	Chantel Haswell	FPL Group, Inc.	NPCC	5																
9.	David Kiguel	Hydro One Networks Inc.	NPCC	1																
10.	Michael R. Lombardi	Northeast Utilities	NPCC	1																
11.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9																
12.	Bruce Metruck	New York Power Authority	NPCC	6																
13.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10																
14.	Robert Pellegrini	The United Illuminating Company	NPCC	1																
15.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1																
16.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5																
17.	Brian Robinson	Utility Services	NPCC	8																
18.	Saurabh Saksena	National Grid	NPCC	1																
19.	Michael Schiavone	National Grid	NPCC	1																
20.	Wayne Sipperly	New York Power Authority	NPCC	5																
21.	Tina Teng	Independent Electricity System Operator	NPCC	2																
22.	Donald Weaver	New Brunswick System Operator	NPCC	2																
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1																
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.		3																
3.	Group	Jonathan Hayes	Southwest Power Pool Standards Development Team		X	X	X		X	X										
	<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>																
1.	Jonathan Hayes	Southwest Power Pool	SPP	NA																
2.	Robert Rhodes	Southwest Power Pool	SPP	NA																
3.	Dan Lusk	Xcel Energy	SPP	1, 3, 5, 6																
4.	Julie Lux	Westar	SPP	1, 3, 5, 6																
5.	Mahmood Safi	OPPD	MRO	1, 3, 5																
6.	Roy Boyer	Xcel Energy	SPP	1, 3, 5, 6																
7.	Mitchell Williams	Western Farmers	SPP	1, 3, 5																
8.	John Pasierb	East Texas	NA - Not Applicable	NA																
9.	David Kral	Xcel Energy	SPP	1, 3, 5, 6																
10.	Tom Hesterman	Westar	SPP	1, 3, 5, 6																

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
11.	Tiffani Lake	Westar	SPP	6, 1, 3, 5									
12.	Don Taylor	Westar	SPP	1, 3, 5, 6									
4.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				
<b>Additional Member Additional Organization Region Segment Selection</b>													
1.	Dean	Bender	WECC	1									
5.	Group	Mike Garton	Dominion- NERC Compliance Policy	X		X		X	X				
<b>Additional Member Additional Organization Region Segment Selection</b>													
1.	Connie Lowe	NERC Compliance Policy	RFC	6									
2.	Louis Slade	NERC Compliance Policy	SERC	5									
3.	Michael Crowley	Electric Transmission	SERC	1, 3									
4.	Sean Iseminger	Fossil & Hydro	SERC	6									
5.	Chip Humphrey	Fossil & Hydro	NPCC	6									
6.	Jeff Bailey	Nuclear	MRO	6									
6.	Group	Jean Nitz	ACES Power Marketing Standards Collaborators	X		X	X	X	X				
<b>Additional Member Additional Organization Region Segment Selection</b>													
1.	Mohan Sachdeva	Buckeye Power, Inc	RFC	3, 4									
2.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5									
3.	Clem Cassmeyer	Western Farmers Electric Cooperative	SPP	1, 5									
7.	Individual	Keira Kazmerski	Xcel Energy	X		X		X	X				
8.	Individual	Dan Roethemeyer	Dynegy Inc.					X					
9.	Individual	John Bee	Exelon	X		X		X	X				
10.	Individual	Art Salander	HindlePower, Inc										
11.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
12.	Individual	Martin Kaufman	ExxonMobil Research and Engineering	X				X					
13.	Individual	Michelle R D'Antuono	Ingleside Cogeneration LP					X					
14.	Individual	Dale Fredrickson	We Energies			X	X	X					
15.	Individual	Michael Falvo	Independent Electricity System Operator		X								
16.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment										
				1	2	3	4	5	6	7	8	9	10	
17.	Individual	Thad Ness	American Electric Power	X		X		X	X					
18.	Individual	Darryl Curtis	Oncor Electric Delivery Company	X										
19.	Individual	Will Smith	MRO NSRF											

1. **Based on stakeholder comment, the SDT inserted the phrase “or generator interconnection Facility” in Requirements R1 and R2 of PRC-005-1.1a. While there was no reliability gap in the previous version of the standard, if the Requirements were applied literally, there was the possibility for the misperception that the Generator Owner was only responsible for analyzing its generator Protection Systems, exclusive of its generator interconnection Facility Protection Systems. The clarifying changes to R1 and R2 make clear that generator interconnection Facilities are also part of Generator Owners’ responsibility in the context of this standard. Do you support the addition of the phrase “or generator interconnection Facility” to accomplish this clarification?**

#### Summary Consideration:

The SDT thanks all commenters for their feedback on the proposed changes to PRC-005-1.1a. Over 90% of commenters approved the standard as written, and the team appreciates that support.

A few commenters did not support the use of the term “generator interconnection Facility” without a formal definition. Based on comments received elsewhere in this project, the SDT has avoided the creation of new NERC glossary terms, and has received significant industry support for that strategy. While it is possible that other language could have been used, the SDT believes “generator interconnection Facility” is clear, and no changes were made.

One commenter stated that the addition of “generator interconnection Facility” was unnecessary and complicates the ongoing development of PRC-005-2. The SDT believes that the clarifying language is necessary, and points out that if PRC-005-1.1a proceeds to recirculation ballot next as planned, it will actually be slightly ahead of the PRC-005-2 work, because the drafting team working on PRC-005-2 is still reviewing stakeholder comments from a successive ballot that ended March 28, 2012.

One commenter stated that the addition of “generator interconnection Facility” was unnecessary because that Facility is already considered part of the Generator Owner’s assets. While the SDT believes that Generator Owners do treat the generator interconnection Facility as one of their assets, some commenters in previous postings suggested that adding “generator interconnection Facility” could add clarity to the specific language in PRC-004 and PRC-005. The SDT agreed and incorporated that language prior to the last posting.

The SDT considered all of these comments and determined that, save for the update to reference PRC-005-1.1b instead of PRC-005-1.1a, no additional changes are necessary.



Organization	Yes or No	Question 1 Comment
Southwest Power Pool Standards Development Team	No	We would advise the Drafting team to take a look at the FERC OATT to reconcile the term “generator interconnection facility “with Tariff term for the LGIA. This should clarify the point of delineation and there should be no misconception of the language as written.
<p><b>Response:</b> Thank you for the comment. As recommended by stakeholders throughout this project, the SDT has avoided creation of new terms. No change made.</p>		
Xcel Energy	No	Xcel Energy does not believe that trying to implement a revision of PRC-005-1 at this point improves the reliability of the grid. There are better means of clarifying the perceived “misperceptions” than drafting a standard revision. This is particularly the case when PRC-005-2 is further along in the process and is also posted for industry comment and ballot. The effort of the GOTO SDT is counterproductive.
<p><b>Response:</b> Thank you for your comment. The SDT revised the standard based upon comments it received suggesting that it do so. We do agree that there may have been alternative means to address the issue, such as a request for interpretation or CAN, but given this was in the scope of the SAR, the SDT modified the standard to add the clarity recommended. If PRC-005-1.1a proceeds to recirculation ballot next as planned, it will actually be slightly ahead of the PRC-005-2 work, because the drafting team working on PRC-005-2 is still reviewing stakeholder comments from a successive ballot that ended March 28, 2012.</p>		
ExxonMobil Research and Engineering	No	The bulk electric system is contiguous. Therefore, any facility owned by the Generator Owner that is used to connect the Generator Owner’s generation facilities to the bulk electric system is already considered a bulk electric system asset and part of the Generator Owner’s generation facilities. As stated by in the question above, the addition of the term “or generator interconnection Facility” does not resolve a reliability gap or add any substance to the requirement
<p><b>Response:</b> Thank you for your comment. The SDT added the language to add clarity. As we cited above, while there was no reliability gap in the previous version of the standard, if the Requirements were applied literally, there was the possibility for the</p>		

Organization	Yes or No	Question 1 Comment
<p>misperception that the Generator Owner was only responsible for analyzing its generator Protection Systems, exclusive of its generator interconnection Facility Protection Systems. We believe that the clarifying change is useful.</p>		
<p>Kansas City Power &amp; Light (<b>Note: Comment was manually added</b>)</p>	<p>No</p>	<p>The phrase “generator interconnection” facility lacks definition making it difficult to comment on the proposed change. It is important for the standards and requirements to clearly delineate, define, or identify the facilities or operating condition subject to application of the standards and requirements.</p>
<p><b>Response:</b> Thank you for your comment. As recommended by stakeholders throughout this project, the SDT has avoided creation of new terms. No change made.</p>		
<p>Ingleside Cogeneration LP</p>	<p>Yes</p>	<p>Since PRC-005-1 already requires the Generation Owner to maintain and test all their BES Protection System components, it seems to Ingleside Cogeneration LP that the need to specify those which may trip the interconnection facility as redundant. However, we do not believe that the Standard Development Team’s modifications materially change the intent of the Standard - nor can they lead an audit team to assign a double violation for a single incidence of non-compliance.</p>
<p><b>Response:</b> Thank you for your comment. The SDT added the language to add clarity. As we cited above, while there was no reliability gap in the previous version of the standard, if the Requirements were applied literally, there was the possibility for the misperception that the Generator Owner was only responsible for analyzing its generator Protection Systems, exclusive of its generator interconnection Facility Protection Systems. We believe that the clarifying change is useful.</p>		
<p>Imperial Irrigation District (IID)</p>	<p>Yes</p>	
<p>Northeast Power Coordinating Council</p>	<p>Yes</p>	
<p>Imperial Irrigation District (IID)</p>	<p>Yes</p>	

Organization	Yes or No	Question 1 Comment
Bonneville Power Administration	Yes	
Dominion- NERC Compliance Policy	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Dynegy Inc.	Yes	
HindlePower, Inc	Yes	
Public Service Enterprise Group	Yes	
We Energies	Yes	
Independent Electricity System Operator	Yes	
Manitoba Hydro	Yes	
American Electric Power	Yes	
Oncor Electric Delivery Company	Yes	

## 2. Do you have any other comments that you have not yet addressed? If yes, please explain.

### Summary Consideration:

The SDT thanks all commenters for their feedback on the proposed changes to PRC-005-1.1a. Overwhelmingly, commenters approved of the standard as written, and the team appreciates that support.

Some commenters are concerned about the changes proposed in PRC-005-1.1a given the fact that PRC-005-2 is also being revised. PRC-005-2 does not have the same issues as PRC-005-1, so no additional changes are needed to that standard to incorporate generator interconnection Facilities, but in case PRC-005-2 does not proceed to NERC's Board of Trustees, the SDT wants to ensure that the generator interconnection Facility is covered.

Some commenters were concerned about the language in the Data Retention section of the standard. That portion of the standard was modified by NERC staff during the quality review to add boilerplate compliance language recently approved by NERC legal staff. Modifying it further is outside the scope of this SDT.

Some commenters pointed out that PRC-005-1b was approved by FERC on March 14, 2012, replacing PRC-005-1a. Going forward, all references to PRC-005-1.1a will be changed to refer to PRC-005-1.1b.

Some commenters did not support the use of the term "generator interconnection Facility" without a formal definition. Based on comments received elsewhere in this project, the SDT has avoided the creation of new NERC glossary terms, and has received significant industry support for that strategy. While it is possible that other language could have been used, the SDT believes "generator interconnection Facility" is clear, and no changes were made.

One commenter was concerned that the addressing of a literal "reliability gap" should not be considered an errata change. The SDT maintains that there is no actual reliability gap in the current standard language – just the possible perception of one. The SDT and most stakeholders still believe that the clarifying change is a useful one, but it is appropriate to classify as a minor change because it does not change the scope or intent of the associated standard. Still, the SDT agrees that the errata label is confusing, as errata changes do not require a ballot. The SDT will no longer refer to its changes as errata.

One commenter was concerned that the standard as written does not allow for alternative testing programs in cases where testing programs do not follow the ownership of the equipment. The SDT points out that an entity can enter into an agreement (including a Coordinated Functional Registration) whereby another entity is assigned responsibility for compliance with one or more requirements of one or more reliability standards without the standard itself being so modified. The SDT therefore does not agree that this standard should be explicitly modified to allow what the commenter suggests.

One commenter was concerned about the statement that “no changes” were made to the VSLs. Because the SDT has not proposed changes that affect the scope or intent of the current standard, no changes to the VSLs were necessary. The same VSLs that have been approved by FERC (which can be found in the VSL matrix posted on NERC’s website: <http://www.nerc.com/page.php?cid=2|20|288>) will remain in effect.

One commenter stated that the addition of “generator interconnection Facility” was unnecessary because that Facility is already considered part of the Generator Owner’s assets. While the SDT believes that Generator Owners do treat the generator interconnection Facility as one of their assets, some commenters in previous postings suggested that adding “generator interconnection Facility” could add clarity to the specific language in PRC-004 and PRC-005. The SDT agreed and modified the standards accordingly.

One commenter continues to find the changes proposed under Project 2010-07 to be unnecessary. As it has in previously consideration of comment reports, the SDT points out that it must act within the scope of the SAR for this project. As mandated by its SAR, the SDT has addressed standards for which there is a reliability gap or possible perception of a gap when it comes to the generator interconnection Facility, as justified in great depth in its [Technical Justification document](#).

One commenter encouraged the SDT to update the Effective Dates and Implementation Dates language to incorporate the latest NERC legal boilerplate language. That change has been made.

The SDT considered all of these comments and determined that, save for the update to reference PRC-005-1.1b instead of PRC-005-1.1a, no additional changes are necessary.

Organization	Yes or No	Question 2 Comment
Baltimore Gas & Electric Company	Abstain	Please refer to comments submitted by Exelon.
Southwest Power Pool Standards Development Team	Yes	This effort seems to be redundant due to the work going on with PRC-005-2. We do not understand why this change is being made and it wasn’t made very clear in the red line changes or in this comment form background.
<p><b>Response:</b> Thank you for your comment. The Project 2007-17 Protection System Maintenance and Testing SDT is working on comprehensive changes to PRC-005, as described in detail in the SAR posted on that projects webpage, while the Project 2010-07</p>		

Organization	Yes or No	Question 2 Comment
<p>Generator Requirements at the Transmission Interface SDT is focused on making surgical revisions to standards where there might be a reliability gap related to generator-owned Transmission Facilities. The current draft of PRC-005-2 does not have the same issues as PRC-005-1 with respect to generator-owned Facilities, so no additional changes are needed to that standard to incorporate generator interconnection Facilities, but in case PRC-005-2 does not proceed to NERC’s BOT, the Project 2010-07 SDT wants to ensure that the generator interconnection Facility is covered.</p>		
<p>Bonneville Power Administration</p>	<p>Yes</p>	<p>Regarding Section 1.3 Data Retention, BPA believes that it would be difficult for an entity to provide “other evidence” to demonstrate compliance when the data retention period is shorter than the time since the last audit. BPA requests the drafting team to offer guidance as to what "other evidence" could be provided other than what is already described in the measures. BPA believes that suggesting there is some “other evidence” without providing a description leaves the TO’s and GO’s without clear direction on how to comply with the standard. BPA suggests the data retention period should be three years or since the time the last audit occurred, whichever is longer for each TO and GO to retain evidence. Should the drafting team revise the Data Retention language to reflect BPA’s concerns, BPA would vote in favor of PRC-005-1.1a.</p>
<p><b>Response:</b> Thank you for your comment. This section was revised by NERC staff to add boilerplate compliance language recently approved by NERC legal staff. Thus, it is outside the scope of the SDT and no change was made.</p>		
<p>ACES Power Marketing Standards Collaborators</p>	<p>Yes</p>	<p>The Implementation Plan for PRC-005-1.1a should be updated to reflect the retirement of currently effective PRC-005-1b instead of PRC-005-1a. PRC-005-1b became effective on March 14, 2012 replacing PRC-005-1a.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees with the comment and has made the suggested changes.</p>		
<p>Exelon</p>	<p>Yes</p>	<p>The standard language should be clarified to allow for alternative testing programs, agreed upon by both TO and GO, in cases where testing programs do not follow ownership of the equipment for all Component Types so long as all of the protection for the generator interconnection facility is covered.</p>

Organization	Yes or No	Question 2 Comment
<p><b>Response:</b> Thank you for your comment. An entity can enter into an agreement (including a Coordinated Functional Registry) whereby another entity is assigned responsibility for compliance with one or more requirements of one or more reliability standards without the standard itself being so modified. The SDT therefore does not agree that this standard should be explicitly modified to allow this. No change made.</p>		
ExxonMobil Research and Engineering	Yes	<p>The SDT has utilized two terms in this round of the drafting process whose definitions are subject to interpretation. The terms ‘generating station switchyard’ and ‘generator interconnection Facility’ need to be defined to prevent inconsistent enforcement or need for the development of a Compliance Application Notice. As referenced in our comments to FAC-003-X/3, when you try to apply the term ‘generating station switchyard’ to an industrial complex that contains multiple substations between the GSU and utility interconnection facility (another substation) in order to measure the generator lead line for the 1 mile quota, there are several candidates that appear to fit the criteria.</p>
<p><b>Response:</b> Thank you for your comment. As recommended by stakeholders throughout this project, the SDT has avoided creation of new NERC glossary terms. While the SDT concedes there may be other language that could be used, the language posted has wide industry support, therefore no change will be made.</p>		
American Electric Power	Yes	<p>While we support changing the standard requirements as proposed, AEP offers the following comments and suggestions. While the implementation plans states that “there was no reliability gap in the previous version of the standard”, the previous version of the standard, if applied literally, does indeed contain a reliability gap in that it does not require Generation Owners that own a transmission Protection System to have a Protection System maintenance and testing program. It is AEP’s understanding that referring to the proposed revision as “PRC-005-1.1a” implies errata from PRC-005-1a, and the announcement refers to “very limited revisions”. If there is indeed a gap of responsibility in this standard, any changes to remediate such a gap would not be errata, regardless of the amount of proposed changes in content. As such, we recommend that the drafting team use a full revision naming</p>

Organization	Yes or No	Question 2 Comment
		<p>convention for these proposed changes, i.e. PRC-005-2. In addition, making these changes immediately effective would allow no opportunity for an entity to take the proper steps to become compliant. We believe the revision should include an implementation plan that allows industry adequate time to analyze their system and complete any additionally required maintenance and testing activities.</p>
<p><b>Response:</b> Thank you for your comment. The SDT added the language to add clarity. As we cited above, while there was no reliability gap in the previous version of the standard, if the Requirements were applied literally, there was the possibility for the misperception that the Generator Owner was only responsible for analyzing its generator Protection Systems, exclusive of its generator interconnection Facility Protection Systems. We believe that the clarifying change is a useful one, but it is appropriate to classify as a minor change because it does not change the scope or intent of the associated standard. Regarding the naming convention, the SDT was advised that the errata naming convention would be acceptable to avoid confusion with the more complete set of revisions to PRC-005 that are underway in Project 2007-17. The SDT had previously used the word “errata” to describe its changes, but agrees that the errata label is confusing, as errata changes do not require a ballot. The SDT will no longer refer to its changes as errata. No change made.</p>		
<p>Southern Illinois Power Coop., Brazos Electric Power Cooperative, Inc.</p>	<p>Affirmative</p>	<p>The Implementation Plan for PRC-005-1.1a should be updated to reflect the retirement of currently effective PRC-005-1b instead of PRC-005-1a. PRC-005-1b became effective on March 14, 2012 replacing PRC-005-1a.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees with the comment and has made the suggested changes.</p>		
<p>Pacific Gas and Electric Company</p>	<p>Affirmative</p>	<p>The data retention period identified in D1.3 cannot be shorter than the time between audits or the prior maintenance and testing interval</p>
<p><b>Response:</b> Thank you for your comment. This section was revised by NERC staff to add boilerplate compliance language recently approved by NERC legal staff. Thus, it is outside the scope of the SDT and no change was made.</p>		
<p>AEP Service Corp., AEP and AEP Marketing, American Electric Power</p>	<p>Affirmative</p>	<p>Comments are being submitted via electronic form by Thad Ness on behalf of American Electric Power</p>



Organization	Yes or No	Question 2 Comment
Great River Energy	Affirmative	Great River Energy agrees with the comments of the MRO NSRF.
Dairyland Power Coop.	Affirmative	Please see comments submitted by MRO NSRF.
Muscatine Power & Water	Affirmative	Please see comments submitted by the MRO NERC Standards Review Forum
Madison Gas and Electric Co.	Affirmative	Please see MRO NSRF comments.
Omaha Public Power District	Affirmative	Please see MRO NSRF Comments.
Brazos Electric Power Cooperative, Inc.	Affirmative	See ACES Power Marketing comments.
Occidental Chemical	Affirmative	See comments submitted by Ingleside Cogeneration LP
Central Electric Power Cooperative	Affirmative	See Matt Pacobit's comments from AECl
Southern Company Services, Inc.	Affirmative	None
Alabama Power Company	Affirmative	None
Georgia Power Company	Affirmative	None
Gulf Power Company	Affirmative	None
Mississippi Power	Affirmative	None
Southern Company Generation and Energy	Affirmative	None

Organization	Yes or No	Question 2 Comment
Marketing		
Beaches Energy Services	Affirmative	(No Comments.)
Independent Electricity System Operator		The proposed implementation plan conflicts with Ontario regulatory practice respecting the effective date of the standard. It is suggested that this conflict be removed by appending to the implementation plan wording, after “applicable regulatory approval” in the Effective Dates Section A5 of the draft standard and P. 1 of the Implementation Plan, to the following effect:”, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.”
<p><b>Response:</b> Thank you for your comment. The language you cite has been approved by NERC legal and has been updated in the Effective Dates section and in the Implementation Plan.</p>		
Sunflower Electric Power Corporation	Negative	A new term is introduced that is not a NERC defined term, the term is generator interconnection Facility. The term was inserted without comment and clearly is intended to include something that is not covered by the Standard. This new term should be removed or defined in Glossary of Terms so entities may understand just what is covered by this new term. The Implementation Plan for PRC-005-1.1a should be updated to reflect the retirement of currently effective PRC-005-1b instead of PRC-005-1a. PRC-005-1b became effective on March 14, 2012 replacing PRC-005-1a.
<p><b>Response:</b> Thank you for your comment. As recommended by stakeholders throughout this project, the SDT has avoided creation of new NERC glossary terms. The SDT purposefully did not create a new term (note that only Facility is capitalized, while generator and interconnection are not). No change made.</p>		
Seminole Electric Cooperative, Inc.	Negative	a) Section D.2 Violation Severity Levels (no changes) - The standard should stand on its own, therefore, just stating that the VSLs have "(no changes)" is incomplete and will lead to confusion. Please provide definition and clarity to this section.
<p><b>Response:</b> Thank you for your comment. The SDT has not proposed changes that affect the scope or intent of the current standard,</p>		

Organization	Yes or No	Question 2 Comment
<p>and because of that, no changes to the VSLs are necessary. The same VSLs that have been approved by FERC (which can be found in the VSL matrix posted on NERC’s website: <a href="http://www.nerc.com/page.php?cid=2 20 288">http://www.nerc.com/page.php?cid=2 20 288</a>) will remain in effect. No change made.</p>		
<p>Austin Energy, City of Austin dba Austin Energy</p>	<p>Negative</p>	<p>Adding the words "generator interconnection" to the Facility description does not add clarity to the Standard. PRC-005-1 is clear as written, indicating the actual owner of a device supporting the BES is responsible for performing the actions necessary to comply with PRC-005. The term "generator interconnection" is not defined and introduces confusion, making responsibility for the application of the Requirements less clear.</p>
<p><b>Response:</b> Thank you for your comment. The SDT added the language to add clarity. As we cited above, while there was no reliability gap in the previous version of the standard, if the Requirements were applied literally, there was the possibility for the misperception that the Generator Owner was only responsible for analyzing its generator Protection Systems, exclusive of its generator interconnection Facility Protection Systems. We believe that the clarifying change is useful. No change made.</p>		
<p>Kansas City Power &amp; Light Co.</p>	<p>Negative</p>	<p>Concerns have been expressed in the Standard comment forms provided by NERC.</p>
<p>Tucson Electric Power Co.</p>	<p>Negative</p>	<p>It would be difficult for an entity to provide "other evidence" to demonstrate compliance when the data retention period is shorter than the time since the last audit. Suggest that the data retention period language should be modified to "three years or since the time the last audit occurred, whichever is longer"</p>
<p><b>Response:</b> Thank you for your comment. This section was revised by NERC staff to add boilerplate compliance language recently approved by NERC legal staff. Thus, it is outside the scope of the SDT and no change was made.</p>		
<p>Bonneville Power Administration</p>	<p>Negative</p>	<p>Please refer to BPA's comments submitted separately.</p>
<p>Manitoba Hydro</p>	<p>Negative</p>	<p>Please see comments submitted by Joe Petaski (Manitoba Hydro)</p>
<p>Xcel Energy, Inc.</p>	<p>Negative</p>	<p>Xcel Energy sees this project as counter-productive to the efforts of the Protection</p>

Organization	Yes or No	Question 2 Comment
		System Maintenance and Testing Standard Drafting Team that currently has PRC-005-2 posted for comment and successive ballot.
<p><b>Response:</b> Thank you for your comment. PRC-005-2 does not have the same issues as PRC-005-1, so no additional changes are needed to that standard to incorporate generator interconnection Facilities, but in case PRC-005-2 does not proceed to NERC’s BOT, we want to ensure that the generator interconnection Facility is covered.</p>		
City and County of San Francisco	Negative	This revision should be used as an opportunity to clean up language relating to the data retention period for PRC-005. The following language has been suggested and appears consistent with the actual data retention period needed for all functional registrations encompassed by this Standard: "three years or since the time the last audit occurred, whichever is longer"
<p><b>Response:</b> Thank you for your comment. This section was revised by NERC staff to add boilerplate compliance language recently approved by NERC legal staff. Other changes are outside the scope of the SDT.</p>		
HindlePower, Inc	No	I beleive that the requirments as shown in 1-4a - c need to be better clarified as to the actual tasks required. There seems to be no real distinction between Verification and inspection. There is no clear reporting structure and the requirment to substitute Ohmic readings vs. discharge test is not basede on any industry reliable standards. since there is much debate in the industry as to the validity if Ohmic testing and it has not been accepted by the IEEE as an acceptbale practice I would rather see terms in line with either IEEE standard or manufacvturer's recommendations.
<p><b>Response:</b> Thank you for your comment. The SDT believes these comments may have been intended for the Project 2007-17 drafting team which is making comprehensive revisions to PRC-005-2. The comment will be forwarded to that team by NERC staff.</p>		
Manitoba Hydro	No	Manitoba Hydro does not support the changes being proposed in Project2010-07 in general. If a Generator Owner is required to register as a TO, all theRequirements applicable to a TO should apply. There is no need to changespecific Reliability

Organization	Yes or No	Question 2 Comment
		<p>Standards to allow the Generator Owner to perform only selected TO functions. For additional information, please see Manitoba Hydro's comments submitted in the comment period ending November 18, 2011. Manitoba Hydro does not believe that the SDT fully addressed our concerns in their responses to our comments in that commenting period.</p>
<p><b>Response:</b> Thank you for your comment. The SDT must act within the scope of the SAR for this project. The comments appear to indicate that the entity disagrees with the SAR although they cite the Technical Justification document. The Technical Justification document is meant to be used to show how the SDT arrived at its decisions to revise only 4 reliability standards as opposed to all that were originally included in the Ad Hoc report, or those in the cited FERC orders.</p>		
<p>MRO NSRF</p>		<p><i>Section D, Article 1.3 Data Retention</i> states that the entities retain evidence for the entire audit period since the last audit. Furthermore, in the 2<sup>nd</sup> paragraph of Article 1.3, it states that an entity “shall retain evidence of the implementation of its Protection System maintenance and testing program for three years.”</p> <p>If an entity is to prove compliance related to R2.1 and R2.2 of PRC-005-1.1a, the NSRF recommends that Evidence Retention be revised to state “the two most recent performance of each distinct maintenance activity for the Protection System Components, or all performances of each distinct maintenance activity for the Protection System Component since the previous scheduled audit date, whichever is longer.” This agrees with the current draft in progress for PRC-005-2 Section D, Compliance, Article 1.3, paragraph 4.</p> <p>The NSRF is also concerned with those testing intervals, such as 12 years, which would dictate a Registered Entity maintain 24 years of records, which is unreasonable. This should be revised to have documentation for <u>the most current</u> one testing interval, if after 06/18/07.</p> <p>The NSRF believes that “the term “generation” in R1 and R2 should be changed to “generator”. If changed, both Measures will need to be updated as well.</p>

Organization	Yes or No	Question 2 Comment
<p><b>Response:</b> Thank you for your comment. The Data Retention section was revised by NERC staff to add boilerplate compliance language approved elsewhere. Thus, it is outside the scope of the SDT and no change was made.</p> <p>In R1 and R2, the reference to “generation” was in the original standard, referring to a generation Protection System. While “generator” may work better here, it is not within the scope of the 2010-07 SDT to change language outside the surgical insertion of “generator interconnection Facility.”</p>		
Oncor Electric Delivery Company	No	
Imperial Irrigation District (IID)	No	
Northeast Power Coordinating Council	No	
Imperial Irrigation District (IID)	No	
Dominion- NERC Compliance Policy	No	
Xcel Energy	No	
Dynergy Inc.	No	
Public Service Enterprise Group	No	
Ingleside Cogeneration LP	No	

Organization	Yes or No	Question 2 Comment
We Energies	No	

END OF REPORT

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary. When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.*

### **Right-of-Way (ROW)**

A corridor of land on which electric lines may be located. The applicable Transmission Owner or applicable Generator Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

The current glossary definition of this NERC term was modified to include applicable Generator Owners.



FAC-003-2 was developed under Project 2007-07. The standard was balloted and adopted by the NERC Board of Trustees, but the Project 2010-07 drafting team does not want to assume that FAC-003-2 will be approved by FERC and other governmental authorities. Thus, the Project 2010-07 drafting team has developed two sets of proposed changes: one to this version, FAC-003-1, the current FERC-approved version of the standard, and one to FAC-003-2, the version developed by the Project 2007-07 team and adopted by NERC's Board of Trustees.

## A. Introduction

1. **Title:** Transmission Vegetation Management Program

2. **Number:** FAC-003-X

3. **Purpose:** To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation-related outages of the transmission systems to the respective Regional Entity (RE) and the North American Electric Reliability Council (NERC).

Within the text of NERC Reliability Standard FAC-003-X, “transmission line(s)” and “applicable line(s)” can also refer to the generation Facilities as referenced in 4.4 and its subsections.

### 4. Applicability:

#### 4.1. Applicable Transmission Owner

4.1.1. Transmission Owner that owns overhead transmission lines operated at 200 kV and above and to any lower voltage lines designated by the RE as critical to the reliability of the electric system in the region.

#### 4.2. Applicable Generator Owner

4.2.1. Generator Owner that owns an overhead transmission line(s) that (1) extends greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) does not have a clear line of sight<sup>1</sup> from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and is operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.

### 5. Effective Dates:

There are three effective dates associated with this implementation plan:

The first effective date applies to Transmission Owners.

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no

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<sup>1</sup> “Clear line of sight” means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.

regulatory approval is required, all requirements applied to the Transmission Owner become effective upon Board of Trustees' adoption.

The second effective date allows Generator Owners time to prepare a formal transmission vegetation management program as outlined in Requirement R1.

In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The third effective date allows entities time to comply with Requirements R2, R3, and R4.

In those jurisdictions where regulatory approval is required, Requirements R2, R3, and R4 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R2, R3, and R4 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

## **B. Requirements**

**R1.** Each applicable Transmission Owner or applicable Generator Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the applicable Transmission Owner's or applicable Generator Owner's objectives, practices, approved procedures, and work specifications<sup>2</sup>.

**R1.1.** The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the applicable Transmission Owner's or applicable Generator Owner's transmission lines.

**R1.2.** Each applicable Transmission Owner or applicable Generator Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the applicable Transmission Owner or applicable Generator Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.

**R1.2.1.** Clearance 1 — The applicable Transmission Owner or applicable Generator Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the applicable Transmission Owner or applicable Generator Owner plans to return for future vegetation management work. Local conditions may include, but are not

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<sup>2</sup> ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.

limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.

**R1.2.2.** Clearance 2 — The applicable Transmission Owner or applicable Generator Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These applicable Transmission Owner-specific or applicable Generator Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.

**R1.2.2.1** Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.

**R1.2.2.2** Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.

**R1.3.** All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner or Generator Owner, to perform their duties.

**R1.4.** Each applicable Transmission Owner or applicable Generator Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner or applicable Generator Owner is restricted from attaining the clearances specified in Requirement 1.2.1.

**R1.5.** Each Transmission Owner or applicable Generator Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.

[VRF – High]

**R2.** Each applicable Transmission Owner or applicable Generator Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each applicable Transmission Owner or applicable Generator Owner shall have systems and procedures for documenting and tracking the planned vegetation

management work and ensuring that the vegetation management work was completed according to work specifications.

*[VRF – High]*

- R3.** Each applicable Transmission Owner or applicable Generator Owner shall report quarterly to its Regional Entity, or the Regional Entity’s designee, sustained transmission line outages determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation.
- R3.1.** Multiple sustained 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.
- R3.2.** The applicable Transmission Owner or applicable Generator Owner is not required to report to the Regional Entity, or the Regional Entity’s designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).
- R3.3.** The outage information provided by the applicable Transmission Owner or applicable Generator Owner to the Regional Entity, or the Regional Entity’s designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.
- R3.4.** An outage shall be categorized as one of the following:
- R3.4.1.** Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;
  - R3.4.2.** Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;
  - R3.4.3.** Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.

*[VRF – Lower]*

- R4.** The Regional Entity shall report the outage information provided to it by applicable Transmission Owners or applicable Generator Owners, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported outages.

*[VRF – Lower]*

**C. Measures**

- M1.** Each applicable Transmission Owner or applicable Generator Owner has a documented TVMP, as identified in Requirement 1.

- M1.1.** Each applicable Transmission Owner or applicable Generator Owner has documentation that the applicable Transmission Owner or applicable Generator Owner performed the vegetation inspections as identified in Requirement 1.1.
- M1.2.** Each applicable Transmission Owner or applicable Generator Owner has documentation that describes the clearances identified in Requirement 1.2.
- M1.3.** Each applicable Transmission Owner or applicable Generator Owner has documentation that the personnel directly involved in the design and implementation of the applicable Transmission Owner's or applicable Generator Owner TVMP hold the qualifications identified by the Transmission Owner or applicable Generator Owner as required in Requirement 1.3.
- M1.4.** Each applicable Transmission Owner or applicable Generator Owner has documentation that it has identified any areas not meeting the applicable Transmission Owner's or applicable Generator Owner's standard for vegetation management and any mitigating measures the Transmission Owner or applicable Generator Owner has taken to address these deficiencies as identified in Requirement 1.4.
- M1.5.** Each applicable Transmission Owner or applicable Generator Owner has a documented process for the immediate communication of imminent threats by vegetation as identified in Requirement 1.5.
- M2.** Each applicable Transmission Owner or applicable Generator Owner has documentation that the Transmission Owner implemented the work plan identified in Requirement 2.
- M3.** Each applicable Transmission Owner or applicable Generator Owner has documentation that it has supplied quarterly outage reports to the Regional Entity, or the Regional Entity's designee, as identified in Requirement 3.
- M4.** The Regional Entity has documentation that it provided quarterly outage reports to NERC as identified in Requirement 4.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

Compliance Monitor:

- Regional Entity for the Transmission Owner and Generator Owner
- Electric Reliability Organization or another Regional Entity approved by the ERO and FERC or other applicable government authorities

**1.2. Compliance Monitoring and Enforcement Processes:**

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

**1.3. Data Retention**

The applicable Transmission Owner and applicable Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance

Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The applicable Transmission Owner and applicable Generator Owner shall retain evidence of Requirement 1, Measure 1, Requirement 2, Measure 2, and Requirement 3, Measure 3 from its last audit.

**1.4. Additional Compliance Information**

None.

**2. Violation Severity Levels**

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity did not include and keep current one of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current two of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current three of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current all required elements of the TVMP, as directed by the requirement.
R1.1	N/A	N/A	The applicable entity TVMP did not define a schedule, as directed by the requirement, or the type of ROW vegetation inspections, as directed by the requirement.	The applicable entity TVMP did not define a schedule, as directed by the requirement, nor the type of ROW vegetation inspections, as directed by the requirement.
R1.2	N/A	N/A	N/A	The responsible entity, in its TVMP, failed to identify and document clearances between vegetation and any overhead, ungrounded supply conductors.  OR  The responsible entity, in its TVMP, failed to take into

				<p>consideration transmission line voltage, or the effects of ambient temperature on conductor sag under maximum design loading, or the effects of wind velocities on conductor sway.</p> <p>OR</p> <p>The responsible entity, in its TVMP, failed to establish Clearance 1 or Clearance 2 values.</p>
R1.2.1	N/A	N/A	N/A	<p>The responsible entity failed to determine and document an appropriate clearance distance to be achieved at the time of transmission vegetation management work taking into account local conditions and the expected time frame in which the responsible entity expects to return for future vegetation management work.</p> <p>OR</p> <p>The responsible entity documented a Clearance 1 value that was smaller than its Clearance 2 value.</p>

R1.2.2	N/A	N/A	N/A	The responsible entity failed to determine and document Clearance 2 values taking into account local conditions and the expected time frame in which the responsible entity expects to return for future vegetation management work.
R1.2.2.1	N/A	N/A	N/A	Where transmission system transient overvoltage factors were known, clearances were not derived from Table 5, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.
R1.2.2.2	N/A	N/A	N/A	Where transmission system transient overvoltage factors are known, clearances were not derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.
R1.3	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, one of those persons did not hold appropriate qualifications and	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, two of those persons did not hold appropriate qualifications and	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, three of those persons did not hold appropriate qualifications and	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, more than three of those persons did not hold appropriate qualifications and



	training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, 5% or less of those persons did not hold appropriate qualifications and training to perform their duties.	training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 5% up to (and including) 10% of those persons did not hold appropriate qualifications and training to perform their duties.	training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 10% up to (and including) 15% of those persons did not hold appropriate qualifications and training to perform their duties.	training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 15% of those persons did not hold appropriate qualifications and training to perform their duties.
R1.4	N/A	N/A	N/A	The responsible entity's TVMP does not include mitigation measures to achieve sufficient clearances where restrictions to the ROW are in effect.
R1.5	N/A	N/A	N/A	The responsible entity did not establish or did not document a process for the immediate communication of vegetation conditions that present an imminent threat of line outage, as directed by the requirement.
R2	The responsible entity did not meet one of the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the	The responsible entity did not meet two of the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the	The responsible entity did not meet the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the	The responsible entity does not have an annual plan for vegetation management.  OR  The responsible entity has not implemented the annual plan for vegetation

	annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	management.
R3	<p>The responsible entity failed to provide a quarterly outage report, but did not experience any reportable outages.</p> <p>OR</p> <p>The responsible entity provided a quarterly report, but failed to report in the manner specified by one or more of the following subcomponents of Requirement R3: R3.1 or R3.2.</p>	<p>The responsible entity provided a quarterly report, but failed to include information required by R3.3.</p>	<p>The responsible entity provided a quarterly outage report, but failed to include a reportable Category 3 outage as described in R3.4.3.</p>	<p>The responsible entity experienced reportable outages but failed to provide a quarterly report.</p> <p>OR</p> <p>The responsible entity provided a quarterly outage report, but failed to include a reportable Category 1 (as described in R3.4.1) or Category 2 outage (as described in R3.4.2).</p>
R4	N/A	N/A	N/A	N/A

**E. Regional Differences**

None Identified.

**Version History**

Version	Date	Action	Change Tracking
1	TBA	<ol style="list-style-type: none"> <li>1. Added “Standard Development Roadmap.”</li> <li>2. Changed “60” to “Sixty” in section A, 5.2.</li> <li>3. Added “Proposed Effective Date: April 7, 2006” to footer.</li> <li>4. Added “Draft 3: November 17, 2005” to footer.</li> </ol>	01/20/06

**Standard FAC-003-X — Transmission Vegetation Management Program**

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X	May 16, 2011	Made standard applicable to certain qualifying Generator Owners and brought overall standard format up to date	Revision under Project 2010-07

## Definitions of Terms Used in Standard

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### **Right-of-Way (ROW)**

A corridor of land on which electric lines may be located. The applicable Transmission Owner or applicable Generator Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

The current glossary definition of this NERC term was modified to include applicable Generator Owners.

~~FAC-003-2 was developed under Project 2007-07. The standard was balloted and adopted by the NERC Board of Trustees, but the Project 2010-07 drafting team does not want to assume that FAC-003-2 will be approved by FERC and other governmental authorities. Thus, the Project 2010-07 drafting team has developed two sets of proposed changes: one to this version, FAC-003-1, the current FERC-approved version of the standard, and one to FAC-003-2, the version developed by the Project 2007-07 team and adopted by NERC's Board of Trustees.~~

~~FAC-003-2 is currently under development under Project 2007-07. The project is nearing its final stages, but the Project 2010-07 drafting team does not want to assume that the project will be approved by NERC's Board of Trustees (BOT) or FERC. Thus, the Project 2010-07 drafting team has developed two sets of proposed changes: one to this version, FAC-003-1, the current FERC approved version of the standard, and one to FAC-003-2, the latest draft of Version 2 as proposed by the Project 2007-07 team~~

~~If FAC-003-2 is approved by NERC's BOT, the Project 2010-07 drafting team will likely proceed with the modifications it has proposed in the redline to that version of the standard. These changes would be submitted for stakeholder approval and balloted as FAC-003-3. FAC-003-2 would be retired once FAC-003-3 was approved.~~

~~If, however, FAC-003-2 remains under development, the Project 2010-07 drafting team will proceed with the changes to FAC-003-1 seen below to avoid further delay of its project goals. Changes to FAC-003-1 would address the addition of Generator Owners to the applicability section, modifications to the NERC defined terms Right of Way to include Generator Owners, and some formatting changes to bring the standard up to date. These changes would not be comprehensive; rather, they would aim to include the generator interconnection Facility in the standard with as few other changes as possible.~~

## A. Introduction

1. **Title:** Transmission Vegetation Management Program

2. **Number:** FAC-003-X

3. **Purpose:** To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation-related outages of the transmission systems to the respective Regional Entity (RE) and the North American Electric Reliability Council (NERC).

Within the text of NERC Reliability Standard FAC-003-X, "transmission line(s)" and "applicable line(s)" can also refer to the generation Facilities as referenced in 4.4 and its subsections.

### 4. Applicability:

4.1. ~~Regional Entity.~~

4.2. Applicable Transmission Owner

4.2.1. Transmission Owner that owns overhead transmission lines operated at 200 kV and above and to any lower voltage lines designated by the RE as critical to the reliability of the electric system in the region.

4.3. Applicable Generator Owner

4.3.1. Generator Owner that owns an overhead transmission line(s) that (1) extends greater than one mile or 1.609 kilometers beyond the fenced area of the

generating station switchyard ~~up~~ to the point of interconnection with a Transmission Owner's Facility or (2) does not have a clear line of sight<sup>1</sup> from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and is operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.

## 5. Effective Dates:

There are three effective dates associated with this implementation plan:

The first effective date applies to Transmission Owners.

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner become effective upon Board of Trustees' adoption.

The second effective date allows Generator Owners time to prepare a formal transmission vegetation management program as outlined in Requirement R1.

In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The third effective date allows entities time to comply with Requirements R2, R3, and R4.

In those jurisdictions where regulatory approval is required, Requirements R2, R3, and R4 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R2, R3, and R4 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

## B. Requirements

**R1.** Each applicable Transmission Owner or applicable Generator Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the applicable Transmission Owner's or applicable Generator Owner's objectives, practices, approved procedures, and work specifications<sup>2</sup>.

**R1.1.** The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the applicable Transmission Owner's or applicable Generator Owner's transmission lines.

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<sup>1</sup> "Clear line of sight" means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.

<sup>2</sup> ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.

- R1.2.** Each applicable Transmission Owner or applicable Generator Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the applicable Transmission Owner or applicable Generator Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.
- R1.2.1.** Clearance 1 — The applicable Transmission Owner or applicable Generator Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the applicable Transmission Owner or applicable Generator Owner plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.
- R1.2.2.** Clearance 2 — The applicable Transmission Owner or applicable Generator Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These applicable Transmission Owner-specific or applicable Generator Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.
- R1.2.2.1** Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.
- R1.2.2.2** Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.
- R1.3.** All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner or Generator Owner, to perform their duties.
- R1.4.** Each applicable Transmission Owner or applicable Generator Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner or applicable Generator Owner is restricted from attaining the clearances specified in Requirement 1.2.1.

**R1.5.** Each Transmission Owner or applicable Generator Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.

*[VRF – High]*

**R2.** Each applicable Transmission Owner or applicable Generator Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each applicable Transmission Owner or applicable Generator Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.

*[VRF – High]*

**R3.** Each applicable Transmission Owner or applicable Generator Owner shall report quarterly to its Regional Entity, or the Regional Entity’s designee, sustained transmission line outages determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation.

**R3.1.** Multiple sustained 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.

**R3.2.** The applicable Transmission Owner or applicable Generator Owner is not required to report to the Regional Entity, or the Regional Entity’s designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).

**R3.3.** The outage information provided by the applicable Transmission Owner or applicable Generator Owner to the Regional Entity, or the Regional Entity’s designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

**R3.4.** An outage shall be categorized as one of the following:

**R3.4.1.** Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;



**R3.4.2.** Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;

**R3.4.3.** Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.

*[VRF – Lower]*

**R4.** The Regional Entity shall report the outage information provided to it by applicable Transmission Owners or applicable Generator Owners, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported outages.

*[VRF – Lower]*

**C. Measures**

**M1.** Each applicable Transmission Owner or applicable Generator Owner has a documented TVMP, as identified in Requirement 1.

**M1.1.** Each applicable Transmission Owner or applicable Generator Owner has documentation that the applicable Transmission Owner or applicable Generator Owner performed the vegetation inspections as identified in Requirement 1.1.

**M1.2.** Each applicable Transmission Owner or applicable Generator Owner has documentation that describes the clearances identified in Requirement 1.2.

**M1.3.** Each applicable Transmission Owner or applicable Generator Owner has documentation that the personnel directly involved in the design and implementation of the applicable Transmission Owner's or applicable Generator Owner TVMP hold the qualifications identified by the Transmission Owner or applicable Generator Owner as required in Requirement 1.3.

**M1.4.** Each applicable Transmission Owner or applicable Generator Owner has documentation that it has identified any areas not meeting the applicable Transmission Owner's or applicable Generator Owner's standard for vegetation management and any mitigating measures the Transmission Owner or applicable Generator Owner has taken to address these deficiencies as identified in Requirement 1.4.

**M1.5.** Each applicable Transmission Owner or applicable Generator Owner has a documented process for the immediate communication of imminent threats by vegetation as identified in Requirement 1.5.

**M2.** Each applicable Transmission Owner or applicable Generator Owner has documentation that the Transmission Owner implemented the work plan identified in Requirement 2.

**M3.** Each applicable Transmission Owner or applicable Generator Owner has documentation that it has supplied quarterly outage reports to the Regional Entity, or the Regional Entity's designee, as identified in Requirement 3.

**M4.** The Regional Entity has documentation that it provided quarterly outage reports to NERC as identified in Requirement 4.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

Compliance Monitor:

- Regional Entity for the Transmission Owner and Generator Owner

- Electric Reliability Organization or another Regional Entity approved by the ERO and FERC or other applicable government authorities

**1.2. Compliance Monitoring and Enforcement Processes:**

Compliance Audits  
Self-Certifications  
Spot Checking  
Compliance Violation Investigations  
Self-Reporting  
Complaints

**1.3. Data Retention**

The applicable Transmission Owner and applicable Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The applicable Transmission Owner and applicable Generator Owner shall retain evidence of Requirement 1, Measure 1, Requirement 2, Measure 2, and Requirement 3, Measure 3 from its last audit.

**1.4. Additional Compliance Information**

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity did not include and keep current one of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current two of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current three of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current all required elements of the TVMP, as directed by the requirement.
R1.1	N/A	N/A	The applicable entity TVMP did not define a schedule, as directed by the requirement, or the type of ROW vegetation inspections, as directed by the requirement.	The applicable entity TVMP did not define a schedule, as directed by the requirement, nor the type of ROW vegetation inspections, as directed by the requirement.
R1.2	N/A	N/A	N/A	<p>The responsible entity, in its TVMP, failed to identify and document clearances between vegetation and any overhead, ungrounded supply conductors.</p> <p>OR</p> <p>The responsible entity, in its TVMP, failed to take into consideration transmission line voltage, or the effects of ambient temperature on conductor sag under maximum design loading, or the effects of wind velocities on conductor sway.</p>

				<p>OR</p> <p>The responsible entity, in its TVMP, failed to establish Clearance 1 or Clearance 2 values.</p>
R1.2.1	N/A	N/A	N/A	<p>The responsible entity failed to determine and document an appropriate clearance distance to be achieved at the time of transmission vegetation management work taking into account local conditions and the expected time frame in which the responsible entity expects to return for future vegetation management work.</p> <p>OR</p> <p>The responsible entity documented a Clearance 1 value that was smaller than its Clearance 2 value.</p>
R1.2.2	N/A	N/A	N/A	<p>The responsible entity failed to determine and document Clearance 2 values taking into account local conditions and the expected time frame in which the responsible entity expects to return for future vegetation management work.</p>
R1.2.2.1	N/A	N/A	N/A	<p>Where transmission system transient overvoltage factors were known, clearances were not derived from Table 5,</p>

				IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.
R1.2.2.2	N/A	N/A	N/A	Where transmission system transient overvoltage factors are known, clearances were not derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.
R1.3	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, one of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, 5% or less of those persons did not hold appropriate qualifications and training to perform their duties.	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, two of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 5% up to (and including) 10% of those persons did not hold appropriate qualifications and training to perform their duties.	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, three of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 10% up to (and including) 15% of those persons did not hold appropriate qualifications and training to perform their duties.	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, more than three of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 15% of those persons did not hold appropriate qualifications and training to perform their duties.
R1.4	N/A	N/A	N/A	The responsible entity's TVMP does not include mitigation measures to achieve sufficient clearances where restrictions to the ROW are in effect.

R1.5	N/A	N/A	N/A	The responsible entity did not establish or did not document a process for the immediate communication of vegetation conditions that present an imminent threat of line outage, as directed by the requirement.
R2	The responsible entity did not meet one of the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	The responsible entity did not meet two of the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	The responsible entity did not meet the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	The responsible entity does not have an annual plan for vegetation management.  OR  The responsible entity has not implemented the annual plan for vegetation management.
R3	The responsible entity failed to provide a quarterly outage report, but did not experience any reportable outages.  OR  The responsible entity provided a quarterly report, but failed to report in the manner specified by one or more of the following subcomponents of Requirement R3: R3.1 or R3.2.	The responsible entity provided a quarterly report, but failed to include information required by R3.3.	The responsible entity provided a quarterly outage report, but failed to include a reportable Category 3 outage as described in R3.4.3.	The responsible entity experienced reportable outages but failed to provide a quarterly report.  OR  The responsible entity provided a quarterly outage report, but failed to include a reportable Category 1 (as described in R3.4.1) or Category 2 outage (as described in R3.4.2).
R4	N/A	N/A	N/A	N/A

E. **Regional Differences**

None Identified.

**Version History**

Version	Date	Action	Change Tracking
1	TBA	<ol style="list-style-type: none"> <li>1. Added “Standard Development Roadmap.”</li> <li>2. Changed “60” to “Sixty” in section A, 5.2.</li> <li>3. Added “Proposed Effective Date: April 7, 2006” to footer.</li> <li>4. Added “Draft 3: November 17, 2005” to footer.</li> </ol>	01/20/06
X	May 16, 2011	Made standard applicable to certain qualifying Generator Owners and brought overall standard format up to date	Revision under Project 2010-07

## Effective Dates

There are two effective dates associated with this standard.

The first effective date allows Generator Owners time to develop documented maintenance strategies or procedures or processes or specifications as outlined in Requirement R3.

In those jurisdictions where regulatory approval is required, Requirement R3 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The second effective date allows entities time to comply with Requirements R1, R2, R4, R5, R6, and R7.

In those jurisdictions where regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.
2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.
3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.



4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.
  
5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

Version History

<b>Version</b>	<b>Date</b>	<b>Action</b>	<b>Change Tracking</b>
3	September 29, 2011	Using the latest draft of FAC-003-2 from the Project 2007-07 SDT, modified proposed definitions and Applicability to include Generator Owners of a certain length.	Revision under Project 2010-07

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

### **Right-of-Way (ROW)**

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria.

The current glossary definition of this NERC term is modified to address the issues set forth in Paragraph 734 of FERC Order 693.

### **Vegetation Inspection**

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the applicable Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.

Current definition of Vegetation Inspection:  
The systematic examination of a transmission corridor to document vegetation conditions.

### **Minimum Vegetation Clearance Distance (MVCD)**

The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

*When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.*

FAC-003-2 was developed under Project 2007-07. The standard was balloted and adopted by the NERC Board of Trustees, but the Project 2010-07 drafting team does not want to assume that FAC-003-2 will be approved by FERC and other governmental authorities. Thus, the Project 2010-07 drafting team has developed two sets of proposed changes: one to this version, FAC-003-2, the version developed by the Project 2007-07 team and adopted by NERC’s Board of Trustees, and one to FAC-003-1, the current FERC-approved version of the standard.

## A. Introduction

- 1. Title:** Transmission Vegetation Management
- 2. Number:** FAC-003-3
- 3. Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

### 4. Applicability

#### 4.1. Functional Entities:

##### 4.1.1. Applicable Transmission Owners

4.1.1.1 Transmission Owners that own Transmission Facilities defined in 4.2.

##### 4.1.2 Applicable Generator Owners

4.1.2.1 Generator Owners that own generation Facilities defined in 4.3

- 4.2. Transmission Facilities:** Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal<sup>1</sup>, state, provincial, public, private, or tribal entities:

4.2. 1 Each overhead transmission line operated at 200kV or higher.

**Rationale:** The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

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<sup>1</sup> EPAAct 2005 section 1211c: “Access approvals by Federal agencies.”

**4.2.2** Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.

**4.2.3** Each overhead transmission line operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

**4.2.4** Each overhead transmission line identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

**4.3. Generation Facilities:** Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal<sup>2</sup>, state, provincial, public, private, or tribal entities:

**4.3.1** Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner’s Facility or (2) do not have a clear line of sight<sup>3</sup> from the generating station switchyard fence to the point of interconnection with a Transmission Owner’s Facility and are:

Within the text of NERC Reliability Standard FAC-003-3, “transmission line(s) and “applicable line(s) can also refer to the generation Facilities as referenced in 4.3 and its subsections.

**4.3.1.1** Operated at 200kV or higher; or

**4.3.1.2** Operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator; or

**4.3.1.3** Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

**Enforcement:**

The Requirements within a Reliability Standard govern and will be enforced. The Requirements within a Reliability Standard define what an entity must do to be compliant and binds an entity to certain obligations of performance under Section 215 of the Federal Power Act. Compliance will in all cases be measured by determining whether a party met or failed to meet the Reliability Standard Requirement given the specific facts and circumstances of its use, ownership or operation of the bulk power system.

Measures provide guidance on assessing non-compliance with the Requirements. Measures are the evidence that could be presented to demonstrate compliance with a Reliability Standard Requirement and are not intended to contain the quantitative metrics for determining satisfactory performance nor to limit how an entity may demonstrate compliance if valid alternatives to

<sup>2</sup> EPAAct 2005 section 1211c: “Access approvals by Federal agencies.”

<sup>3</sup> “Clear line of sight” means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.

demonstrating compliance are available in a specific case. A Reliability Standard may be enforced in the absence of specified Measures.

Entities must comply with the “Compliance” section in its entirety, including the Administrative Procedure that sets forth, among other things, reporting requirements.

The “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” are provided for informational purposes. They are designed to convey guidance from NERC’s various activities. The “Guideline and Technical Basis” section and text boxes with “Examples” and “Rationale” are not intended to establish new Requirements under NERC’s Reliability Standards or to modify the Requirements in any existing NERC Reliability Standard. Implementation of the “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” is not a substitute for compliance with Requirements in NERC’s Reliability Standards.”

## **5. Background:**

This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

- a) Performance-based — defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome?*
- b) Risk-based — preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?*
- c) Competency-based — defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?*

The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constraints such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

For this standard, the requirements have been developed as follows:

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term “public lands” includes municipal lands, village lands, city lands, and a host of other governmental entities.

This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

## B. Requirements and Measures

**R1.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below<sup>4</sup> [*Violation Risk Factor: High*] [*Time Horizon: Real-time*]:

1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage<sup>5</sup>,
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage<sup>6</sup>,
3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage<sup>4</sup>,
4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage<sup>4</sup>.

**M1.** Each applicable Transmission Owner

### Rationale for R1 and R2:

Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable Transmission Owner's or applicable Generator Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.
2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

<sup>4</sup> This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.

<sup>5</sup> If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

<sup>6</sup> Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.



and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

- R2.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below<sup>2</sup> [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time*]:
1. An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage<sup>3</sup>,
  2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage<sup>4</sup>,
  3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage<sup>4</sup>,
  4. An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage<sup>4</sup>
- M2.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)

**R3.** Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following:

**3.1** Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;

**3.2** Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning];

**Rationale**

The documentation provides a basis for evaluating the competency of the applicable Transmission Owner’s or applicable Generator Owner’s vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions. See Figure

**M3.** The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

**R4.** Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment [Violation Risk Factor: Medium] [Time Horizon: Real-time].

**Rationale**

This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

**M4.** Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

**R5.** When a applicable Transmission Owner and applicable Generator Owner is constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

**Rationale**

Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

**M5.** Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

**Rationale**

Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could

**R6.** Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW<sup>7</sup> [*Violation Risk Factor:*

<sup>7</sup> When the applicable Transmission Owner or applicable Generator Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.

*Medium*] [*Time Horizon: Operations Planning*].

**M6.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

**R7.** Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan

**Rationale**

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

(measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

- Change in expected growth rate/ environmental factors
- Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner<sup>8</sup>
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Emerging technologies

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<sup>8</sup> Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.

- M7.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records.  
(R7)

## **C. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1 Compliance Enforcement Authority**

#### **1.2 Regional Entity Evidence Retention**

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, Measures M1, M2, M3, M5, M6 and M7 for three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### **1.3 Compliance Monitoring and Enforcement Processes:**

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaint

Periodic Data Submittal

#### **1.4 Additional Compliance Information**

***Periodic Data Submittal:*** The applicable Transmission Owner and applicable Generator Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

**Table of Compliance Elements**

R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Real-time	High			<p>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.</p>	<p>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following:</p> <ul style="list-style-type: none"> <li>• A fall-in from inside the active transmission line ROW</li> <li>• Blowing together of applicable lines and vegetation located inside the active transmission line ROW</li> <li>• A grow-in</li> </ul>
R2	Real-time	Medium			<p>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.</p>	<p>The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following:</p> <ul style="list-style-type: none"> <li>• A fall-in from inside the active transmission line</li> </ul>



						<p>ROW</p> <ul style="list-style-type: none"> <li>• Blowing together of applicable lines and vegetation located inside the active transmission line ROW</li> <li>• A grow-in</li> </ul>
R3	Long-Term Planning	Lower		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity's applicable lines. (Requirement R3, Part 3.2)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines. Requirement R3, Part 3.1)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity's applicable lines.
R4	Real-time	Medium			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5	Operations Planning	Medium				The responsible entity did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6	Operations	Medium	The responsible entity	The responsible entity failed	The responsible entity failed to	The responsible entity failed to

	Planning		failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7	Operations Planning	Medium	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Differences

None.

E. Interpretations

None.

F. Associated Documents

Guideline and Technical Basis (attached).

## Guideline and Technical Basis

### Effective dates:

The first two sentences of the Effective Dates section is standard language used in most NERC standards to cover the general effective date and is sufficient to cover the vast majority of situations. Five special cases are needed to cover effective dates for individual lines which undergo transitions after the general effective date. These special cases cover the effective dates for those lines which are initially becoming subject to the standard, those lines which are changing their applicability within the standard, and those lines which are changing in a manner that removes their applicability to the standard.

Case 1 is needed because the Planning Coordinators may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2011 may identify a line to have that designation beginning in PY 2021, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. The table below has some explanatory examples of the application.

<u>Date that Planning Study is completed</u>	<u>PY the line will become an IROL element</u>	<u>Date 1</u>	<u>Date 2</u>	<u>Effective Date The latter of Date 1 or Date 2</u>
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Case 2 is needed because a line operating below 200kV designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Case 3 is needed because a line operating at 200 kV or above that once was designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network. Such changes result in the need to apply R1 to that line until that date is reached and then to apply R2 to that line thereafter.

Case 4 is needed because an existing line that is to be operated at 200 kV or above can be acquired by an applicable Transmission Owner or applicable Generator Owner from a third party

such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network which will thereafter make the line subject to the standard.

Case 5 is needed because an existing line that is operated below 200 kV can be acquired by an applicable Transmission Owner or applicable Generator Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network. In this special case the line upon acquisition was designated as an element of an Interconnection Reliability Operating Limit (IROL) or an element of a Major WECC Transfer Path.

### **Defined Terms:**

#### **Explanation for revising the definition of ROW:**

The current NERC glossary definition of Right of Way has been modified to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This modified definition represents a slight but significant departure from the strict legal definition of “right of way” in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the revised definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

#### **Explanation for revising the definition of Vegetation Inspections:**

The current glossary definition of this NERC term is being modified to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

#### **Explanation of the definition of the MVCD:**

The MVCD is a calculated minimum distance that is derived from the Gallet Equations. This is a method of calculating a flash over distance that has been used in the design of high voltage

transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 below provides MVCD values for various voltages and altitudes. Details of the equations and an example calculation are provided in Appendix 1 of the Technical Reference Document.

**Requirements R1 and R2:**

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each applicable Transmission Owner or applicable Generator Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element of an IROL or Major WECC Transfer Path. R2 is applicable to all other lines that are not elements of IROLs, and not elements of Major WECC Transfer Paths.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations as described more fully in the Technical Reference document.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will prevent transmission outages.

If the applicable Transmission Owner or applicable Generator Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

### **Requirement R3:**

R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable Transmission Owner or applicable Generator Owner uses for vegetation management.

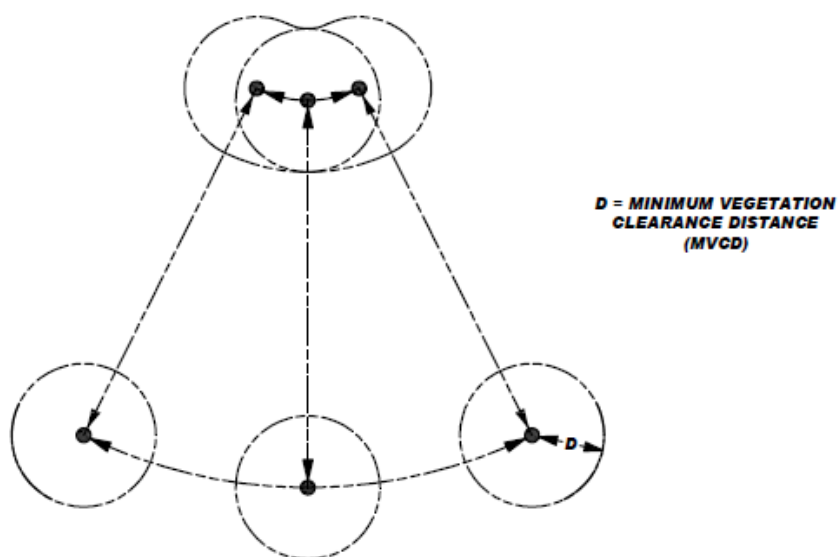
An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an applicable Transmission Owner or applicable Generator Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*

3. a stated *Vegetation Inspection frequency*
4. an *annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below. In the Technical Reference document more figures and explanations of conductor dynamics are provided.



**Figure 1**

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

#### **Requirement R4:**

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner or applicable Generator Owner employee who

personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

**Requirement R5:**

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:



- Identifying locations where the applicable Transmission Owner or applicable Generator Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The applicable Transmission Owner or applicable Generator Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

**Requirement R6:**

R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner's ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission Owner or applicable Generator Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be  $100/2000 = 0.05$  or 5%. The "Low VSL" for R6 would apply in this example.

**Requirement R7:**

R7 is a risk-based requirement. The applicable Transmission Owner or applicable Generator Owner is required to complete its an annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to

necessarily require a “span-by-span”, or even a “line-by-line” detailed description of all work to be performed. It is only intended to require that the applicable Transmission Owner or applicable Generator Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

For example, when an applicable Transmission Owner or applicable Generator Owner identifies 1,000 miles of applicable transmission lines to be completed in the applicable Transmission Owner’s or applicable Generator Owner’s annual plan, the applicable Transmission Owner or applicable Generator Owner will be responsible completing those identified miles. If a applicable Transmission Owner or applicable Generator Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be:  $1000 - 100$  (deferred miles) = 900 modified annual plan, or  $900 / 900 = 100\%$  completed annual miles. If an applicable Transmission Owner or applicable Generator Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be:  $1000 - 875 = 125$  miles failed to complete then,  $125$  miles (not completed) /  $1000$  total annual plan miles =  $12.5\%$  failed to complete.

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner’s or applicable Generator Owner’s system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.

In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner’s or applicable Generator Owner’s easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

**FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)<sup>9</sup>  
For Alternating Current Voltages (feet)**

( AC ) Nominal System Voltage (KV)	( AC ) Maximum System Voltage (kV) <sup>10</sup>	MVCD (feet)	MVCD (feet)	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet
		Over sea level up to 500 ft	Over 500 ft up to 1000 ft	Over 1000 ft up to 2000 ft	Over 2000 ft up to 3000 ft	Over 3000 ft up to 4000 ft	Over 4000 ft up to 5000 ft	Over 5000 ft up to 6000 ft	Over 6000 ft up to 7000 ft	Over 7000 ft up to 8000 ft	Over 8000 ft up to 9000 ft	Over 9000 ft up to 10000 ft	Over 10000 ft up to 11000 ft
765	800	8.2ft	8.33ft	8.61ft	8.89ft	9.17ft	9.45ft	9.73ft	10.01ft	10.29ft	10.57ft	10.85ft	11.13ft
500	550	5.15ft	5.25ft	5.45ft	5.66ft	5.86ft	6.07ft	6.28ft	6.49ft	6.7ft	6.92ft	7.13ft	7.35ft
345	362	3.19ft	3.26ft	3.39ft	3.53ft	3.67ft	3.82ft	3.97ft	4.12ft	4.27ft	4.43ft	4.58ft	4.74ft
287	302	3.88ft	3.96ft	4.12ft	4.29ft	4.45ft	4.62ft	4.79ft	4.97ft	5.14ft	5.32ft	5.50ft	5.68ft
230	242	3.03ft	3.09ft	3.22ft	3.36ft	3.49ft	3.63ft	3.78ft	3.92ft	4.07ft	4.22ft	4.37ft	4.53ft
161*	169	2.05ft	2.09ft	2.19ft	2.28ft	2.38ft	2.48ft	2.58ft	2.69ft	2.8ft	2.91ft	3.03ft	3.14ft
138*	145	1.74ft	1.78ft	1.86ft	1.94ft	2.03ft	2.12ft	2.21ft	2.3ft	2.4ft	2.49ft	2.59ft	2.7ft
115*	121	1.44ft	1.47ft	1.54ft	1.61ft	1.68ft	1.75ft	1.83ft	1.91ft	1.99ft	2.07ft	2.16ft	2.25ft
88*	100	1.18ft	1.21ft	1.26ft	1.32ft	1.38ft	1.44ft	1.5ft	1.57ft	1.64ft	1.71ft	1.78ft	1.86ft
69*	72	0.84ft	0.86ft	0.90ft	0.94ft	0.99ft	1.03ft	1.08ft	1.13ft	1.18ft	1.23ft	1.28ft	1.34ft

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

<sup>9</sup> The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

<sup>10</sup> Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

**TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)<sup>7</sup>  
For Alternating Current Voltages (meters)**

( AC ) Nominal System Voltage (KV)	( AC ) Maximum System Voltage (kV) <sup>8</sup>	MVCD meters  Over sea level up to 152.4 m	MVCD meters  Over 152.4 m up to 304.8 m	MVCD meters  Over 304.8 m up to 609.6m	MVCD meters  Over 609.6m up to 914.4m	MVCD meters  Over 914.4m up to 1219.2m	MVCD meters  Over 1219.2m up to 1524m	MVCD meters  Over 1524 m up to 1828.8 m	MVCD meters  Over 1828.8m up to 2133.6m	MVCD meters  Over 2133.6m up to 2438.4m	MVCD meters  Over 2438.4m up to 2743.2m	MVCD meters  Over 2743.2m up to 3048m	MVCD meters  Over 3048m up to 3352.8m
765	800	2.49m	2.54m	2.62m	2.71m	2.80m	2.88m	2.97m	3.05m	3.14m	3.22m	3.31m	3.39m
500	550	1.57m	1.6m	1.66m	1.73m	1.79m	1.85m	1.91m	1.98m	2.04m	2.11m	2.17m	2.24m
345	362	0.97m	0.99m	1.03m	1.08m	1.12m	1.16m	1.21m	1.26m	1.30m	1.35m	1.40m	1.44m
287	302	1.18m	0.88m	1.26m	1.31m	1.36m	1.41m	1.46m	1.51m	1.57m	1.62m	1.68m	1.73m
230	242	0.92m	0.94m	0.98m	1.02m	1.06m	1.11m	1.15m	1.19m	1.24m	1.29m	1.33m	1.38m
161*	169	0.62m	0.64m	0.67m	0.69m	0.73m	0.76m	0.79m	0.82m	0.85m	0.89m	0.92m	0.96m
138*	145	0.53m	0.54m	0.57m	0.59m	0.62m	0.65m	0.67m	0.70m	0.73m	0.76m	0.79m	0.82m
115*	121	0.44m	0.45m	0.47m	0.49m	0.51m	0.53m	0.56m	0.58m	0.61m	0.63m	0.66m	0.69m
88*	100	0.36m	0.37m	0.38m	0.40m	0.42m	0.44m	0.46m	0.48m	0.50m	0.52m	0.54m	0.57m
69*	72	0.26m	0.26m	0.27m	0.29m	0.30m	0.31m	0.33m	0.34m	0.36m	0.37m	0.39m	0.41m

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

**TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)<sup>7</sup>**  
 For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)
	Over sea level up to 500 ft	Over 500 ft up to 1000 ft	Over 1000 ft up to 2000 ft	Over 2000 ft up to 3000 ft	Over 3000 ft up to 4000 ft	Over 4000 ft up to 5000 ft	Over 5000 ft up to 6000 ft	Over 6000 ft up to 7000 ft	Over 7000 ft up to 8000 ft	Over 8000 ft up to 9000 ft	Over 9000 ft up to 10000 ft	Over 10000 ft up to 11000 ft
	(Over sea level up to 152.4 m)	(Over 152.4 m up to 304.8 m)	(Over 304.8 m up to 609.6m)	(Over 609.6m up to 914.4m)	(Over 914.4m up to 1219.2m)	(Over 1219.2m up to 1524m)	(Over 1524 m up to 1828.8 m)	(Over 1828.8m up to 2133.6m)	(Over 2133.6m up to 2438.4m)	(Over 2438.4m up to 2743.2m)	(Over 2743.2m up to 3048m)	(Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

**Notes:**

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet Equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 uses the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-01 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines, as such, are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-

service ac line is approximately 2.0 per unit. This value is a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below is considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit is considered a realistic maximum.

The Gallet Equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet Equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

While EPRI is currently trying to establish empirical data for spark-over distances to live vegetation, there are no spark-over formulas currently derived expressly for vegetation to conductor minimum distances. Therefore the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.



**Comparison of spark-over distances computed using Gallet wet equations vs.  
IEEE 516-2003 MAID distances**

( AC ) Nom System Voltage (kV)	( AC ) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 feet	Table 7 (Table D.5 for feet) IEEE 516-2003 MAID (ft) @ Alt. 3000 feet
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

## Effective Dates

There are two effective dates associated with this standard.

The first effective date allows Generator Owners time to develop documented maintenance strategies or procedures or processes or specifications as outlined in Requirement R3.

In those jurisdictions where regulatory approval is required, Requirement R3 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The second effective date allows entities time to comply with Requirements R1, R2, R4, R5, R6, and R7.

In those jurisdictions where regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.
2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.
3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.

4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.
5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

Version History

<b>Version</b>	<b>Date</b>	<b>Action</b>	<b>Change Tracking</b>
3	September 29, 2011	Using the latest draft of FAC-003-2 from the Project 2007-07 SDT, modified proposed definitions and Applicability to include Generator Owners of a certain length.	Revision under Project 2010-07

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

### **Right-of-Way (ROW)**

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria.

The current glossary definition of this NERC term is modified to address the issues set forth in Paragraph 734 of FERC Order 693.

### **Vegetation Inspection**

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the applicable Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.

Current definition of Vegetation Inspection:  
The systematic examination of a transmission corridor to document vegetation conditions.

### **Minimum Vegetation Clearance Distance (MVCD)**

The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

*When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.*

~~FAC-003-2 was developed under Project 2007-07. The standard was balloted and adopted by the NERC Board of Trustees, but the Project 2010-07 drafting team does not want to assume that FAC-003-2 will be approved by FERC and other governmental authorities. Thus, the Project 2010-07 drafting team has developed two sets of proposed changes: one to this version, FAC-003-2, the version developed by the Project 2007-07 team and adopted by NERC's Board of Trustees, and one to FAC-003-1, the current FERC-approved version of the standard.~~

~~FAC-003-2 is currently under development under Project 2007-07. The project is nearing its final stages, but the Project 2010-07 drafting team does not want to assume that the project will be approved by NERC's Board of Trustees (BOT) or FERC. Thus, the Project 2010-07 drafting team has developed two sets of proposed changes: one to this version, the latest draft of Version 2 as proposed by the Project 2007-07 team, and one to FAC-003-1, the current FERC-approved version of the standard.~~

~~If FAC-003-2 is approved by NERC's BOT, the Project 2010-07 drafting team will likely proceed with the modifications seen in this standard. These changes would be submitted for stakeholder approval and balloted as FAC-003-3. Several scenarios that could play out based on the order of the approval of these versions of the standards are addressed in the FAC-003-3 implementation plan.~~

~~If, however, FAC-003-2 remains under development, the Project 2010-07 drafting team will proceed with changes to FAC-003-1 to avoid further delay of its project goals. Changes to FAC-003-1 would address the addition of Generator Owners to the applicability, the proposal of modifications to the NERC defined term Right-of-Way to include applicable Generator Owners, and some formatting changes to bring the standard up to date. These changes would not be comprehensive; rather, they would aim to include the generator interconnection Facility in the standard with as few other changes as possible.~~

## A. Introduction

1. **Title:** Transmission Vegetation Management
2. **Number:** FAC-003-3
3. **Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.
4. **Applicability**
  - 4.1. **Functional Entities:**

**4.1.1. Applicable Transmission Owners**

**4.1.1.1.** Transmission Owners that own Transmission Facilities defined in 4.2.

**4.1.2. Applicable Generator Owners**

**4.1.2.1.** Generator Owners that own generation Facilities defined in 4.3

**4.2. Transmission Facilities:** Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal<sup>1</sup>, state, provincial, public, private, or tribal entities:

**4.2.1.** Each overhead transmission line operated at 200kV or higher.

**4.2.2.** Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.

**4.2.3.** Each overhead transmission line operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

**4.2.4.** Each overhead transmission line identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

**4.3. Generation Facilities:** Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal<sup>2</sup>, state, provincial, public, private, or tribal entities:

**4.3.1.** Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating -station switchyard to the point of interconnection with a Transmission Owner’s Facility or (2) do not have a clear line of sight<sup>3</sup> from the generating station switchyard

**Rationale:** The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

Within the text of NERC Reliability Standard FAC-003-3, “transmission line(s) and “applicable line(s) can also refer to the generation Facilities as referenced in 4.3 and its subsections.

<sup>1</sup> EPAAct 2005 section 1211c: “Access approvals by Federal agencies.”

<sup>2</sup> EPAAct 2005 section 1211c: “Access approvals by Federal agencies.”

fence to the point of interconnection with a Transmission Owner's and Facility and are:

- 4.3.1.1. Operated at 200kV or higher; or
- 4.3.1.2. Operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator; or-
- 4.3.1.3. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

Enforcement:

The Requirements within a Reliability Standard govern and will be enforced. The Requirements within a Reliability Standard define what an entity must do to be compliant and binds an entity to certain obligations of performance under Section 215 of the Federal Power Act. Compliance will in all cases be measured by determining whether a party met or failed to meet the Reliability Standard Requirement given the specific facts and circumstances of its use, ownership or operation of the bulk power system.

Measures provide guidance on assessing non-compliance with the Requirements. Measures are the evidence that could be presented to demonstrate compliance with a Reliability Standard Requirement and are not intended to contain the quantitative metrics for determining satisfactory performance nor to limit how an entity may demonstrate compliance if valid alternatives to demonstrating compliance are available in a specific case. A Reliability Standard may be enforced in the absence of specified Measures.

Entities must comply with the “Compliance” section in its entirety, including the Administrative Procedure that sets forth, among other things, reporting requirements.

The “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” are provided for informational purposes. They are designed to convey guidance from NERC’s various activities. The “Guideline and Technical Basis” section and text boxes with “Examples” and “Rationale” are not intended to establish new Requirements under NERC’s Reliability Standards or to modify the Requirements in any existing NERC Reliability Standard. Implementation of the “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” is not a substitute for compliance with Requirements in NERC’s Reliability Standards.”

## 5. Background:

- 5.1.1. This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

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<sup>3</sup> “Clear line of sight” means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.



- 5.1.2.** a) Performance-based — defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome?*
- 5.1.3.** b) Risk-based — preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?*
- 5.1.4.** c) Competency-based — defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?*
- 5.1.5.** The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

**5.1.6.** For this standard, the requirements have been developed as follows:

**5.1.7.** Performance-based: Requirements 1 and 2

- 5.1.8.** Competency-based: Requirement 3
- 5.1.9.** Risk-based: Requirements 4, 5, 6 and 7
- 5.1.10.** R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.
- 5.1.11.** Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term “public lands” includes municipal lands, village lands, city lands, and a host of other governmental entities.
- 5.1.12.** This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.
- 5.1.13.** This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.
- 5.1.14.** Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system

loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

## B. Requirements and Measures

**R1.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below<sup>4</sup> [*Violation Risk Factor: High*] [*Time Horizon: Real-time*]:

1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage<sup>5</sup>,
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage<sup>6</sup>,
3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage<sup>4</sup>,
4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage<sup>4</sup>.

**M1.** Each applicable Transmission Owner

### Rationale for R1 and R2:

Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable Transmission Owner's or applicable Generator Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.
2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

<sup>4</sup> This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.

<sup>5</sup> If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

<sup>6</sup> Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

- R2.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below<sup>2</sup> [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time*]:
1. An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage<sup>3</sup>,
  2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage<sup>4</sup>,
  3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage<sup>4</sup>,
  4. An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage<sup>4</sup>
- M2.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)

**R3.** Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following:

**3.1** Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;

**3.2** Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]:

**Rationale**

The documentation provides a basis for evaluating the competency of the applicable Transmission Owner’s or applicable Generator Owner’s vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions. See Figure

**M3.** The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

**R4.** Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment [Violation Risk Factor: Medium] [Time Horizon: Real-time].

**Rationale**

This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

**M4.** Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

**R5.** When a applicable Transmission Owner and applicable Generator Owner is constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

**Rationale**

Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

**M5.** Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

**R6.** Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW<sup>7</sup> [*Violation Risk Factor:*

**Rationale**

Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could

<sup>7</sup> When the applicable Transmission Owner or applicable Generator Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.



*Medium*] [*Time Horizon: Operations Planning*].

**M6.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

**R7.** Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan

**Rationale**

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

(measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

- Change in expected growth rate/ environmental factors
- Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner<sup>8</sup>
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Emerging technologies

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<sup>8</sup> Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.



- M7.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records.  
(R7)

## C. Compliance

### 1. Compliance Monitoring Process

#### 1.1 Compliance Enforcement Authority

#### 1.2 Regional Entity Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, Measures M1, M2, M3, M5, M6 and M7 for three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.3 Compliance Monitoring and Enforcement Processes:

5.1.15. Compliance Audit

5.1.16. Self-Certification

5.1.17. Spot Checking

5.1.18. Compliance Violation Investigation

5.1.19. Self-Reporting

Complaint

Periodic Data Submittal

#### 1.4 Additional Compliance Information

***Periodic Data Submittal:*** The applicable Transmission Owner and applicable Generator Owner will submit a quarterly report to its Regional Entity, or the Regional Entity’s designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

**Table of Compliance Elements**

On November 3, NERC’s Board of Trustees adopted FAC-003-2—Transmission Vegetation Management with NERC staff proposed changes to the VSLs for R1 and R2 in lieu of the Project 2007-07 SDT’s original proposed VSLs. The table below now reflects the VSLs for R1 and R2 that were approved by NERC’s Board of Trustees. The only additional change made by the Project 2010-07 SDT was to change “Transmission Owner” to “responsible entity.”

R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Real-time	High			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following: <ul style="list-style-type: none"> <li>• A fall-in from inside the active transmission line ROW</li> <li>• Blowing together of applicable lines and vegetation located inside the active transmission line ROW</li> <li>• A grow-in</li> </ul>
R2	Real-time	Medium			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and	The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and

					encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.	a vegetation-related Sustained Outage was caused by one of the following: <ul style="list-style-type: none"> <li>• A fall-in from inside the active transmission line ROW</li> <li>• Blowing together of applicable lines and vegetation located inside the active transmission line ROW</li> <li>• A grow-in</li> </ul>
R3	Long-Term Planning	Lower		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity's applicable lines. (Requirement R3, Part 3.2)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines. Requirement R3, Part 3.1)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity's applicable lines.
R4	Real-time	Medium			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5	Operations Planning	Medium				The responsible entity did not take corrective action when it

						was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6	Operations Planning	Medium	The responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7	Operations Planning	Medium	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Differences

None.

E. Interpretations

None.

F. Associated Documents

Guideline and Technical Basis (attached).

## Guideline and Technical Basis

### Effective dates:

The first two sentences of the Effective Dates section is standard language used in most NERC standards to cover the general effective date and is sufficient to cover the vast majority of situations. Five special cases are needed to cover effective dates for individual lines which undergo transitions after the general effective date. These special cases cover the effective dates for those lines which are initially becoming subject to the standard, those lines which are changing their applicability within the standard, and those lines which are changing in a manner that removes their applicability to the standard.

Case 1 is needed because the Planning Coordinators may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2011 may identify a line to have that designation beginning in PY 2021, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. The table below has some explanatory examples of the application.

<u>Date that Planning Study is completed</u>	<u>PY the line will become an IROL element</u>	<u>Date 1</u>	<u>Date 2</u>	<u>Effective Date The latter of Date 1 or Date 2</u>
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Case 2 is needed because a line operating below 200kV designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Case 3 is needed because a line operating at 200 kV or above that once was designated as an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network. Such changes result in the need to apply R1 to that line until that date is reached and then to apply R2 to that line thereafter.

Case 4 is needed because an existing line that is to be operated at 200 kV or above can be acquired by an applicable Transmission Owner or applicable Generator Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network which will thereafter make the line subject to the standard.

Case 5 is needed because an existing line that is operated below 200 kV can be acquired by an applicable Transmission Owner or applicable Generator Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network. In this special case the line upon acquisition was designated as an element of an Interconnection Reliability Operating Limit (IROL) or an element of a Major WECC Transfer Path.

### **Defined Terms:**

#### **Explanation for revising the definition of ROW:**

The current NERC glossary definition of Right of Way has been modified to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This modified definition represents a slight but significant departure from the strict legal definition of “right of way” in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the revised definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.



### **Explanation for revising the definition of Vegetation Inspections:**

The current glossary definition of this NERC term is being modified to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

### **Explanation of the definition of the MVCD:**

The MVCD is a calculated minimum distance that is derived from the Gallet Equations. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 below provides MVCD values for various voltages and altitudes. Details of the equations and an example calculation are provided in Appendix 1 of the Technical Reference Document.

### **Requirements R1 and R2:**

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each applicable Transmission Owner or applicable Generator Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element of an IROL or Major WECC Transfer Path. R2 is applicable to all other lines that are not elements of IROLs, and not elements of Major WECC Transfer Paths.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations as described more fully in the Technical Reference document.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will prevent transmission outages.

If the applicable Transmission Owner or applicable Generator Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

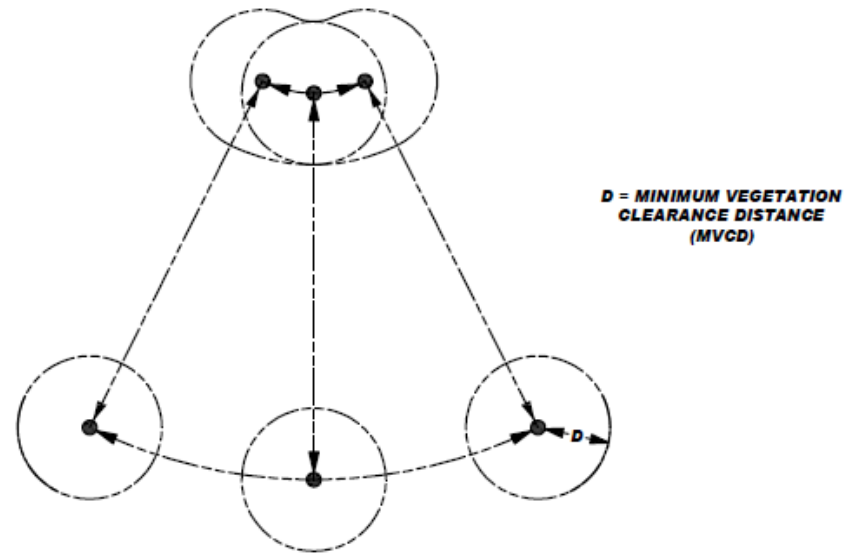
**Requirement R3:** R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable Transmission Owner or applicable Generator Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an applicable Transmission Owner or applicable Generator Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below. In the Technical Reference document more figures and explanations of conductor dynamics are provided.



**Figure 1**

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

**Requirement R4:**

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner or applicable Generator Owner employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

**Requirement R5:**

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the applicable Transmission Owner or applicable Generator Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The applicable Transmission Owner or applicable Generator Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

**Requirement R6:**

R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner’s ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission Owner or applicable Generator Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be  $100/2000 = 0.05$  or 5%. The “Low VSL” for R6 would apply in this example.

**Requirement R7:**

R7 is a risk-based requirement. The applicable Transmission Owner or applicable Generator Owner is required to complete its annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a “span-by-span”, or even a “line-by-line” detailed description of all work to be performed. It is only intended to require that the applicable Transmission Owner or applicable Generator Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

For example, when an applicable Transmission Owner or applicable Generator Owner identifies 1,000 miles of applicable transmission lines to be completed in the applicable Transmission Owner’s or applicable Generator Owner’s annual plan, the applicable Transmission Owner or applicable Generator Owner will be responsible completing those identified miles. If a applicable Transmission Owner or applicable Generator Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be:  $1000 - 100$  (deferred miles) = 900 modified annual plan, or  $900 / 900 = 100\%$  completed annual miles. If an applicable Transmission Owner or applicable Generator Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be:  $1000 - 875 = 125$  miles failed to complete then,  $125$  miles (not completed) /  $1000$  total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner’s or applicable Generator Owner’s system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.

In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner’s or applicable Generator Owner’s easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.





**FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)<sup>9</sup>  
For Alternating Current Voltages (feet)**

( AC ) Nominal System Voltage (KV)	( AC ) Maximum System Voltage (KV) <sup>10</sup>	MVCD (feet)  Over sea level up to 500 ft	MVCD (feet)  Over 500 ft up to 1000 ft	MVCD feet  Over 1000 ft up to 2000 ft	MVCD feet  Over 2000 ft up to 3000 ft	MVCD feet  Over 3000 ft up to 4000 ft	MVCD feet  Over 4000 ft up to 5000 ft	MVCD feet  Over 5000 ft up to 6000 ft	MVCD feet  Over 6000 ft up to 7000 ft	MVCD feet  Over 7000 ft up to 8000 ft	MVCD feet  Over 8000 ft up to 9000 ft	MVCD feet  Over 9000 ft up to 10000 ft	MVCD feet  Over 10000 ft up to 11000 ft
765	800	8.2ft	8.33ft	8.61ft	8.89ft	9.17ft	9.45ft	9.73ft	10.01ft	10.29ft	10.57ft	10.85ft	11.13ft
500	550	5.15ft	5.25ft	5.45ft	5.66ft	5.86ft	6.07ft	6.28ft	6.49ft	6.7ft	6.92ft	7.13ft	7.35ft
345	362	3.19ft	3.26ft	3.39ft	3.53ft	3.67ft	3.82ft	3.97ft	4.12ft	4.27ft	4.43ft	4.58ft	4.74ft
287	302	3.88ft	3.96ft	4.12ft	4.29ft	4.45ft	4.62ft	4.79ft	4.97ft	5.14ft	5.32ft	5.50ft	5.68ft
230	242	3.03ft	3.09ft	3.22ft	3.36ft	3.49ft	3.63ft	3.78ft	3.92ft	4.07ft	4.22ft	4.37ft	4.53ft
161*	169	2.05ft	2.09ft	2.19ft	2.28ft	2.38ft	2.48ft	2.58ft	2.69ft	2.8ft	2.91ft	3.03ft	3.14ft
138*	145	1.74ft	1.78ft	1.86ft	1.94ft	2.03ft	2.12ft	2.21ft	2.3ft	2.4ft	2.49ft	2.59ft	2.7ft
115*	121	1.44ft	1.47ft	1.54ft	1.61ft	1.68ft	1.75ft	1.83ft	1.91ft	1.99ft	2.07ft	2.16ft	2.25ft
88*	100	1.18ft	1.21ft	1.26ft	1.32ft	1.38ft	1.44ft	1.5ft	1.57ft	1.64ft	1.71ft	1.78ft	1.86ft
69*	72	0.84ft	0.86ft	0.90ft	0.94ft	0.99ft	1.03ft	1.08ft	1.13ft	1.18ft	1.23ft	1.28ft	1.34ft

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

<sup>9</sup> The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

<sup>10</sup> Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

**TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)<sup>7</sup>  
For Alternating Current Voltages (meters)**

( AC ) Nominal System Voltage (KV)	( AC ) Maximum System Voltage <sup>8</sup> (kV)	MVCD meters  Over sea level up to 152.4 m	MVCD meters  Over 152.4 m up to 304.8 m	MVCD meters  Over 304.8 m up to 609.6m	MVCD meters  Over 609.6m up to 914.4m	MVCD meters  Over 914.4m up to 1219.2m	MVCD meters  Over 1219.2m up to 1524m	MVCD meters  Over 1524 m up to 1828.8 m	MVCD meters  Over 1828.8m up to 2133.6m	MVCD meters  Over 2133.6m up to 2438.4m	MVCD meters  Over 2438.4m up to 2743.2m	MVCD meters  Over 2743.2m up to 3048m	MVCD meters  Over 3048m up to 3352.8m
765	800	2.49m	2.54m	2.62m	2.71m	2.80m	2.88m	2.97m	3.05m	3.14m	3.22m	3.31m	3.39m
500	550	1.57m	1.6m	1.66m	1.73m	1.79m	1.85m	1.91m	1.98m	2.04m	2.11m	2.17m	2.24m
345	362	0.97m	0.99m	1.03m	1.08m	1.12m	1.16m	1.21m	1.26m	1.30m	1.35m	1.40m	1.44m
287	302	1.18m	0.88m	1.26m	1.31m	1.36m	1.41m	1.46m	1.51m	1.57m	1.62m	1.68m	1.73m
230	242	0.92m	0.94m	0.98m	1.02m	1.06m	1.11m	1.15m	1.19m	1.24m	1.29m	1.33m	1.38m
161*	169	0.62m	0.64m	0.67m	0.69m	0.73m	0.76m	0.79m	0.82m	0.85m	0.89m	0.92m	0.96m
138*	145	0.53m	0.54m	0.57m	0.59m	0.62m	0.65m	0.67m	0.70m	0.73m	0.76m	0.79m	0.82m
115*	121	0.44m	0.45m	0.47m	0.49m	0.51m	0.53m	0.56m	0.58m	0.61m	0.63m	0.66m	0.69m
88*	100	0.36m	0.37m	0.38m	0.40m	0.42m	0.44m	0.46m	0.48m	0.50m	0.52m	0.54m	0.57m
69*	72	0.26m	0.26m	0.27m	0.29m	0.30m	0.31m	0.33m	0.34m	0.36m	0.37m	0.39m	0.41m

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)<sup>7</sup>  
 For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)
	Over sea level up to 500 ft	Over 500 ft up to 1000 ft	Over 1000 ft up to 2000 ft	Over 2000 ft up to 3000 ft	Over 3000 ft up to 4000 ft	Over 4000 ft up to 5000 ft	Over 5000 ft up to 6000 ft	Over 6000 ft up to 7000 ft	Over 7000 ft up to 8000 ft	Over 8000 ft up to 9000 ft	Over 9000 ft up to 10000 ft	Over 10000 ft up to 11000 ft
	(Over sea level up to 152.4 m)	(Over 152.4 m up to 304.8 m)	(Over 304.8 m up to 609.6m)	(Over 609.6m up to 914.4m)	(Over 914.4m up to 1219.2m)	(Over 1219.2m up to 1524m)	(Over 1524 m up to 1828.8 m)	(Over 1828.8m up to 2133.6m)	(Over 2133.6m up to 2438.4m)	(Over 2438.4m up to 2743.2m)	(Over 2743.2m up to 3048m)	(Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

**Notes:**

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet Equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 uses the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-01 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines, as such, are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line is approximately 2.0 per unit. This value is a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the

maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below is considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit is considered a realistic maximum.

The Gallet Equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet Equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

While EPRI is currently trying to establish empirical data for spark-over distances to live vegetation, there are no spark-over formulas currently derived expressly for vegetation to conductor minimum distances. Therefore the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice. The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

**Comparison of spark-over distances computed using Gallet wet equations vs.  
IEEE 516-2003 MAID distances**

( AC ) Nom System Voltage (kV)	( AC ) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 feet	Table 7 (Table D.5 for feet) IEEE 516-2003 MAID (ft) @ Alt. 3000 feet
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

## **Implementation Plan for FAC-003-X – Transmission Vegetation Management Program**

### **Prerequisite Approvals**

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

### **Revision to Sections of Approved Standards and Definitions**

There are no proposed revisions to requirements in other already approved standards. FAC-003-1 will be retired at midnight the day before FAC-003-X becomes effective.

There is one revised definition in the proposed standard:

**Right-of-Way:** A corridor of land on which electric lines may be located. The Transmission Owner or applicable Generator Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

The current glossary definition of Right-of-Way will be retired at midnight the day before FAC-003-X (and with it, the above definition of Right-of-Way) becomes effective.

### **Compliance with Standard**

There are no changes to the requirements applicable to Transmission Owners already in effect in FAC-003-1, and the expectation is that Transmission Owners will maintain their current state of compliance. Thus, the standard is effective for Transmission Owners upon approval, as detailed below.

The proposed changes to FAC-003-1 only address Generator Owner applicability and requirements (add Generator Owner to section 4.3 and add applicable Generator Owner to all requirements). Therefore, this implementation plan only identifies a compliance timeframe for Generator Owners to which this standard will apply.

To reach compliance with the standard, a Generator Owner will have to perform a full review of as-built drawings and determine which generation interconnection Facilities require a Transmission Vegetation Management Plan (TVMP) and inspection as specified by NERC Reliability Standard FAC-003-X. In general, Generator Owners do not have staff that are qualified and experienced to create a TVMP and implement annual plans for vegetation management. Once a complete inventory is created, the Generator Owner will begin the process of gathering information for the TVMP. In instances where the generation interconnection Facilities are owned by a partnership, a majority or operating partner will need to obtain partnership approval to proceed with procurement of a TVMP expert, and later a tree trimming crew. Typically, a request for proposal to hire TVMP consultant is initiated, which could take several weeks in order to obtain sufficient bids (and also satisfy Sarbanes Oxley requirements). Once all bids have been received, a contract with a TVMP consultant is signed. At this point, the TVMP consultant and



Generator Owner staff will develop the TVMP, which needs to take into account local growth conditions, types of vegetation and other aspects required by FAC-003-X. Once the TVMP is developed, Generator Owner staff and the TVMP consultant will need to perform a Right-of-Way inspection, usually done using GPS, LIDAR and other tools by experienced and qualified staff.

Once a Right-of-Way inspection is completed and clearances are required, the Generator Owner will need to issue a request for proposal to hire a tree trimming crew that is qualified and experienced to perform required clearance trimming. Once all bids have been received, a contract with a tree trimming crew is signed. When the tree trimming crew is acquired, the crew will need to familiarize themselves with the entity's TVMP and required clearances. The Generator Owner will typically need to schedule any required outages in order for the tree trimming crew to perform the needed clearance trimming. This action would also include the implementation of the work plan. During scheduled outages, if required, the tree trimming crew will perform any required clearances and document the activities.

Another typical action is the Generator Owner establishing a system for maintaining TVMP-related activities, including maintenance of inspection and clearance documentation. On an ongoing basis, in addition to performing inspections and clearances as required by the entity's TVMP, the Generator Owner will need to ensure that the training and qualification requirements for the standard are met. The entity will also need to maintain documentation of all FAC-003-X activities for compliance period of one year to meet compliance with the standard.

Again, due to a typical lack of experience and qualifications required by FAC-003-X, compliance with this standard by a Generator Owner may take as long as two years – in part because many entities will have generator interconnection Facilities in various parts of the country which may require several instances of TVMP and numerous Right-of-Way inspections.

### **Effective Date**

There are three effective dates associated with this implementation plan:

The first effective date applies to Transmission Owners.

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner become effective upon Board of Trustees' adoption.

The second effective date allows Generator Owners time to prepare a formal transmission vegetation management program as outlined in Requirement R1.

In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The third effective date allows entities time to comply with Requirements R2, R3, and R4.

In those jurisdictions where regulatory approval is required, Requirements R2, R3, and R4 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R2, R3, and R4 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

# Implementation Plan for FAC-003-3 — Transmission Vegetation Management

## Prerequisite Approvals

There are a number of scenarios that could occur regarding the approval of FAC-003-2 that would affect the implementation of FAC-003-3.

If FAC-003-2 is filed with applicable regulatory authorities and approved before FAC-003-3 is filed with applicable regulatory authorities, then when and if FAC-003-3 is approved by applicable regulatory authorities, the implementation plan and effective dates for Transmission Owners in FAC-003-2 will be transferred into this implementation plan. The “clock” for calculating effective dates for Transmission Owners will still have started at the time specified in FAC-003-2 (based on the approval date of that standard). Generator Owners will be required to comply with the implementation plan as outlined below.

If applicable regulatory authorities elect to approve only FAC-003-3 and not FAC-003-2, the original implementation plan for Transmission Owners as outlined in FAC-003-2 will be transferred into this implementation plan. Generator Owners will be required to comply with the implementation plan as outlined below. The “clocks” for calculating the effective dates for both Transmission Owners and Generator Owners will begin at the same time.

If applicable regulatory authorities approve FAC-003-2 and FAC-003-3 at the same time, the implementation plan and effective dates for Transmission Owners in FAC-003-2 will be transferred into this implementation plan and FAC-003-2 will be immediately retired. Generator Owners will be required to comply with the implementation plan as outlined below. The “clocks” for calculating the effective dates for both Transmission Owners and Generator Owners will begin at the same time.

## Revision to Sections of Approved Standards and Definitions

There are no proposed revisions to requirements in other already approved standards. All requirements and the two revised definitions in the proposed standard FAC-003-2 will be retired at midnight the day before FAC-003-3 becomes effective.

There are two revised definitions in the proposed standard:

### Right-of-Way (ROW)

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either

construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria.

### **Vegetation Inspection**

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

There is one new definition in the proposed standard:

### **Minimum Vegetation Clearance Distance (MVCD)**

The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

The current glossary definitions of Right-of-Way and Vegetation Inspection, or the glossary definitions of Right-of-Way and Vegetation Inspection in FAC-003-2, if that standard has been approved, will be retired at midnight the day before FAC-003-3 (and with it, the above definitions of Right-of-Way and Vegetation Inspection) becomes effective. The above definition of Minimum Vegetation Clearance Distance will be added to the NERC glossary upon approval of FAC-003-3, or the above definition of Minimum Vegetation Clearance Distance will replace (and thus force the retirement, at midnight the day before FAC-003-3 is approved) of the same definition in FAC-003-2, if FAC-003-2 has been approved.

### **Compliance with Standard**

As outlined above under "Prerequisite Approvals," the inclusion of Transmission Owners in this implementation plan will depend on order in which regulatory authorities approved FAC-003-2 and FAC-003-3. Therefore, this implementation plan only identifies a compliance timeframe for Generator Owners to which this standard will apply.

To reach compliance with the standard, a Generator Owner will have to perform a full review of as-built drawings and determine which generation interconnection Facilities require a Transmission Vegetation Management Plan (TVMP) and inspection as specified by NERC Reliability Standard FAC-003-3. In general, Generator Owners do not have staff that are qualified and experienced to create a TVMP, perform Right-of-Way inspections, and perform any required tree trimming (as is required by FAC-003-3 Requirement 1.3). Once a complete inventory is created, the Generator Owner will begin the process of gathering information for the TVMP. In instances where the generation interconnection Facilities are owned by a partnership, a majority or operating partner will need to obtain partnership approval to proceed with procurement of a TVMP expert, and later a tree trimming crew. Typically, a

request for proposal to hire TVMP consultant is initiated which could take several weeks in order to obtain sufficient bids (and also satisfy Sarbanes Oxley requirements). Once all bids have been received, a contract with a TVMP consultant is signed. At this point, the TVMP consultant and Generator Owner staff will develop the TVMP, which needs to take into account local growth conditions, types of vegetation and other aspects required by FAC-003. Once the TVMP is developed, Generator Owner staff and the TVMP consultant will need to perform a Right-of-Way inspection (as required in FAC-003-3 Requirement 1), usually done using GPS, LIDAR and other tools by experienced and qualified staff.

Once a Right-of-Way inspection is completed and clearances are required, the Generator Owner will need to issue a request for proposal to hire a tree trimming crew that is qualified and experienced to perform required clearance trimming. Once all bids have been received, a contract with a tree trimming crew is signed. When the tree trimming crew is acquired, the crew will need to familiarize themselves with the entity's TVMP and required clearances. The Generator Owner will typically need to schedule any required outages in order for the tree trimming crew to perform the needed clearance trimming. This action would also include the implementation of the work plan as required in FAC-003-3 Requirement 2. During scheduled outages, if required, the tree trimming crew will perform any required clearances and document the activities.

Another typical action is the Generator Owner establishing a system for maintaining TVMP-related activities, including maintenance of inspection and clearance documentation (as required in FAC-003-3 Requirement 1.2). On an ongoing basis, in addition to performing inspections and clearances as required by the entity's TVMP, the Generator Owner will need to ensure that the training and qualification requirements for the standard are met. The entity will also need to maintain documentation of all FAC-003-3 activities for compliance period of one year to meet compliance with the standard.

Again, due to a typical lack of experience and qualifications required by FAC-003-3, compliance with this standard by a Generator Owner may take as long as two years – in part because many entities will have generator interconnection Facilities in various parts of the country which may require several instances of TVMP and numerous Right-of-Way inspections.

### **Effective Date**

There are two effective dates associated with this implementation plan:

The first effective date allows Generator Owners time to develop documented maintenance strategies or procedures or processes or specifications as outlined in Requirement R3.

In those jurisdictions where regulatory approval is required, Requirement R3 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities

where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.

The second effective date allows entities time to comply with Requirements R1, R2, R4, R5, R6, and R7.

In those jurisdictions where regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 become effective on the first day of the first calendar quarter two years following Board of Trustees adoption.

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.
2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.
3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.
4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.
5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

# Unofficial Comment Form

## Generator Requirements at the Transmission Interface (Project 2010-07)

Please **DO NOT** use this form to submit comments. Please use the [electronic comment form](#) to submit comments on the first formal posting for Project 2010-07—Generator Requirements at the Transmission Interface. The electronic comment form must be completed by **April 09, 2012**.

[2010-07 Project Page](#)

If you have questions please contact Mallory Huggins at [mallory.huggins@nerc.net](mailto:mallory.huggins@nerc.net) or 202-644-8062.

### Background

The purpose of Project 2010-07 is to ensure that all generator-owned Facilities are appropriately covered under NERC's Reliability Standards. While many Generator Owners and Generator Operators operate Elements and Facilities that are considered by some entities to be Transmission, these are most often radial Facilities that are not part of the integrated grid, and as such should not be subject to the same standards applicable to Transmission Owners and Transmission Operators who own and operate Transmission Elements and Facilities that are part of the integrated grid.

As part of the BES, generators affect the overall reliability of the BES. However, registering a Generator Owner or Generator Operator as a Transmission Owner or Transmission Operator, as has been the solution in some cases in the past, may decrease reliability by diverting the Generator Owner's or Generator Operator's resources from the operation of the equipment that actually produces electricity – the generation equipment itself.

The drafting team's goal is to ensure that an adequate level of reliability is maintained in the BES by clearly describing which standards need to be applied to generator interconnection Facilities that are not already applicable to Generator Owners or Generator Operators.

On January 20, 2012, Exelon submitted a [Level One Appeal of the standard process for FAC-003-3 and FAC-003-X](#) to NERC's Vice President of Standards and Training that stated the following: "Exelon believes that the NERC Standards Process Manual was not followed, and that based on the substantive changes made to both Standards following the Initial Ballot, NERC should have set the Standards for vote using a Successive Ballot rather than a Recirculation Ballot."

NERC's Vice President of Standards and Training submitted [a timely response](#) to the appeal that found that "Exelon...made its case that the [Standard Processes Manual] was not adhered to and that a change impacting applicability was made between the last successive and recirculation ballot." Accordingly, the Vice President of Standards and Training referred the issue to the Standards Committee for handling, suggesting the following options:



1. Re-post the standard for a successive ballot and recirculation ballot. Essentially set the clock back and correctly replay the last steps of the process.
2. Ask the SDT to remove the clarification language from the final standard and go directly to recirculation ballot.
3. Ask the SDT to redesign the challenged portion of the proposed standard.

He recommended that the Standards Committee pursue option 2. In a Standards Committee Executive Committee (SCEC) conference call on February 23, 2012, the SCEC directed NERC staff to void the FAC-003-3 and FAC-003-X recirculation ballot results of December 2011 and “remand the work to the drafting team with direction to take into account the issues raised in the Exelon appeal submitted in response to the recirculation ballot previously conducted and either: modify the language added following the initial ballot and then re-post the standard for a successive ballot, or remove the language added following the initial ballot and go directly to recirculation ballot.”

The Project 2010-07 SDT considered Exelon’s appeal in the context of other stakeholder comments submitted in the first successive ballot between October 5 and November 18, 2011. The SDT continues to believe that a reference to line of sight is clarifying and makes explicit the SDT’s implicit intent from day one. Thus, it kept the line of sight reference but made a few additional changes for formatting clarity and language consistency. The team also added a footnote to further explain what it means by “line of sight.”

Additionally, “Regional Entity” was removed from the Applicability section of FAC-003-X because it is not a Functional Entity according to the Functional Model.

The FAC-003-3 and FAC-003-X recirculation ballot results of December 2011 have been voided, and both standards are being posted for a 30-day concurrent comment period and successive ballot to allow stakeholders the opportunity to comment on these changes.

The appeal and NERC response are posted on the [2010-07 project page](#).

Status of other standards that are part of Project 2010-07:

- FAC-001-1 and PRC-004-2.1a were adopted by NERC’s Board of Trustees on February 9, 2012
- PRC-005-1.1a is currently posted for a 45-day concurrent comment and initial ballot.

No standards modified under Project 2010-07 will be filed with regulatory authorities until the Board of Trustees has acted on the complete package of four standards.



**You do not have to answer all questions. Enter all comments in Simple Text Format.**

1. The Project 2010-07 SDT considered Exelon's appeal in the context of other stakeholder comments submitted in the first successive ballot between October 5 and November 18, 2011, along with advice from NERC staff. The SDT continues to believe that a reference to line of sight is clarifying and makes explicit the SDT's implicit intent from day one. Thus, it kept the line of sight reference but made a few additional changes for formatting clarity and language consistency. The team also added a footnote to further explain what it means by "line of sight." Do you agree with these changes? If not, please provide specific alternative language.

Yes

No

Comments:

# Approved Meeting Minutes

## Standards Committee Executive Committee

February 23, 2012 | 1:00 p.m. Eastern

### 1. Administrative Items

#### a. Introductions and Quorum

Allen Mosher welcomed all and verified there was a quorum with four of the five Standards Committee Executive Committee members present.

Standards Committee Executive Committee members attending:

- John Bussman, Associated Electric Cooperative Inc.
- David Kiguel, Hydro One Networks Inc.
- Allen Mosher, American Public Power Association
- Jason Shaver, American Transmission Company

Additional Standards Committee members in attendance:

- Michael Gildea, Dominion Resources Services, Inc.
- Scott Miller, MEAG Power
- Fled Plett, MA Attorney General
- Joseph Tarantino, SMUD

Also attending:

- James Case, Entergy
- Juan Diaz, Customized Energy Solutions
- Andrew Dressel, NERC
- José H. Escamilla, CPS Energy
- Laura Lee, Duke Energy
- Maureen Long, NERC
- Jason Marshall, ACEs Power
- Steven Naumann, Exelon Corporation
- Jerry Parnell, City Water, Light & Power
- Robert Rhodes, SPP
- Andy Rodriguez, NERC
- Herbert Schrayshuen, NERC
- Louis Slade, Dominion Resources
- David Taylor, NERC
- Rick Terrill, Luminant Power

a. **Conference Call Reminder and Antitrust Guidelines**

Maureen Long reminded all that the conference call was open to all interested parties and reviewed the NERC Antitrust Compliance Guidelines.

2. **Level 1 Appeal of FAC-003-3 and FAC-003x in Project 2010-07**

Between the initial and recirculation ballots, the drafting team working on Project 2010-07 – Generator Requirements at the Transmission Interface made an identical modification to two standards (FAC-003-3 and FAC-003-x). While the drafting team felt that the modification was not significant, Exelon did consider the modification as “significant” and filed an appeal. Herbert Schrayshuen reviewed available evidence from the appellant, the drafting team, and the standards staff and concluded that the change made to the standards did change the scope of applicability and the standards should have been posted for successive rather than recirculation ballots. The chair of the SC, Allen Mosher came to the same conclusion.

After discussion of available options, John Bussman motioned to direct the standards staff to void the recirculation ballot results for FAC-003-3 and FAC-003-x and remand the work to the SDT with direction to take into account the issues raised in the Exelon appeal and either:

- Modify the language added following the initial ballot and then post the standard for a successive ballot, or
  - Remove the language added following the initial ballot and go directly to recirculation ballot.
- *The motion was approved without objection or abstention.*

3. **Adjourn**

March 6, 2012

Louis Slade  
Dominion Resources  
120 Tredegar St.  
Richmond, VA 23219

Dear Louis,

The purpose of this letter is to advise the members of the Generator Requirements at the Transmission Interface Standard Drafting Team of the results of a Level 1 Appeal of the recirculation ballots conducted for FAC-003-3 and FAC-003-x. The Appeal was filed on behalf of Exelon Corporation, alleging that the drafting team made a substantive change to both FAC-003-3 and FAC-003-x between the initial and the recirculation ballots.

In accordance with the Standard Processes Manual, the appeal was submitted to Herbert Schrayshuen, NERC's Vice President of Standards and Training. Mr. Schrayshuen reviewed available evidence from the appellant, the drafting team, and the standards staff and concluded that the change made to the standards prior to the recirculation ballot did change the scope of applicability and he ruled that the standards should have been posted for successive rather than recirculation ballots.


On February 23, 2012 the Standards Committee's Executive Committee (SCEC) reviewed the results of Mr. Schrayshuen's findings and agreed with Mr. Schrayshuen's conclusions. As a result, the SCEC directed the standards staff to void the results of the recirculation ballots for FAC-003-3 and FAC-003-x and, through this letter, is remanding FAC-003-3 and FAC-003-x to the Project 2010-07 – Generator Requirements at the Transmission Interface Standard Drafting Team. The SCEC directs the drafting team to take into account the issues raised in the Exelon appeal and either:

- Modify the language added following the initial ballot and then post the standard for a successive ballot, or
- Remove the language added following the initial ballot and go directly to recirculation ballot.

Thank you in advance for your prompt attention to these issues and for the GO-TO Standard Drafting Team's commitment of time and energy to reliable operations and the resolution of stakeholder concerns through the NERC standards process. Please do not hesitate to contact me or NERC standards staff should you have any questions.

3353 Peachtree Road NE  
Suite 600, North Tower  
Atlanta, GA 30326  
404-446-2560 | [www.nerc.com](http://www.nerc.com)

Sincerely,

A handwritten signature in black ink that reads "Allen Mosher". The signature is fluid and cursive, with the first name "Allen" and last name "Mosher" clearly legible.

Allen Mosher  
Standards Committee Chair

cc: Herbert Schrayshuen  
Steven T. Naumann

# Technical Justification Resource Document

## Project 2010-07 Generator Requirements at the Transmission Interface

### Background

As part of its work on Project 2010-07—Generator Requirements at the Transmission Interface, the standard drafting team (SDT) reviewed 34 reliability standards and 102 requirements to determine what changes are necessary to close a reliability gap with respect to what is commonly known as the generator interconnection Facility. Many of these standards and requirements had been addressed in the [Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface](#) (Ad Hoc Report) and additional standards were reviewed as a result of informal discussions with NERC and FERC staffs.

The SDT's technical justification document has not changed substantively since it was posted in December 2011, but the document below has been updated to reflect the posted changes to FAC-003-3 and FAC-003-X.

The basis for standard modifications recommended by the Ad Hoc Group for Generator Requirements at the Transmission Interface (Ad Hoc Group) was a few fundamental clarifications to the definitions of Generator Owner, Generator Operator, and Transmission, along with the creation of new definitions: one for Generator Interconnection Facility and one for Generator Interconnection Operational Interface. The Ad Hoc Group proposed the addition of these two new definitions to 26 standards encompassing 29 requirements (new and old), along with some modifications to FAC-003 to make it applicable to Generator Owners under certain circumstances.

Since the publication of the Ad Hoc Report, various entities have challenged these modifications and the recommended creation of the new definitions. The SDT has developed a more focused approach than that of the Ad Hoc Group: to propose recommendations whereby sole-use interconnection Facilities (at or above 100 kV) that are owned and operated by generating entities will be included in a small set of standards and requirements previously only applicable to Transmission Owners. The SDT agrees completely with the Ad Hoc Group's conclusion that Generator Owners and Operators of these sole-use generator tie-line Facilities (at voltages equal to or greater than 100 kV) should not be registered as Transmission Owners and Transmission Operators in order to maintain reliability on the Bulk Electric System (BES).

The SDT's justification for this strategy is rooted in the very title of its standards project: "Generator Requirements at the Transmission Interface." That is, the goal and scope of the project has always been to determine the responsibilities of those Generator Owners and Generator Operators that own or operate an interconnection Facility (in some cases labeled a "transmission Facility") between the generator and the interface with the portion of the BES where Transmission Owners and Transmission

Operators take over ownership and operating responsibility. These kinds of Generator Owners and Generator Operators do not own or operate Facilities that are part of the interconnected system; rather, they own and operate sole-use Facilities that are connected to the boundary of the interconnected system and as such have a limited role in providing reliability compared to those that operate in a networked fashion beyond the point of interconnection.

While some argue that these interconnecting portions of a Generator Owner's Facilities could be defined as Transmission and thus require the Generator Owner and Generator Operator for the Facility to be classified and registered as a Transmission Owner and Transmission Operator, the SDT does not believe this is necessary to provide an appropriate level of reliability for the BES. Just as important, such classification and registration could actually cause a reduction in reliability. Generator Owners and Generator Operators do not need, and in some cases may be prohibited from having, a wide-area view and responsibility for the integrated transmission system. Requiring Generator Owners and Generator Operators to have such responsibilities would require significant training, require substantially more data and modeling responsibilities, and detract from the entities' primary functions: to own and operate their generation equipment – including any Facilities owned and operated at voltages of 100 kV or greater that connect to the interconnected system – in a reliable manner.

Additionally, the SDT believes that the industry is much more aware today of the need to include *all* elements (owned and operated at 100 kV or higher) of a generator Facility in the procedures and compliance program of the registered entity that owns or has operational responsibility of those elements. Industry awareness was raised substantially at the time the [October 17, 2010 Facility Ratings Recommendation to Industry](#) was issued (which included Generator Owners and specifically addressed interconnection Facilities in [the Q&A document](#) with the statement that the alert applied to generator interconnection tie lines that are radial only and do not serve load “if the generator is considered part of the bulk electric system”). While this applies to a specific NERC Recommendation, the SDT considers this compelling evidence that the paradigm for thinking about generator interconnection Facilities is shifting.

All of this has led the SDT to its current conclusions to modify FAC-001, FAC-003, and PRC-004 and later, PRC-005. The SDT does not believe any further modifications to standards are necessary to maintain an appropriate level of reliability based on the revised assumption that while generator Facilities (at 100 kV and above) will be considered by some to be transmission, Generator Owners and Generator Operators should not be registered as Transmission Owners and Transmission Operators simply as a result of the ownership and operation of such Facilities. Because the majority of commenters support the SDT's current recommendation to not adopt new terms, the SDT has elected to focus on its standard changes and not, at this time, propose revisions to existing, or creation of new, glossary terms.

Below, the SDT discusses the changes it has proposed for FAC-001, FAC-003, and PRC-004 and the changes it plans to propose for PRC-005 and then provides justification for not modifying any of the additional standards and requirements it has reviewed.

## **Review of SDT's Proposed Standard Changes**

### ***FAC-001-1—Facility Connection Requirements***

While some stakeholders have questioned the modifications in the proposed FAC-001-1, the SDT remains convinced that there is the potential for a reliability gap if this standard is not modified so that it applies to a Generator Owner *if and when it executes an Agreement* to evaluate the reliability impact of interconnecting a third party Facility to its existing generation interconnection Facility. The intent of this modified language is to start the compliance clock when the Generator Owner executes an Agreement to perform the reliability assessment required in FAC-002-1. This step is expected to occur if a Generator Owner is compelled by a regulatory body to allow such interconnection. Assuming that a regulatory body would require a Generator Owner to evaluate such an interconnection request, the SDT expects the Generator Owner and the third party to execute some form of an Agreement. The SDT intentionally excluded a specific reference to the form of Agreement (such as a feasibility study) in deference to stakeholder suggestions to avoid comingling of commercial and reliability issues in reliability standards.

The SDT acknowledges that the scenario described in the proposed FAC-001-1 may be rare, but in the past (for instance, FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities, and the SDT thinks it is important to clarify the responsibilities related to such a request in NERC's Reliability Standards. And, while the SDT acknowledges that such regulatory action might also result in the Generator Owner being registered for other functions, such as Transmission Owner, Transmission Planner, and/or Transmission Service Provider, it decided the proposed revision provides appropriate reliability coverage until any additional registration is required and does not impact any Generator Owner that never executes an Agreement as described in the standard.

### ***FAC-003-X and FAC-003-3—Vegetation Management***

The SDT and most stakeholders agree with the Ad Hoc Group recommendation that FAC-003 be applicable to Generator Owners that own a generation interconnection Facility if that Facility contains overhead conductors. The Ad Hoc Group originally excluded such a Facility from this requirement if its length is less than two spans (generally one half mile from the generator property line). The SDT agrees with that intended exclusion in principle; as it discusses in the document titled "[Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface](#)," the SDT recognizes that in many cases, generation Facilities are (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale for exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit.



Thus, the SDT has maintained this exception language but has modified it based on stakeholder input such that it excludes Facilities shorter than one mile which have a clear line of sight from the fenced area of the generating switchyard to the point of interconnection. Specifically, to clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight. 4.3.1 of FAC-003-X now reads:

Generator Owner that owns an overhead transmission line(s) that (1) extends greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) does not have a clear line of sight from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and is operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.

4.3.1 of FAC-003-3 now reads:

Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) do not have a clear line of sight from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and are: Operated at 200kV or higher; or operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

Both references to clear line of sight include a footnote stating: "'Clear line of sight' means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day."

The SDT took into consideration all comments submitted in both formal comment periods, and believes that this exemption now adequately addresses the reliability impact for a majority of the Facilities, while balancing the efforts necessary to support the standard from all entities.

#### ***PRC-004-2.1—Analysis and Mitigation of Transmission and Generation Protection System Misoperations***

After examining all standards it had previously reviewed, the SDT elected to propose a slight change to PRC-004-2.1. While the SDT rejected other opportunities to "drop" the phrase "generator interconnection Facility" into requirements because it is not typically the best way to add clarity, in the case of PRC-004-2, the SDT fears that the phrasing of R2 ("The Generator Owner shall analyze its generator Protection System Misoperations...") could lead to some confusion about whether an interconnection Facility is included. Thus, the SDT proposes adding "and generator interconnection Facility" as redlined in the draft standard. Because there is no change in applicability, and because the

SDT believes that most Generator Owners already interpret the standard in this manner, we consider this to be a minor and not substantive change employed only to add clarity.

**PRC-005-1a—Transmission and Generation Protection System Maintenance and Testing**

In the concurrent 45-day comment and ballot period that ended in November 2011, several commenters pointed out that the wording in R1 and R2 of PRC-005-1a requires the same explicit reference to a generator interconnection Facility that was added in PRC-004-2.1 R2. The SDT agrees and is developing revisions to PRC-005-1a. These will be posted (separate from the recirculation ballot posting) soon.

**Review of Other Standards Considered by the Standard Drafting Team**

To ensure that no reliability gaps were left when the SDT shifted its strategy from the original strategy of the Ad Hoc Group, the SDT reviewed all standards for which the Ad Hoc Group had proposed changes, and again discussed whether making these standards applicable to Generator Owners or Generator Operators would increase reliability with respect to generator requirements at the transmission interface. During the 45-day concurrent comment and ballot period that ended in November 2011, the SDT also received comments from NERC staff encouraging it to review additional standards that NERC staff had proposed to apply to Generator Owners and Generator Operators in [NERC Compliance Process Directive #2011-CAG-001 Regarding Generator Transmission Leads](#) (Directive). Similarly, stakeholder commenters encouraged the SDT to review standards cited in FERC’s Order Denying Compliance Registry Appeals of Cedar Creek Wind Energy and Milford Wind Corridor Phase I (135 FERC ¶ 61,241) (FERC Order).

The SDT reviewed all of these standards and requirements again and continues to find clear and technical reliability-based reasons that support not adding Generator Owner and Generator Operator requirements to the standards. The chart below indicates where else (the Ad Hoc Report, the NERC Directive, or the FERC Order) the standards addressed were discussed. While both the NERC Directive and FERC Orders address specific requirements within these standards, the SDT has found it useful to address each standard as a whole. Often, requirements within a standard, or even from standard to standard, work in concert to ensure that there are no reliability gaps, whereas a review of a requirement in isolation might give the impression that there is gap.

Standard	Ad Hoc Report*	NERC Directive	FERC Order
EOP-003-1	X		
EOP-005-1		X	
FAC-001-0		X	
FAC-003-1 or FAC-003-2	X	X	X
FAC-014-2		X	X
IRO-005-2	X		
PER-001-0	X		

PER-002-0	X	X	
PER-003-1			X
PRC-001-1		X	X
TOP-001-1	X	X	X
TOP-004-2	X	X	X
TOP-006-1		X	
TOP-008-1	X		

\*This chart and accompanying document only address those standards in the Ad Hoc Report for which substantive changes (change in applicability or the addition of a new requirement) were proposed.

The SDT acknowledges that both NERC and FERC have stated that neither the NERC Directive nor the FERC Order is intended to prejudge the work of the SDT. The SDT also acknowledges that the discussion in the FERC Order is related to specific cases in which certain entities will actually be registered as Transmission Owners and Transmission Operators, a process that is distinct from the SDT’s work, which assumes that once this project is complete, Generator Owners and Generator Operators will not be registered for any other functions based on ownership of a sole-use generator interconnection Facility. Still, because these related efforts are ongoing, the SDT thought it would be useful to directly address some of the discussion in the Directive and the Order. The rest of this document provides the SDT’s technical justification for limiting the scope of its work to FAC-001, FAC-003, PRC-004, and PRC-005.

***EOP-003-1—Load Shedding Plans (addressed in the Ad Hoc Report)***

For EOP-003-1, the Ad Hoc Group originally proposed that Generator Operators be added to the requirement that requires Transmission Operators and Balancing Authorities to coordinate automatic load-shedding throughout their areas. The SDT determined that this addition was unnecessary because PRC-001 already includes the requirement that Transmission Operators coordinate their underfrequency load shedding programs with underfrequency isolation of generating units, which implies that Generator Operators need to provide their underfrequency settings to their respective Transmission Operator. Further, Generator Operators typically do not have the technical expertise or access to the data necessary for the high-level coordination that this standard requires.

***EOP-005-1—System Restoration Plans (addressed in the NERC Directive)***

In its Directive, NERC staff states the following by way of rationale for applying EOP-005-1 Requirements R1, R2, R5, R6, and R7 to Generator Operators:

“If GOP has blackstart capability, then EOP-005 applies, GOP restoration plan would require coordination with TOP per the TOP Blackstart Restoration Plan. The GOP would start its blackstart resources to provide necessary real and reactive power to its generating resources per interconnecting TOP directives. In addition, if GOP has blackstart capability the

interconnection TOP will have included this capability in its restoration planning for its area of responsibility. If GOP does not have blackstart capability, GOP restoration plan is dependent upon provision of real and reactive power service from interconnecting TOP, per VAR-001 and VAR-002 requiring the GOP to follow the directives of the interconnecting TOP, compliance with this standard/requirements is not required.”

Blackstart capability of a generating unit is unrelated to owning or operating transmission Facilities or a generation interconnection Facility. During a system restoration event, Generator Operators provide real and reactive power to the BES only at the direction of a Transmission Operator. The Generator Operators are not providing Transmission Operator services through their blackstart Facilities. In addition, many units with blackstart capability are not included in a TOP System Restoration Plan.

In FERC Order 693, paragraph 630, FERC approved EOP-005-1 and found the standard “adequately addresses operating personnel training and system restoration plans to ensure that transmission operators, balancing authorities and reliability coordinators are prepared to restore the Interconnection following a blackout. Accordingly, the Commission approves Reliability Standard EOP-005-1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP-005-1 through the Reliability Standards development process that identifies time frames for training and review of restoration plan requirements.”

FERC also specifically addressed system restoration training concerns and requirements in FERC Order 693 in its review and approval of Reliability Standard EOP-005-1. In that order, FERC stated that personnel outside a control room should be trained in system restoration, but also that this should be included in a system restoration Reliability Standard, as follows:

627. With regard to comments that the Commission’s concerns are being addressed in NERC’s drafting of proposed PER-005-1 Reliability Standard on operator training, we note PER-005-1 only includes Requirements on the control room personnel and not those outside of the control room. System restoration requires the participation of not only control room personnel but also those outside of the control room. These include blackstart unit operators and field switching operators in situations where SCADA capability is unavailable. As such, the Commission believes that inclusion of periodic system restoration drills and training and review of restoration plans in a system restoration Reliability Standard is the most effective way of achieving the desired goal of ensuring that all participants are trained in system restoration and that the restoration plans are up to date to deal with system changes.

Thus, FERC clearly found that the existing standard EOP-005-1 adequately addressed operating personnel training and would ensure the restoration of the BES in the event of a blackstart, and further directed that any modifications be addressed through the Reliability Standard Development Process.

Pursuant to Order 693, NERC initiated Project 2006-03, and empowered the System Restoration and Blackstart Standard Drafting Team (SRBSDT) to modify the related standards. The SRBSDT developed Reliability Standard EOP-005-2, which includes Generator Operator system restoration requirements including training, restoration plans, drills, and testing of blackstart resources. In Order 749, FERC approved EOP-005-2, which included its approval of the implementation plan for EOP-005-2. Again, both FERC and NERC had the opportunity to identify issues with the implementation time of EOP-005-2 and declined to do so.

5. Currently effective Reliability Standard EOP-005-1 requires transmission operators, balancing authorities, and reliability coordinators to have a restoration plan, test the plan, train operating personnel in the restoration plan, and have the ability to restore the Interconnection using the plans following a blackout. In Order No. 693, the Commission directed the ERO to develop, through the Reliability Standard development process, a modification to EOP-005-1 that identifies time frames for training and review of restoration plan requirements to simulate contingencies and prepare operators for anticipated and unforeseen events . . .

Also, in FERC Order 749, both NERC and FERC identified the modifications to EOP-005 as “improvements” to the standard, not changes to close a reliability gap:

10. NERC states that the proposed Reliability Standards “represent significant revision and improvement from the current set of enforceable standards” and address the Commission’s directives in Order No. 693 related to the EOP standards. NERC explains that, among other enhancements, “[t]he proposed revisions now clearly delineate the responsibilities of the Reliability Coordinator and Transmission Operator in the restoration process and restoration planning.” NERC describes the proposed Reliability Standards as providing “specific requirements for what must be in a restoration plan, how and when it needs to be updated and approved, what needs to be provided to operators and what training is necessary for personnel involved in restoration processes.

17. . . . By enhancing the rigor of the restoration planning process, the Reliability Standards represent an improvement from the current Standards and will improve the reliability of the Bulk-Power System. . . .

In summary, the Generator Operator blackstart requirements have been already been appropriately addressed through the Reliability Standards Development Process. EOP-005-2 will become effective in 2013 as approved by both the NERC Board of Trustees and FERC. There is no existing reliability gap related to owning a generation interconnection Facility and Standard EOP-005-1.

***FAC-014-2—Establish and Communicate System Operating Limits (addressed in the NERC Directive and the FERC Order)***

FAC-014-2, R2 states “The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator’s SOL Methodology.”

In its Directive, NERC states, with respect to FAC-014-2: “In the event an RC directs the establishment of an SOL, the SOL must be established in accordance with the RC’s SOL Methodology.”

In paragraphs 68 and 84 of the FERC Order, FERC states that without compliance with FAC-014, R2, the entity in questions could “avoid establishing the system operating limit for its line or be allowed to establish an operating limit for its line that is not consistent with the requirements of the reliability coordinator’s methodology.”

The SDT does not believe that FAC-014-2 R2 should be revised to include Generator Operators. The Generator Owner is required by the FERC-approved versions of FAC-008-1 R1 and FAC-009-1 and pending FAC-008-3 R1, R2, and R6 (which has been filed for approval with FERC) to document the Facility Ratings for a Generator Owner-owned generator interconnection circuit greater than 100kV. The established Facility Rating must respect the most limiting applicable equipment rating in the circuit and must consider operating limitations and ambient conditions. The thermal or ampere rating of this circuit would equal its ampere operating limit and should be conveyed by the Generator Owner to the Generator Operator if they are not the same entity. The operating voltage limits for this circuit are established by the applicable Transmission Owner or Transmission Operator, not the Generator Owner or Generator Operator.

Therefore, we believe adding the Generator Owner to FAC-014-2 R2 would be redundant. What’s more, the SDT is concerned that entities with a limited view of the system should not be setting IROLs or SOLs. We believe this should be the responsibility of entities with a wide-area view, as shown in the standard today; otherwise, we are concerned that reliability may be jeopardized. Commenters – including one from the Transmission Owner segment – have offered this same justification.

***IRO-005-2—Reliability Coordination – Current Day Operations (addressed in the Ad Hoc Report)***

The SDT chose not to adopt the revision to IRO-005-2 proposed by the Ad Hoc Group. This revision would have added a new requirement that would read, “The Generator Operator shall immediately inform the Transmission Operator of the status of the Special Protection System, including any degradation or potential failure to operate as expected for SPS relay or control equipment under its control.” The SDT initially determined that IRO-005-2 did not require modification because of the October 2011 retirement of the standard. In subsequent meetings, the SDT also reached the conclusion that there is no reliability gap as PRC-001-1 R2 already requires the Generator Operator to notify reliability entities of relay or equipment failures. The SDT believes that a Special Protection

System is a form of protection system and therefore any degradation or potential failure to operate as expected would be required to be reported by the Generator Operator to reliability entities (Balancing Authorities, Transmission Operators, and Reliability Coordinators).

***PER Standards (PER-001-0 and PER-002-0 were addressed in the Ad Hoc Report; PER-002-0 was addressed in the NERC Directive; and PER-003-1 was addressed in the FERC Order)***

The Ad Hoc Group had proposed changes to PER-001-0—Operating Personnel Responsibility and Authority and PER-002-0—Operating Personnel Training. For PER-001-0, the Ad Hoc Group proposed adding a new R2 that would read “Each Generator Operator shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Generation Facility and Generation Interconnection Facility, and the responsibility and authority to follow the directives of reliability authorities including the Transmission Operator and Balancing Authority.” To PER-002-0, the Ad Hoc Group proposed adding the Generator Operator to R1 (“Each Transmission Operator, Generator Operator, and Balancing Authority shall be staffed with adequately trained operating personnel”) and adding a new R3 that would read: “Each Generator Operator shall implement an initial and continuing training program for all operating personnel that are responsible for operating the Generator Interconnection Facility that verifies the personnel’s ability and understanding to operate the equipment in a reliable manner.”

In its Directive, NERC does not address PER-001-0, but it states the following with respect to PER-002-0:

“The registered entity will develop an appropriate training program that contains the necessary elements for the GO/GOP operating a transmission facility to understand fully the impacts of the operation on the BPS, such as equipment involved, including protection systems, the coordination aspects with the TO/TOP to which it is connected, and the protocols for and impacts of operating facilities associated with the transmission facility. The objective of this training is to ensure that the GO/GOP is completely aware of its obligations to follow the directives of the appropriate TOP and has personnel with the skills and training to execute these obligations in the best interest of reliability.”

These proposed changes to the PER standards have little to do with responsibilities that relate specifically to a generator interconnection Facility. Issues related to the training of Generator Operators existed separately from the work of Project 2010-07, and the SDT agrees that its scope limits its efforts to standards that are directly related to generator requirements at the transmission interface. The SDT also cites past FERC Orders as proof that this issue is not within the scope of Project 2010-07. In Order 693, FERC directed NERC to “expand the applicability of the personnel training Reliability Standard, PER-002-0, to include (i) generator operators centrally-located at a generation control center with a direct impact on the reliable operation of the Bulk-Power System...” In Order 742, FERC reaffirmed this, stating that it is “not modifying the Order No. 693 directive regarding training for



certain generator operator dispatch personnel, nor are we expanding a generator operator's responsibilities."

Centrally-located generator operators working at a generation control center typically dispatch the output from multiple generating units. As such, they can be called upon to comply with orders from their Balancing Authority that may have a significant impact on the reliable operation of the BES. Their training would be covered by proposed changes to PER-002-0 and Order 742. Generator Operators who deal with interconnection Facilities at individual generating plants, on the other hand, typically do not receive reliability-based orders specific to the interconnection Facilities and are therefore not covered by Order 742. Further, the SDT believes there is no reliability gap as TOP-001-1 R3 already requires Generator Operators to follow the directives of the appropriate Transmission Operators.

These training-related items are clearly important ones for the Commission, but the SDT does not think it is appropriate to fold modifications to these PER standards into the scope of its work unless it is specifically directed to do so. For now, modifications to PER-002-0 based on Order 693 directives are already included in [NERC's Issue Database](#) (P. 52-53) to be addressed by a future project. PER-001-0 is not addressed in the Issues Database, but the [Project 2007-03 drafting team has proposed](#) that the standard be retired.

The FERC Order does not address PER-001-0 or PER-002-0, but it does address PER-003-1. In paragraphs 67 and 81 of the FERC Order, FERC expresses concern that operational control over the transmission line breakers owned by the entities in question are not under the control of NERC certified operators. FERC goes on to say that "Reliability Standard PER-003-001 requires NERC certification of all operators that have responsibility for the real-time operation of the interconnected Bulk Electric System. When switching the tie-line in or out of service, operators must have the appropriate credentials and training to properly perform the switching and coordinate the switching to prevent adverse impacts such as the introduction of faults on the system."

The SDT can find no evidence that the kinds of training requirements for operating the breakers of the generator interconnection Facility cited in the FERC Order exist elsewhere for other entities that operate breakers on lines. For instance, Transmission Owners that are not also Transmission Operators are not required to undergo any sort of training. The SDT does not mean to dismiss this issue altogether, and it may be that training should be expanded to include Generator Owners, Generator Operators, Transmission Owners, end users, and possibly others, but the development of such requirements would have implications far beyond the scope and expertise of this team.

***PRC-001-1—System Protection Coordination (addressed in the NERC Directive and the FERC Order)***

The NERC Directive addresses PRC-001-1 R2, R2.2, and R4. The FERC Order addresses these requirements, along with Requirement R6.



About R2 and R4, NERC's Directive simply states: "PRC-001-R2 requires notification and corrective action for relay or equipment failure. R4 coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities."

In paragraphs 64 and 78 of the FERC Order, FERC expresses concern that "there is a risk of an adverse impact on reliability if the protection relays or protection systems on the [entity's] line are not coordinated with those on the transmission network facilities in its area."

Generator Operators and the scope of protection equipment for generation interconnection Facilities are already appropriately accounted for in this standard in requirement R2 and sub-requirement R2.2. The language used in R2 that applies to the Generator Operator uses the general terms "relay or equipment failures" which would include not only generator relaying, but generator interconnection relaying in the Generator Operator's scope as well. The Generator Operator is required to notify the Transmission Operator and Host Balancing Authority in R2.1 "if a protective relay or equipment failure reduces system reliability." Requirement R2.2 requires the affected Transmission Operator to notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. Thus, applying R2.2 to a Generator Operator would be redundant to R2.1. If a Generator Operator had a relay or equipment failure on its Facility, including its interconnection Facility it would be required to report that to its Transmission Operator under R2.1, and the Transmission Operator is then required to notify its Reliability Coordinator and other affected Transmission Operators and Balancing Authorities under R2.2.

PRC-001-1 R4 states, "Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities." A sole-use generator interconnection Facility does not constitute a major transmission line or major interconnection with neighboring Generator Operators, Transmission Operators, and Balancing Authorities. Thus, R4 should not be revised to include Generator Operators. In general, any coordination that might be required is covered by the fact that the Transmission Operator that is connected to a major transmission lines or interconnection has the requirement to coordinate protection on the interconnection, and there is no reliability gap.

PRC-001-1 R6 states, "Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status." It is clearly the responsibility of the Transmission Operator and/or Balancing Authority to monitor the Special Protection System, as they are the entity with a wide-area view, not the responsibility of a Generator Owner/Generator Operator with a local-area view who happens to have generator interconnection Facilities in the area. The requirement focuses on the Transmission Operator and Balancing Authority monitoring the status of each Special

Protection System *in their area*; there is no “area” for the Generator Operator to monitor. For these reasons, there is no need to make this requirement applicable to Generator Operators.

***TOP-001-1—Reliability Responsibilities and Authority (addressed in the Ad Hoc Report, NERC Directive, and FERC Order)***

Both the NERC Directive and the FERC Order discuss making TOP-001-1 R1 applicable to Generator Operators. About TOP-001-1, the NERC Directive simply states: “TOP-001-1 R1 ensures personnel assigned to operate BES transmission facilities have clear and unambiguous authority to operate those facilities.” With respect to R1, paragraphs 68 and 83 of FERC’s Order focus on ensuring that “system operators have the authority to take actions to maintain Bulk-Power System facilities within operating limits.”

TOP-001-1 R1 states, “Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.” TOP-001-1 R3 appropriately requires the GOP to comply with reliability directives issued by the Transmission Operator “unless such actions would violate safety, equipment, regulatory or statutory requirements.” These requirements effectively give the Transmission Operator the necessary decision-making authority over operation of all generator Facilities up to the point of interconnection. Thus, no changes to TOP-001-1 are necessary.

Additionally, the Ad Hoc Group proposed adding two new requirements to TOP-001-1. The first was proposed as R9 and read: “The Generator Operator shall coordinate the operation of its Generator Interconnection Facility with the Transmission Operator to whom it interconnects in order to preserve Interconnection reliability...” The SDT does not agree that TOP-001-1 needs to apply to Generator Operators in any form. TOP-002-2 R3 (proposed to be covered in the future by TOP-003-2, as outlined in Project 2007-03’s Implementation Plan) already requires the Generator Operator to coordinate its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. These entities are, in turn, required to coordinate with their respective Transmission Operator. Additionally, TOP-002-2 R4 (proposed to be covered in the future by TOP-003-2, as outlined in Project 2007-03’s Implementation Plan) requires each Balancing Authority and Transmission Operator to coordinate with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator. With these requirements, Generator Operators are already required to provide necessary operations information to Transmission Operators. To require the same thing in TOP-001-1 would be redundant.

The second new requirement proposed by the Ad Hoc Group for TOP-001-1 was R10, which was to read: “The Transmission Operator shall have decision-making authority over operation of the Generator Interconnection Operational Interface at all times in order to preserve Interconnection reliability.” As cited above, TOP-002-2 R3 (proposed to be covered in the future by TOP-003-2, as

outlined in Project 2007-03's Implementation Plan) already requires the Generator Operator to coordinate with its interconnecting Transmission Operator. Further, TOP-001-1 R3 (proposed to be covered in the future in the proposed IRO-001-2 R2 and R3) already requires the Generator Operator to comply with reliability directives issued by the Transmission Operator. These requirements effectively give the Transmission Operator decision-making authority over operation of all generator Facilities up to the point of interconnection. To require the same thing in TOP-001-1 would be redundant.

***TOP-004-2—Transmission Operations (addressed in the NERC Directive and the FERC Order)***

Both the NERC Directive and the FERC Order address the application of TOP-004-2 R6 to Generator Operators. In its Directive, NERC simply states: "TOP-004-2 R6 ensures formal policies and procedures are formulated to provide for coordination of activities that may impact reliability." In paragraphs 67 and 82 of the FERC Order, FERC talks about entities ensuring the development of coordination protection to coordinate switching a generator interconnection Facility in and out of service, since different entities have control over different ends of the line. FERC concludes that for the entities in question, TOP-004-2 R6 must apply.

Requirement R6 and its sub-requirements state: "R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: R6.1. Monitoring and controlling voltage levels and real and reactive power flows, R6.2. Switching transmission elements, R6.3. Planned outages of transmission elements, R6.4. Responding to IROL and SOL violations."

TOP-001-1 R3 appropriately requires the Generator Operator to comply with reliability directives issued by the Transmission Operator. These requirements give the Transmission Operator the necessary decision-making authority over operation of all generator Facilities, including interconnection Facilities, up to the point of interconnection. Further, TOP-002-2 R3 requires the Generator Owner to coordinate its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. These entities are, in turn, required to coordinate with their respective Transmission Operators (also in TOP-002-2 R3). Each Balancing Authority and Transmission Operator is also then required to coordinate with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator (in TOP-002-2 R4). The coordination with which NERC and FERC are concerned is already addressed by these other requirements.

The Ad Hoc Group had proposed a new requirement, R7, for TOP-004-2 that would read: "The Generator Operator shall operate its Generator Interconnection Facility within its applicable ratings." The SDT does not agree that a reliability gap exists, because an operator has a fiduciary obligation to

protect a Facility for which it is operationally responsible. FAC-008-1—Facility Ratings Methodology and FAC-009-1—Establish and Communicate Facility Ratings already infer that the reason for establishing a ratings methodology and communicating Facility Ratings to the Reliability Coordinator, Planning Authority, Transmission Planner, and Transmission Operator is “...for use in reliable planning and operation of the Bulk Electric System.” Further, TOP-004-2 is proposed to be retired under the work of the Project 2007-03 drafting team. Its requirements will either be deleted or assigned elsewhere.

***TOP-006-1—Monitoring System Conditions (addressed in the NERC Directive; the SDT believes NERC intended to refer to TOP-006-2)***

Only the NERC Directive addresses TOP-006. It states: “TOP-006-1 R3 ensures technical information is provided to the responsible personnel; R6 ensures correct and accurate data to TOP and BA.” But PRC-001-1 R1 (“Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area”) addresses the necessary Generator Operator requirements with respect to TOP-006-2 R3. The SDT believes that knowledge of the purpose and limitations of protection system schemes applied in its area (required in PRC-001-1 R1) constitutes knowledge of “the appropriate technical information concerning protective relays” (required in TOP-006-1 R3).

TOP-006-2 R6 states “Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.” FAC-001-1 R2.1.6 already requires the Transmission Owner’s facility connection requirements to address “metering and telecommunications.” Any generator Facility that interconnected with a Transmission Owner would have had to meet their Facility connection and system performance requirements for metering and telecommunications. Thus, there is no reliability gap.

***TOP-008-1—Response to Transmission Limit Violations (addressed in the Ad Hoc Report)***

Only the Ad Hoc Report addressed TOP-008-1, and it proposed a new requirement, R5, to TOP-008-1—Response to Transmission Limit Violations that would read “The Generator Operator shall disconnect the Generator Interconnection Facility when safety is jeopardized or the overload or abnormal voltage or reactive condition persists and generating equipment or the Generator Interconnection Facility is endangered. In doing so, the Generator Operator shall notify its Transmission Operator and Balancing Authority impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.” The SDT sees no reliability benefit to adding this requirement. TOP-001-1 R7 (“Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless...”) and its parts give the Generator Operator authority over its Facilities, which would include the generator interconnection Facility. If there is an outage, R7.1 requires the Generator Operator to notify and coordinate with its Transmission Operator, which is required to notify the Reliability Coordinator and other affected

Transmission Operators. And as with TOP-004-2, the Project 2007-03 drafting team has proposed to delete all of TOP-008-1's requirements and retiring the standard.

**Conclusion**

The Project 2010-07 SDT is confident that the changes it has proposed address the reliability gap that exists with respect to the responsibilities of Generator Owners and Generator Operations that own sole-use interconnection Facilities. The changes to FAC-001, FAC-003, and PRC-004 have been supported by stakeholders during comment periods, and there has been no strong support of technical justification provided for bringing other standards into the scope of this project.

# Technical Justification Resource Document

## Project 2010-07 Generator Requirements at the Transmission Interface

### Background

As part of its work on Project 2010-07—Generator Requirements at the Transmission Interface, the standard drafting team (SDT) reviewed 34 reliability standards and 102 requirements to determine what changes are necessary to close a reliability gap with respect to what is commonly known as the generator interconnection Facility. Many of these standards and requirements had been addressed in the [Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface](#) (Ad Hoc Report) and additional standards were reviewed as a result of informal discussions with NERC and FERC staffs.

The SDT's technical justification document has not changed substantively since it was posted in December 2011, but the document below has been updated to reflect the posted changes to FAC-003-3 and FAC-003-X.

The basis for standard modifications recommended by the Ad Hoc Group for Generator Requirements at the Transmission Interface (Ad Hoc Group) was a few fundamental clarifications to the definitions of Generator Owner, Generator Operator, and Transmission, along with the creation of new definitions: one for Generator Interconnection Facility and one for Generator Interconnection Operational Interface. The Ad Hoc Group proposed the addition of these two new definitions to 26 standards encompassing 29 requirements (new and old), along with some modifications to FAC-003 to make it applicable to Generator Owners under certain circumstances.

Since the publication of the Ad Hoc Report, various entities have challenged these modifications and the recommended creation of the new definitions. The SDT has developed a more focused approach than that of the Ad Hoc Group: to propose recommendations whereby sole-use interconnection Facilities (at or above 100 kV) that are owned and operated by generating entities will be included in a small set of standards and requirements previously only applicable to Transmission Owners. The SDT agrees completely with the Ad Hoc Group's conclusion that Generator Owners and Operators of these sole-use generator tie-line Facilities (at voltages equal to or greater than 100 kV) should not be registered as Transmission Owners and Transmission Operators in order to maintain reliability on the Bulk Electric System (BES).

The SDT's justification for this strategy is rooted in the very title of its standards project: "Generator Requirements at the Transmission Interface." That is, the goal and scope of the project has always been to determine the responsibilities of those Generator Owners and Generator Operators that own or operate an interconnection Facility (in some cases labeled a "transmission Facility") between the generator and the interface with the portion of the BES where Transmission Owners and Transmission

Operators take over ownership and operating responsibility. These kinds of Generator Owners and Generator Operators do not own or operate Facilities that are part of the interconnected system; rather, they own and operate sole-use Facilities that are connected to the boundary of the interconnected system and as such have a limited role in providing reliability compared to those that operate in a networked fashion beyond the point of interconnection.

While some argue that these interconnecting portions of a Generator Owner's Facilities could be defined as Transmission and thus require the Generator Owner and Generator Operator for the Facility to be classified and registered as a Transmission Owner and Transmission Operator, the SDT does not believe this is necessary to provide an appropriate level of reliability for the BES. Just as important, such classification and registration could actually cause a reduction in reliability. Generator Owners and Generator Operators do not need, and in some cases may be prohibited from having, a wide-area view and responsibility for the integrated transmission system. Requiring Generator Owners and Generator Operators to have such responsibilities would require significant training, require substantially more data and modeling responsibilities, and detract from the entities' primary functions: to own and operate their generation equipment – including any Facilities owned and operated at voltages of 100 kV or greater that connect to the interconnected system – in a reliable manner.

Additionally, the SDT believes that the industry is much more aware today of the need to include *all* elements (owned and operated at 100 kV or higher) of a generator Facility in the procedures and compliance program of the registered entity that owns or has operational responsibility of those elements. Industry awareness was raised substantially at the time the [October 17, 2010 Facility Ratings Recommendation to Industry](#) was issued (which included Generator Owners and specifically addressed interconnection Facilities in [the Q&A document](#) with the statement that the alert applied to generator interconnection tie lines that are radial only and do not serve load “if the generator is considered part of the bulk electric system”). While this applies to a specific NERC Recommendation, the SDT considers this compelling evidence that the paradigm for thinking about generator interconnection Facilities is shifting.

All of this has led the SDT to its current conclusions to modify FAC-001, FAC-003, and PRC-004 and later, PRC-005. The SDT does not believe any further modifications to standards are necessary to maintain an appropriate level of reliability based on the revised assumption that while generator Facilities (at 100 kV and above) will be considered by some to be transmission, Generator Owners and Generator Operators should not be registered as Transmission Owners and Transmission Operators simply as a result of the ownership and operation of such Facilities. Because the majority of commenters support the SDT's current recommendation to not adopt new terms, the SDT has elected to focus on its standard changes and not, at this time, propose revisions to existing, or creation of new, glossary terms.



Below, the SDT discusses the changes it has proposed for FAC-001, FAC-003, and PRC-004 and the changes it plans to propose for PRC-005 and then provides justification for not modifying any of the additional standards and requirements it has reviewed.

## **Review of SDT's Proposed Standard Changes**

### ***FAC-001-1—Facility Connection Requirements***

While some stakeholders have questioned the modifications in the proposed FAC-001-1, the SDT remains convinced that there is the potential for a reliability gap if this standard is not modified so that it applies to a Generator Owner *if and when it executes an Agreement* to evaluate the reliability impact of interconnecting a third party Facility to its existing generation interconnection Facility. The intent of this modified language is to start the compliance clock when the Generator Owner executes an Agreement to perform the reliability assessment required in FAC-002-1. This step is expected to occur if a Generator Owner is compelled by a regulatory body to allow such interconnection. Assuming that a regulatory body would require a Generator Owner to evaluate such an interconnection request, the SDT expects the Generator Owner and the third party to execute some form of an Agreement. The SDT intentionally excluded a specific reference to the form of Agreement (such as a feasibility study) in deference to stakeholder suggestions to avoid comingling of commercial and reliability issues in reliability standards.

The SDT acknowledges that the scenario described in the proposed FAC-001-1 may be rare, but in the past (for instance, FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities, and the SDT thinks it is important to clarify the responsibilities related to such a request in NERC's Reliability Standards. And, while the SDT acknowledges that such regulatory action might also result in the Generator Owner being registered for other functions, such as Transmission Owner, Transmission Planner, and/or Transmission Service Provider, it decided the proposed revision provides appropriate reliability coverage until any additional registration is required and does not impact any Generator Owner that never executes an Agreement as described in the standard.

### ***FAC-003-X and FAC-003-3—Vegetation Management***

The SDT and most stakeholders agree with the Ad Hoc Group recommendation that FAC-003 be applicable to Generator Owners that own a generation interconnection Facility if that Facility contains overhead conductors. The Ad Hoc Group originally excluded such a Facility from this requirement if its length is less than two spans (generally one half mile from the generator property line). The SDT agrees with that intended exclusion in principle; as it discusses in the document titled "[Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface](#)," the SDT recognizes that in many cases, generation Facilities are (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale for exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit.



Thus, the SDT has maintained this exception language but has modified it based on stakeholder input such that it excludes Facilities shorter than one mile which have a clear line of sight from the fenced area of the generating switchyard to the point of interconnection. Specifically, to clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight. 4.3.1 of FAC-003-X now reads:

Generator Owner that owns an overhead transmission line(s) that (1) extends greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) does not have a clear line of sight from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and is operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.

4.3.1 of FAC-003-3 now reads:

Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) do not have a clear line of sight from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and are: Operated at 200kV or higher; or operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

Both references to clear line of sight include a footnote stating: "'Clear line of sight' means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day."  
~~sections 4.3.1 of both versions of FAC-003 (which address applicable generation Facilities) now state: "Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are..."~~

The SDT took into consideration all comments submitted in both formal comment periods, and believes that this exemption now adequately addresses the reliability impact for a majority of the Facilities, while balancing the efforts necessary to support the standard from all entities.

### ***PRC-004-2.1—Analysis and Mitigation of Transmission and Generation Protection System Misoperations***

After examining all standards it had previously reviewed, the SDT elected to propose a slight change to PRC-004-2.1. While the SDT rejected other opportunities to “drop” the phrase “generator interconnection Facility” into requirements because it is not typically the best way to add clarity, in the case of PRC-004-2, the SDT fears that the phrasing of R2 (“The Generator Owner shall analyze its

generator Protection System Misoperations...”) could lead to some confusion about whether an interconnection Facility is included. Thus, the SDT proposes adding “and generator interconnection Facility” as redlined in the draft standard. Because there is no change in applicability, and because the SDT believes that most Generator Owners already interpret the standard in this manner, we consider this to be a minor and not substantive change employed only to add clarity.

**PRC-005-1a—Transmission and Generation Protection System Maintenance and Testing**

In the concurrent 45-day comment and ballot period that ended in November 2011, several commenters pointed out that the wording in R1 and R2 of PRC-005-1a requires the same explicit reference to a generator interconnection Facility that was added in PRC-004-2.1 R2. The SDT agrees and is developing revisions to PRC-005-1a. These will be posted (separate from the recirculation ballot posting) soon.

**Review of Other Standards Considered by the Standard Drafting Team**

To ensure that no reliability gaps were left when the SDT shifted its strategy from the original strategy of the Ad Hoc Group, the SDT reviewed all standards for which the Ad Hoc Group had proposed changes, and again discussed whether making these standards applicable to Generator Owners or Generator Operators would increase reliability with respect to generator requirements at the transmission interface. During the 45-day concurrent comment and ballot period that ended in November 2011, the SDT also received comments from NERC staff encouraging it to review additional standards that NERC staff had proposed to apply to Generator Owners and Generator Operators in [NERC Compliance Process Directive #2011-CAG-001 Regarding Generator Transmission Leads](#) (Directive). Similarly, stakeholder commenters encouraged the SDT to review standards cited in FERC’s Order Denying Compliance Registry Appeals of Cedar Creek Wind Energy and Milford Wind Corridor Phase I (135 FERC ¶ 61,241) (FERC Order).

The SDT reviewed all of these standards and requirements again and continues to find clear and technical reliability-based reasons that support not adding Generator Owner and Generator Operator requirements to the standards. The chart below indicates where else (the Ad Hoc Report, the NERC Directive, or the FERC Order) the standards addressed were discussed. While both the NERC Directive and FERC Orders address specific requirements within these standards, the SDT has found it useful to address each standard as a whole. Often, requirements within a standard, or even from standard to standard, work in concert to ensure that there are no reliability gaps, whereas a review of a requirement in isolation might give the impression that there is gap.

Standard	Ad Hoc Report*	NERC Directive	FERC Order
EOP-003-1	X		
EOP-005-1		X	
FAC-001-0		X	
FAC-003-1 or FAC-003-2	X	X	X

FAC-014-2		X	X
IRO-005-2	X		
PER-001-0	X		
PER-002-0	X	X	
PER-003-1			X
PRC-001-1		X	X
TOP-001-1	X	X	X
TOP-004-2	X	X	X
TOP-006-1		X	
TOP-008-1	X		

\*This chart and accompanying document only address those standards in the Ad Hoc Report for which substantive changes (change in applicability or the addition of a new requirement) were proposed.

The SDT acknowledges that both NERC and FERC have stated that neither the NERC Directive nor the FERC Order is intended to prejudge the work of the SDT. The SDT also acknowledges that the discussion in the FERC Order is related to specific cases in which certain entities will actually be registered as Transmission Owners and Transmission Operators, a process that is distinct from the SDT’s work, which assumes that once this project is complete, Generator Owners and Generator Operators will not be registered for any other functions based on ownership of a sole-use generator interconnection Facility. Still, because these related efforts are ongoing, the SDT thought it would be useful to directly address some of the discussion in the Directive and the Order. The rest of this document provides the SDT’s technical justification for limiting the scope of its work to FAC-001, FAC-003, PRC-004, and PRC-005.

***EOP-003-1—Load Shedding Plans (addressed in the Ad Hoc Report)***

For EOP-003-1, the Ad Hoc Group originally proposed that Generator Operators be added to the requirement that requires Transmission Operators and Balancing Authorities to coordinate automatic load-shedding throughout their areas. The SDT determined that this addition was unnecessary because PRC-001 already includes the requirement that Transmission Operators coordinate their underfrequency load shedding programs with underfrequency isolation of generating units, which implies that Generator Operators need to provide their underfrequency settings to their respective Transmission Operator. Further, Generator Operators typically do not have the technical expertise or access to the data necessary for the high-level coordination that this standard requires.

***EOP-005-1—System Restoration Plans (addressed in the NERC Directive)***

In its Directive, NERC staff states the following by way of rationale for applying EOP-005-1 Requirements R1, R2, R5, R6, and R7 to Generator Operators:

“If GOP has blackstart capability, then EOP-005 applies, GOP restoration plan would require coordination with TOP per the TOP Blackstart Restoration Plan. The GOP would start its blackstart resources to provide necessary real and reactive power to its generating resources per interconnecting TOP directives. In addition, if GOP has blackstart capability the interconnection TOP will have included this capability in its restoration planning for its area of responsibility. If GOP does not have blackstart capability, GOP restoration plan is dependent upon provision of real and reactive power service from interconnecting TOP, per VAR-001 and VAR-002 requiring the GOP to follow the directives of the interconnecting TOP, compliance with this standard/requirements is not required.”

Blackstart capability of a generating unit is unrelated to owning or operating transmission Facilities or a generation interconnection Facility. During a system restoration event, Generator Operators provide real and reactive power to the BES only at the direction of a Transmission Operator. The Generator Operators are not providing Transmission Operator services through their blackstart Facilities. In addition, many units with blackstart capability are not included in a TOP System Restoration Plan.

In FERC Order 693, paragraph 630, FERC approved EOP-005-1 and found the standard “adequately addresses operating personnel training and system restoration plans to ensure that transmission operators, balancing authorities and reliability coordinators are prepared to restore the Interconnection following a blackout. Accordingly, the Commission approves Reliability Standard EOP-005-1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP-005-1 through the Reliability Standards development process that identifies time frames for training and review of restoration plan requirements.”

FERC also specifically addressed system restoration training concerns and requirements in FERC Order 693 in its review and approval of Reliability Standard EOP-005-1. In that order, FERC stated that personnel outside a control room should be trained in system restoration, but also that this should be included in a system restoration Reliability Standard, as follows:

627. With regard to comments that the Commission’s concerns are being addressed in NERC’s drafting of proposed PER-005-1 Reliability Standard on operator training, we note PER-005-1 only includes Requirements on the control room personnel and not those outside of the control room. System restoration requires the participation of not only control room personnel but also those outside of the control room. These include blackstart unit operators and field switching operators in situations where SCADA capability is unavailable. As such, the Commission believes that inclusion of periodic system restoration drills and training and review of restoration plans in a system restoration Reliability Standard is the most effective way of achieving the desired goal of ensuring that all participants are trained in system restoration and that the restoration plans are up to date to deal with system changes.

Thus, FERC clearly found that the existing standard EOP-005-1 adequately addressed operating personnel training and would ensure the restoration of the BES in the event of a blackstart, and further directed that any modifications be addressed through the Reliability Standard Development Process.

Pursuant to Order 693, NERC initiated Project 2006-03, and empowered the System Restoration and Blackstart Standard Drafting Team (SRBSDT) to modify the related standards. The SRBSDT developed Reliability Standard EOP-005-2, which includes Generator Operator system restoration requirements including training, restoration plans, drills, and testing of blackstart resources. In Order 749, FERC approved EOP-005-2, which included its approval of the implementation plan for EOP-005-2. Again, both FERC and NERC had the opportunity to identify issues with the implementation time of EOP-005-2 and declined to do so.

5. Currently effective Reliability Standard EOP-005-1 requires transmission operators, balancing authorities, and reliability coordinators to have a restoration plan, test the plan, train operating personnel in the restoration plan, and have the ability to restore the Interconnection using the plans following a blackout. In Order No. 693, the Commission directed the ERO to develop, through the Reliability Standard development process, a modification to EOP-005-1 that identifies time frames for training and review of restoration plan requirements to simulate contingencies and prepare operators for anticipated and unforeseen events . . .

Also, in FERC Order 749, both NERC and FERC identified the modifications to EOP-005 as “improvements” to the standard, not changes to close a reliability gap:

10. NERC states that the proposed Reliability Standards “represent significant revision and improvement from the current set of enforceable standards” and address the Commission’s directives in Order No. 693 related to the EOP standards. NERC explains that, among other enhancements, “[t]he proposed revisions now clearly delineate the responsibilities of the Reliability Coordinator and Transmission Operator in the restoration process and restoration planning.” NERC describes the proposed Reliability Standards as providing “specific requirements for what must be in a restoration plan, how and when it needs to be updated and approved, what needs to be provided to operators and what training is necessary for personnel involved in restoration processes.

17. . . . By enhancing the rigor of the restoration planning process, the Reliability Standards represent an improvement from the current Standards and will improve the reliability of the Bulk-Power System. . . .

In summary, the Generator Operator blackstart requirements have been already been appropriately addressed through the Reliability Standards Development Process. EOP-005-2 will become effective in

2013 as approved by both the NERC Board of Trustees and FERC. There is no existing reliability gap related to owning a generation interconnection Facility and Standard EOP-005-1.

***FAC-014-2—Establish and Communicate System Operating Limits (addressed in the NERC Directive and the FERC Order)***

FAC-014-2, R2 states “The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator’s SOL Methodology.”

In its Directive, NERC states, with respect to FAC-014-2: “In the event an RC directs the establishment of an SOL, the SOL must be established in accordance with the RC’s SOL Methodology.”

In paragraphs 68 and 84 of the FERC Order, FERC states that without compliance with FAC-014, R2, the entity in questions could “avoid establishing the system operating limit for its line or be allowed to establish an operating limit for its line that is not consistent with the requirements of the reliability coordinator’s methodology.”

The SDT does not believe that FAC-014-2 R2 should be revised to include Generator Operators. The Generator Owner is required by the FERC-approved versions of FAC-008-1 R1 and FAC-009-1 and pending FAC-008-3 R1, R2, and R6 (which has been filed for approval with FERC) to document the Facility Ratings for a Generator Owner-owned generator interconnection circuit greater than 100kV. The established Facility Rating must respect the most limiting applicable equipment rating in the circuit and must consider operating limitations and ambient conditions. The thermal or ampere rating of this circuit would equal its ampere operating limit and should be conveyed by the Generator Owner to the Generator Operator if they are not the same entity. The operating voltage limits for this circuit are established by the applicable Transmission Owner or Transmission Operator, not the Generator Owner or Generator Operator.

Therefore, we believe adding the Generator Owner to FAC-014-2 R2 would be redundant. What’s more, the SDT is concerned that entities with a limited view of the system should not be setting IROs or SOLs. We believe this should be the responsibility of entities with a wide-area view, as shown in the standard today; otherwise, we are concerned that reliability may be jeopardized. Commenters – including one from the Transmission Owner segment – have offered this same justification.

***IRO-005-2—Reliability Coordination – Current Day Operations (addressed in the Ad Hoc Report)***

The SDT chose not to adopt the revision to IRO-005-2 proposed by the Ad Hoc Group. This revision would have added a new requirement that would read, “The Generator Operator shall immediately inform the Transmission Operator of the status of the Special Protection System, including any degradation or potential failure to operate as expected for SPS relay or control equipment under its control.” The SDT initially determined that IRO-005-2 did not require modification because of the

October 2011 retirement of the standard. In subsequent meetings, the SDT also reached the conclusion that there is no reliability gap as PRC-001-1 R2 already requires the Generator Operator to notify reliability entities of relay or equipment failures. The SDT believes that a Special Protection System is a form of protection system and therefore any degradation or potential failure to operate as expected would be required to be reported by the Generator Operator to reliability entities (Balancing Authorities, Transmission Operators, and Reliability Coordinators).

***PER Standards (PER-001-0 and PER-002-0 were addressed in the Ad Hoc Report; PER-002-0 was addressed in the NERC Directive; and PER-003-1 was addressed in the FERC Order)***

The Ad Hoc Group had proposed changes to PER-001-0—Operating Personnel Responsibility and Authority and PER-002-0—Operating Personnel Training. For PER-001-0, the Ad Hoc Group proposed adding a new R2 that would read “Each Generator Operator shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Generation Facility and Generation Interconnection Facility, and the responsibility and authority to follow the directives of reliability authorities including the Transmission Operator and Balancing Authority.” To PER-002-0, the Ad Hoc Group proposed adding the Generator Operator to R1 (“Each Transmission Operator, Generator Operator, and Balancing Authority shall be staffed with adequately trained operating personnel”) and adding a new R3 that would read: “Each Generator Operator shall implement an initial and continuing training program for all operating personnel that are responsible for operating the Generator Interconnection Facility that verifies the personnel’s ability and understanding to operate the equipment in a reliable manner.”

In its Directive, NERC does not address PER-001-0, but it states the following with respect to PER-002-0:

“The registered entity will develop an appropriate training program that contains the necessary elements for the GO/GOP operating a transmission facility to understand fully the impacts of the operation on the BPS, such as equipment involved, including protection systems, the coordination aspects with the TO/TOP to which it is connected, and the protocols for and impacts of operating facilities associated with the transmission facility. The objective of this training is to ensure that the GO/GOP is completely aware of its obligations to follow the directives of the appropriate TOP and has personnel with the skills and training to execute these obligations in the best interest of reliability.”

These proposed changes to the PER standards have little to do with responsibilities that relate specifically to a generator interconnection Facility. Issues related to the training of Generator Operators existed separately from the work of Project 2010-07, and the SDT agrees that its scope limits its efforts to standards that are directly related to generator requirements at the transmission interface. The SDT also cites past FERC Orders as proof that this issue is not within the scope of Project 2010-07. In Order 693, FERC directed NERC to "expand the applicability of the personnel training Reliability Standard, PER-002-0, to include (i) generator operators centrally-located at a generation



control center with a direct impact on the reliable operation of the Bulk-Power System..." In Order 742, FERC reaffirmed this, stating that it is "not modifying the Order No. 693 directive regarding training for certain generator operator dispatch personnel, nor are we expanding a generator operator's responsibilities."

Centrally-located generator operators working at a generation control center typically dispatch the output from multiple generating units. As such, they can be called upon to comply with orders from their Balancing Authority that may have a significant impact on the reliable operation of the BES. Their training would be covered by proposed changes to PER-002-0 and Order 742. Generator Operators who deal with interconnection Facilities at individual generating plants, on the other hand, typically do not receive reliability-based orders specific to the interconnection Facilities and are therefore not covered by Order 742. Further, the SDT believes there is no reliability gap as TOP-001-1 R3 already requires Generator Operators to follow the directives of the appropriate Transmission Operators.

These training-related items are clearly important ones for the Commission, but the SDT does not think it is appropriate to fold modifications to these PER standards into the scope of its work unless it is specifically directed to do so. For now, modifications to PER-002-0 based on Order 693 directives are already included in [NERC's Issue Database](#) (P. 52-53) to be addressed by a future project. PER-001-0 is not addressed in the Issues Database, but the [Project 2007-03 drafting team has proposed](#) that the standard be retired.

The FERC Order does not address PER-001-0 or PER-002-0, but it does address PER-003-1. In paragraphs 67 and 81 of the FERC Order, FERC expresses concern that operational control over the transmission line breakers owned by the entities in question are not under the control of NERC certified operators. FERC goes on to say that "Reliability Standard PER-003-001 requires NERC certification of all operators that have responsibility for the real-time operation of the interconnected Bulk Electric System. When switching the tie-line in or out of service, operators must have the appropriate credentials and training to properly perform the switching and coordinate the switching to prevent adverse impacts such as the introduction of faults on the system."

The SDT can find no evidence that the kinds of training requirements for operating the breakers of the generator interconnection Facility cited in the FERC Order exist elsewhere for other entities that operate breakers on lines. For instance, Transmission Owners that are not also Transmission Operators are not required to undergo any sort of training. The SDT does not mean to dismiss this issue altogether, and it may be that training should be expanded to include Generator Owners, Generator Operators, Transmission Owners, end users, and possibly others, but the development of such requirements would have implications far beyond the scope and expertise of this team.

***PRC-001-1—System Protection Coordination (addressed in the NERC Directive and the FERC Order)***



The NERC Directive addresses PRC-001-1 R2, R2.2, and R4. The FERC Order addresses these requirements, along with Requirement R6.

About R2 and R4, NERC's Directive simply states: "PRC-001-R2 requires notification and corrective action for relay or equipment failure. R4 coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities."

In paragraphs 64 and 78 of the FERC Order, FERC expresses concern that "there is a risk of an adverse impact on reliability if the protection relays or protection systems on the [entity's] line are not coordinated with those on the transmission network facilities in its area."

Generator Operators and the scope of protection equipment for generation interconnection Facilities are already appropriately accounted for in this standard in requirement R2 and sub-requirement R2.2. The language used in R2 that applies to the Generator Operator uses the general terms "relay or equipment failures" which would include not only generator relaying, but generator interconnection relaying in the Generator Operator's scope as well. The Generator Operator is required to notify the Transmission Operator and Host Balancing Authority in R2.1 "if a protective relay or equipment failure reduces system reliability." Requirement R2.2 requires the affected Transmission Operator to notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. Thus, applying R2.2 to a Generator Operator would be redundant to R2.1. If a Generator Operator had a relay or equipment failure on its Facility, including its interconnection Facility it would be required to report that to its Transmission Operator under R2.1, and the Transmission Operator is then required to notify its Reliability Coordinator and other affected Transmission Operators and Balancing Authorities under R2.2.

PRC-001-1 R4 states, "Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities." A sole-use generator interconnection Facility does not constitute a major transmission line or major interconnection with neighboring Generator Operators, Transmission Operators, and Balancing Authorities. Thus, R4 should not be revised to include Generator Operators. In general, any coordination that might be required is covered by the fact that the Transmission Operator that is connected to a major transmission lines or interconnection has the requirement to coordinate protection on the interconnection, and there is no reliability gap.

PRC-001-1 R6 states, "Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status." It is clearly the responsibility of the Transmission Operator and/or Balancing Authority to monitor the Special Protection System, as they are the entity with a wide-area view, not the responsibility of a Generator Owner/Generator Operator with a local-

area view who happens to have generator interconnection Facilities in the area. The requirement focuses on the Transmission Operator and Balancing Authority monitoring the status of each Special Protection System *in their area*; there is no “area” for the Generator Operator to monitor. For these reasons, there is no need to make this requirement applicable to Generator Operators.

***TOP-001-1—Reliability Responsibilities and Authority (addressed in the Ad Hoc Report, NERC Directive, and FERC Order)***

Both the NERC Directive and the FERC Order discuss making TOP-001-1 R1 applicable to Generator Operators. About TOP-001-1, the NERC Directive simply states: “TOP-001-1 R1 ensures personnel assigned to operate BES transmission facilities have clear and unambiguous authority to operate those facilities.” With respect to R1, paragraphs 68 and 83 of FERC’s Order focus on ensuring that “system operators have the authority to take actions to maintain Bulk-Power System facilities within operating limits.”

TOP-001-1 R1 states, “Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.” TOP-001-1 R3 appropriately requires the GOP to comply with reliability directives issued by the Transmission Operator “unless such actions would violate safety, equipment, regulatory or statutory requirements.” These requirements effectively give the Transmission Operator the necessary decision-making authority over operation of all generator Facilities up to the point of interconnection. Thus, no changes to TOP-001-1 are necessary.

Additionally, the Ad Hoc Group proposed adding two new requirements to TOP-001-1. The first was proposed as R9 and read: “The Generator Operator shall coordinate the operation of its Generator Interconnection Facility with the Transmission Operator to whom it interconnects in order to preserve Interconnection reliability...” The SDT does not agree that TOP-001-1 needs to apply to Generator Operators in any form. TOP-002-2 R3 (proposed to be covered in the future by TOP-003-2, as outlined in Project 2007-03’s Implementation Plan) already requires the Generator Operator to coordinate its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. These entities are, in turn, required to coordinate with their respective Transmission Operator. Additionally, TOP-002-2 R4 (proposed to be covered in the future by TOP-003-2, as outlined in Project 2007-03’s Implementation Plan) requires each Balancing Authority and Transmission Operator to coordinate with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator. With these requirements, Generator Operators are already required to provide necessary operations information to Transmission Operators. To require the same thing in TOP-001-1 would be redundant.

The second new requirement proposed by the Ad Hoc Group for TOP-001-1 was R10, which was to read: “The Transmission Operator shall have decision-making authority over operation of the

Generator Interconnection Operational Interface at all times in order to preserve Interconnection reliability.” As cited above, TOP-002-2 R3 (proposed to be covered in the future by TOP-003-2, as outlined in Project 2007-03’s Implementation Plan) already requires the Generator Operator to coordinate with its interconnecting Transmission Operator. Further, TOP-001-1 R3 (proposed to be covered in the future in the proposed IRO-001-2 R2 and R3) already requires the Generator Operator to comply with reliability directives issued by the Transmission Operator. These requirements effectively give the Transmission Operator decision-making authority over operation of all generator Facilities up to the point of interconnection. To require the same thing in TOP-001-1 would be redundant.

***TOP-004-2—Transmission Operations (addressed in the NERC Directive and the FERC Order)***

Both the NERC Directive and the FERC Order address the application of TOP-004-2 R6 to Generator Operators. In its Directive, NERC simply states: “TOP-004-2 R6 ensures formal policies and procedures are formulated to provide for coordination of activities that may impact reliability.” In paragraphs 67 and 82 of the FERC Order, FERC talks about entities ensuring the development of coordination protection to coordinate switching a generator interconnection Facility in and out of service, since different entities have control over different ends of the line. FERC concludes that for the entities in question, TOP-004-2 R6 must apply.

Requirement R6 and its sub-requirements state: “R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: R6.1. Monitoring and controlling voltage levels and real and reactive power flows, R6.2. Switching transmission elements, R6.3. Planned outages of transmission elements, R6.4. Responding to IROL and SOL violations.”

TOP-001-1 R3 appropriately requires the Generator Operator to comply with reliability directives issued by the Transmission Operator. These requirements give the Transmission Operator the necessary decision-making authority over operation of all generator Facilities, including interconnection Facilities, up to the point of interconnection. Further, TOP-002-2 R3 requires the Generator Owner to coordinate its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. These entities are, in turn, required to coordinate with their respective Transmission Operators (also in TOP-002-2 R3). Each Balancing Authority and Transmission Operator is also then required to coordinate with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator (in TOP-002-2 R4). The coordination with which NERC and FERC are concerned is already addressed by these other requirements.

The Ad Hoc Group had proposed a new requirement, R7, for TOP-004-2 that would read: “The Generator Operator shall operate its Generator Interconnection Facility within its applicable ratings.” The SDT does not agree that a reliability gap exists, because an operator has a fiduciary obligation to protect a Facility for which it is operationally responsible. FAC-008-1—Facility Ratings Methodology and FAC-009-1—Establish and Communicate Facility Ratings already infer that the reason for establishing a ratings methodology and communicating Facility Ratings to the Reliability Coordinator, Planning Authority, Transmission Planner, and Transmission Operator is “...for use in reliable planning and operation of the Bulk Electric System.” Further, TOP-004-2 is proposed to be retired under the work of the Project 2007-03 drafting team. Its requirements will either be deleted or assigned elsewhere.

***TOP-006-1—Monitoring System Conditions (addressed in the NERC Directive; the SDT believes NERC intended to refer to TOP-006-2)***

Only the NERC Directive addresses TOP-006. It states: “TOP-006-1 R3 ensures technical information is provided to the responsible personnel; R6 ensures correct and accurate data to TOP and BA.” But PRC-001-1 R1 (“Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area”) addresses the necessary Generator Operator requirements with respect to TOP-006-2 R3. The SDT believes that knowledge of the purpose and limitations of protection system schemes applied in its area (required in PRC-001-1 R1) constitutes knowledge of “the appropriate technical information concerning protective relays” (required in TOP-006-1 R3).

TOP-006-2 R6 states “Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.” FAC-001-1 R2.1.6 already requires the Transmission Owner’s facility connection requirements to address “metering and telecommunications.” Any generator Facility that interconnected with a Transmission Owner would have had to meet their Facility connection and system performance requirements for metering and telecommunications. Thus, there is no reliability gap.

***TOP-008-1—Response to Transmission Limit Violations (addressed in the Ad Hoc Report)***

Only the Ad Hoc Report addressed TOP-008-1, and it proposed a new requirement, R5, to TOP-008-1—Response to Transmission Limit Violations that would read “The Generator Operator shall disconnect the Generator Interconnection Facility when safety is jeopardized or the overload or abnormal voltage or reactive condition persists and generating equipment or the Generator Interconnection Facility is endangered. In doing so, the Generator Operator shall notify its Transmission Operator and Balancing Authority impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.” The SDT sees no reliability benefit to adding this requirement. TOP-001-1 R7 (“Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless...”) and its parts give the

Generator Operator authority over its Facilities, which would include the generator interconnection Facility. If there is an outage, R7.1 requires the Generator Operator to notify and coordinate with its Transmission Operator, which is required to notify the Reliability Coordinator and other affected Transmission Operators. And as with TOP-004-2, the Project 2007-03 drafting team has proposed to delete all of TOP-008-1's requirements and retiring the standard.

**Conclusion**

The Project 2010-07 SDT is confident that the changes it has proposed address the reliability gap that exists with respect to the responsibilities of Generator Owners and Generator Operations that own sole-use interconnection Facilities. The changes to FAC-001, FAC-003, and PRC-004 have been supported by stakeholders during comment periods, and there has been no strong support of technical justification provided for bringing other standards into the scope of this project.

# Consideration of Comments

## Generator Requirements at the Transmission Interface Project 2010-07

On January 20, 2012, Exelon submitted a [Level One Appeal of the standard process for FAC-003-3 and FAC-003-X](#) to NERC's Vice President of Standards and Training that stated the following: "Exelon believes that the NERC Standards Process Manual was not followed, and that based on the substantive changes made to both Standards following the Initial Ballot, NERC should have set the Standards for vote using a Successive Ballot rather than a Recirculation Ballot."

NERC's Vice President of Standards and Training submitted [a timely response](#) to the appeal that found that "Exelon...made its case that the [Standard Processes Manual] was not adhered to and that a change impacting applicability was made between the last successive and recirculation ballot." Accordingly, the Vice President of Standards and Training referred the issue to the Standards Committee for handling, suggesting the following options:

1. Re-post the standard for a successive ballot and recirculation ballot. Essentially set the clock back and correctly replay the last steps of the process.
2. Ask the SDT to remove the clarification language from the final standard and go directly to recirculation ballot.
3. Ask the SDT to redesign the challenged portion of the proposed standard.

He recommended that the Standards Committee pursue option 2. In a Standards Committee Executive Committee (SCEC) conference call on February 23, 2012, the SCEC directed NERC staff to void the FAC-003-3 and FAC-003-X recirculation ballot results of December 2011 and "remand the work to the drafting team with direction to take into account the issues raised in the Exelon appeal submitted in response to the recirculation ballot previously conducted and either: modify the language added following the initial ballot and then re-post the standard for a successive ballot, or remove the language added following the initial ballot and go directly to recirculation ballot."

The Project 2010-07 SDT considered Exelon's appeal in the context of other stakeholder comments submitted in the first successive ballot between October 5 and November 18, 2011. The SDT continues to believe that a reference to line of sight is clarifying.

With this line of sight reference, the SDT simply seeks to clarify the exception language based on the intent that has been agreed upon by the stakeholder body. In its [Consideration of Comments report](#) from the last formal comment period, which ended on July 17, 2011, the SDT explained "We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting

point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor.” With the addition of an explicit line of sight reference here, the SDT believes it has clarified its original intent and appropriately considered all comments submitted.

The SDT has modified 4.3.1 to include a reference to line of sight. 4.3.1 of FAC-003-X now reads:

Generator Owner that owns an overhead transmission line(s) that (1) extends greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner’s Facility or (2) does not have a clear line of sight from the generating station switchyard fence to the point of interconnection with a Transmission Owner’s Facility and is operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.

4.3.1 of FAC-003-3 now reads:

Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner’s Facility or (2) do not have a clear line of sight from the generating station switchyard fence to the point of interconnection with a Transmission Owner’s Facility and are: Operated at 200kV or higher; or operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

Both references to clear line of sight include a footnote stating: “‘Clear line of sight’ means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.”

Additionally, “Regional Entity” has been removed from the applicability section of FAC-003-X because it is not a recognized Functional Entity.

The FAC-003-3 and FAC-003-X recirculation ballot results of December 2011 have been voided, and both standards are being posted for a 30-day concurrent comment period and successive ballot to allow stakeholders the opportunity to comment on these changes.

Members of the ballot pool should note that for this ballot, the SDT will be balloting **both** FAC-003-3 and FAC-003-X, but stakeholders should **not** vote as though they are choosing one or the other. The SDT plans to present FAC-003-3 alone to NERC’s Board of Trustees, but it wants to have FAC-003-X ready to submit to the Board if, for some reason, neither FAC-003-2 nor FAC-003-3 are approved by FERC. Members of the ballot body should vote on the merits of each version of FAC-003 individually. **In**



**other words, stakeholders who support adding GOs to the applicability of FAC-003 should vote in the affirmative for both FAC-003-3 and FAC-003-X.**

The Exelon appeal and NERC response are posted on the [2010-07 project page](#).

Status of other standards that are part of Project 2010-07:

- FAC-001-1 and PRC-004-2.1a were adopted by NERC's Board of Trustees on February 9, 2012
- PRC-005-1.1a is currently posted for a 45-day concurrent comment and initial ballot.

No standards modified under Project 2010-07 will be filed with regulatory authorities until the Board of Trustees has acted on the complete package of four standards.

While this summary has been updated to reflect the status of FAC-003-3 and FAC-003-X, the SDT's responses to stakeholder comments below have not changed, except as they relate to FAC-003-3 and FAC-003-X.

All comments submitted may be reviewed in their original format on the standard's project page:

[http://www.nerc.com/filez/standards/Project2010-07\\_GOTO\\_Project.html](http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html)

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 404-446-2560 or at [herb.schrayshuen@nerc.net](mailto:herb.schrayshuen@nerc.net). In addition, there is a NERC Reliability Standards Appeals Process.<sup>1</sup>

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<sup>1</sup> The appeals process is in the Standard Processes Manual: [http://www.nerc.com/files/Appendix\\_3A\\_Standard\\_Processes\\_Manual\\_20110825.pdf](http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf).



**Index to Questions, Comments, and Responses**

1. Based on stakeholder comment, the SDT clarified the applicability language of FAC-001-1 and removed the Generator Owner from R4. Do you support the proposed redline changes to FAC-001-1? (Please refer to the posted FAC-001-1 technical justification document for more information about the SDT’s rationale for its changes.) ..... 12

2. Do you support the one year compliance timeframe for Generator Owners as proposed in the Implementation Plan for FAC-001-1? ..... 29

3. With respect to FAC-003, many commenters focused on the half-mile qualifier in FAC-003. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: “...that extends greater than one mile beyond the fenced area of the generating station switchyard...” We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.

Taking into consideration that only one of the versions of FAC-003 will actually be implemented, a decision that will be made as Project 2007-07—Vegetation Management moves forward, do you support the proposed redline changes to FAC-003-X and FAC-003-3? ..... 34

4. Do you support compliance timeframe for Generator Owners as included and explained in the Implementation Plans for FAC-003-X? ..... 50

5. In the FAC-003-3 implementation plan, the SDT has attempted to account for a number of different scenarios that could play out with respect to the filing and approvals of FAC-003-2 and FAC-003-3. Do you support this approach? If there are other scenarios that the SDT needs to account for, please suggest them here. .... 57

6. In its technical justification document, the SDT reviews all standards that had been proposed for substantive modification in the Ad Hoc Group’s original support and explains why, with the exception of FAC-003, modifying them would not provide any reliability benefit. Do you support these justifications? If you believe the SDT needs to add more information to its rationale for any of these decisions, please include suggested language here. .... 63

7. The SDT is attempting to modify a set of standards so that radial generator interconnection Facilities are appropriately accounted for in NERC’s Reliability Standards, both to close reliability

- gaps and to prevent the unnecessary registration of GOs and GOPs at TOs and TOPs. Does the set of standards currently posted achieve this goal? ..... 74
- 8. If you answered “yes” to Question 7, are the modifications the SDT has made in this posting the appropriate ones? ..... 87
- 9. If you answered “no” to Question 7, what standards need to be added or removed to achieve the SDT’s goal? Please provide technical justification for your answer. .... 91
- 10. Do you have any other comments that you have not yet addressed? If yes, please explain. .... 99

**The Industry Segments are:**

- 1 — Transmission Owners
- 2 — RTOs, ISOs
- 3 — Load-serving Entities
- 4 — Transmission-dependent Utilities
- 5 — Electric Generators
- 6 — Electricity Brokers, Aggregators, and Marketers
- 7 — Large Electricity End Users
- 8 — Small Electricity End Users
- 9 — Federal, State, Provincial Regulatory or other Government Entities
- 10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment										
				1	2	3	4	5	6	7	8	9	10	
1.	Group	Gerald Beckerle	SERC OC Standards Review Group	X		X								
1.	Scott Brame	NCEMC	SERC 1, 3, 4, 5											
2.	Troy Willis	Georgia Transmission Corp.	SERC 1											
3.	Mike Hirst	Cogentrix	SERC 5											
4.	Bob Dalrymple	TVA	SERC 1, 3, 5, 6											
5.	Matt Carden	Southern Co.	SERC 1, 5											
6.	Shardra Scott	Gulf Power Co.	SERC 3											
7.	Kerry Sibley	Georgia Transmission Corp.	SERC 1											
8.	Andy Burch	EEL	SERC 5											
9.	Shaun Anders	City of Springfield (CWLP)	SERC 1, 3											
10.	Melinda Montgomery	Entergy	SERC 1, 3, 5											
11.	John Troha	SERC Reliability Corp	SERC 10											
2.	Group	Jonathan Hayes	Southwest Power Pool Standards Development Team		X									
<b>Additional Member</b>		<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>										

Group/Individual	Commenter	Organization	Registered Ballot Body Segment																
			1	2	3	4	5	6	7	8	9	10							
1. Jonathan Hayes	Southwest Power Pool	SPP	2																
2. Robert Rhodes	Southwest Power Pool	SPP	2																
3. Don Taylor	Westar	SPP	1, 3, 5, 6																
4. John Allen	City Utilities of Springfield	SPP	1, 4																
5. Sean Simpson	MCPBPU	SPP	1, 3, 5																
6. Louis Guidry	CLECO	SPP	1, 3, 5																
7. Mitch Williams	Western Farmers	SPP	1, 3, 5																
8. Valerie Pinnamonti	AEP	SPP	1, 3, 5																
9. Bud Averill	Grand River Dam Authority	SPP	1, 3, 5																
10. Terri Pyle	OGE	SPP	1, 3, 5																
3.	Group	Guy Zito, Guy Zito	Northeast Power Coordinating Council, Northeast Power Coordinating Council																X
	<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>															
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC, NPCC	10															
2.	Greg Campoli	New York Independent System Operator	NPCC, NPCC	2															
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC, NPCC	1															
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC, NPCC	1															
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC, NPCC	10															
6.	Brian Evans-Mongeon	Utility Services	NPCC, NPCC	8															
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC, NPCC	5															
8.	Kathleen Goodman	ISO - New England	NPCC, NPCC	2															
9.	Chantel Haswell	FPL Group, Inc.	NPCC, NPCC	5															
10.	David Kiguel	Hydro One Networks Inc.	NPCC, NPCC	1															
11.	Michael R. Lombardi	Northeast Utilities	NPCC, NPCC	1															
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC, NPCC	9															
13.	Bruce Metruck	New York Power Authority	NPCC, NPCC	6															
14.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC, NPCC	10															
15.	Robert Pellegrini	The United Illuminating Company	NPCC, NPCC	1															
16.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC, NPCC	1															
17.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC, NPCC	5															
18.	Saurabh Saksena	National Grid	NPCC, NPCC	1															
19.	Michael Schiavone	National Grid	NPCC, NPCC	1															

Group/Individual	Commenter	Organization	Registered Ballot Body Segment											
			1	2	3	4	5	6	7	8	9	10		
20. Wayne Sipperly	New York Power Authority	NPCC, NPCC 5												
21. Tina Teng	Independent Electricity System Operator	NPCC, NPCC 2												
22. Donald Weaver	New Brunswick System Operator	NPCC, NPCC 2												
23. Ben Wu	Orange and Rockland Utilities	NPCC, NPCC 1												
24. Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC, NPCC 3												
4. Group	Emily Pannel	Southwest Power Pool Regional Entity												X
No additional members listed.														
5. Group	Will SMith	MRO NSRF	X	X	X	X	X	X	X	X				X
<b>Additional Member Additional Organization Region Segment Selection</b>														
1.	Mahmood Safi	OPPD	MRO	1, 3, 5, 6										
2.	Chuck Lawrence	ATC	MRO	1										
3.	Jodi Jenson	WAPA	MRO	1, 6										
4.	Ken Goldsmith	ALTW	MRO	4										
5.	Alice Ireland	XCEL/NSP	MRO	1, 3, 5, 6										
6.	Dave Rudolph	BEPC	MRO	1, 3, 5, 6										
7.	Eric Ruskamp	LES	MRO	1, 3, 5, 6										
8.	Joe DePoorter	MGE	MRO	3, 4, 5, 6										
9.	Scott Nickels	RPU	MRO	4										
10.	Terry Harbour	MEC	MRO	1, 3, 5, 6										
11.	Marie Knox	MISO	MRO	2										
12.	Lee Kittelson	OTP	MRO	1, 3, 4, 5										
13.	Scott Bos	MPW	MRO	1, 3, 5, 6										
14.	Tony Eddleman	NPPD	MRO	1, 3, 5										
15.	Mike Brytowski	GRE	MRO	1, 3, 5, 6										
16.	Richard Burt	MPC	MRO	1, 3, 5, 6										
6. Group	Charles W. Long	SERC Planning Standards Subcommittee	X											X
<b>Additional Member Additional Organization Region Segment Selection</b>														
1.	Pat Huntley	SERC	SERC	10										
2.	John Sullivan	Ameren Services Co.	SERC	1										
3.	Philip Kleckley	SC Electric & Gas Co.	SERC	1										
4.	Bob Jones	Southern Company Services	SERC	1										

Group/Individual	Commenter	Organization	Registered Ballot Body Segment													
			1	2	3	4	5	6	7	8	9	10				
5. Jason Adams	TVA	SERC 1														
7. Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X								
<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>													
1. Timothy Beyrle	City of New Smyrna Beach	FRCC	4													
2. Greg Woessner	Kissimmee Utility Authority	FRCC	3													
3. Jim Howard	Lakeland Electric	FRCC	3													
4. Lynne Mila	City of Clewiston	FRCC	3													
5. Joe Stonecipher	Beaches Energy Services	FRCC	1													
6. Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4													
7. Randy Hahn	Ocala Utility Services	FRCC	3													
8. Group	Mike Garton	Dominion	X		X		X	X								
<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>													
1. Michael Gildea	Dominion Resources Services, Inc.	RFC	5, 6													
2. Connie Lowe	Dominion Resources Services, Inc.	NPCC	5, 6													
3. Michael Crowley	Virginia Electric and Power Company	RFC	1, 3													
9. Group	Annette M. Bannon	PPL NERC Registered Affiliates			X		X	X								
<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>													
1. Brent Ingebrigston	LG&E and KU Services Co.	SERC	3													
2. Don Lock	PPL Brunner Island, LLC	RFC	5													
3.	PPL Martins Creek, LLC	RFC	5													
4.	PPL Holtwood, LLC	RFC	5													
5.	PPL Montour, LLC	RFC	5													
6.	Lower Mount Bethel Energy, LLC	RFC	5													
7. Annete Bannon	PPL Susquehanna, LLC	RFC	5													
8. Leland McMillan	PPL Montana, LLC	WECC	5													
10. Group	Jason Marshall	ACES Power Marketing Standards Collaborators														
<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>													
1. Mohan Sachdeva	Buckeye Power	RFC	3, 5, 6													
2. Erin Woods	East Kentucky Power Cooperative	SERC	1, 3, 5, 6													
3. Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6													

Group/Individual		Commenter	Organization	Registered Ballot Body Segment											
				1	2	3	4	5	6	7	8	9	10		
11.	Group	Steve Rueckert	Western Electricity Coordinating Council												X
No additional members listed.															
12.	Individual	Jack Cashin	Electric Power Supply Association					X	X						
13.	Individual	Natalie McIntire	American Wind Energy Association					X							
14.	Individual	Tom Flynn	Puget Sound Energy, Inc.	X				X	X						
15.	Individual	Silvia Parada Mitchell	Compliance & Responsibility Organization	X		X		X	X						
16.	Individual	Antonio Grayson	Southern Company	X		X		X	X						
17.	Individual	Chris Higgins/Stephen Enyeart/Chuck Mathews/Charles Sheppard	Bonneville Power Administration	X		X		X	X						
18.	Individual	Thad Ness	American Electric Power	X		X		X	X						
19.	Individual	Carla Bayer	BP Wind Energy North America Inc.					X							
20.	Individual	John Bee on behalf of Exelon	Exelon	X				X							
21.	Individual	Dennis Sismaet	Seattle City Light	X		X	X	X	X						
22.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP (Occidental Chemical)					X							
23.	Individual	Michael Falvo	Independent Electricity System Operator		X										
24.	Individual	Greg Rowland	Duke Energy	X		X		X	X						
25.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X											
26.	Individual	Kirit Shah	Ameren	X		X		X	X						
27.	Individual	John Seelke	PSEG	X		X		X	X						
28.	Individual	Andrew Z. Pusztai	American Transmission Company	X											
29.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X						
30.	Individual	Ravi Bantu	RES Americas Development					X							
31.	Individual	Katy Wilson	Sempra Generation					X							

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
32.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
33.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
34.	Individual	Ed Davis	Entergy Services	X		X		X	X				
35.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
36.	Individual	Russell A. Noble	Cowlitz County PUD			X	X	X					
37.	Individual	Anthony Jablonski	ReliabiltyFirst										X
38.	Individual	Donald Jones	Texas Reliability Entity										X
39.	Individual	Amir Hammad	Constellation Power Source Generation					X					
40.	Individual	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				



1. **Based on stakeholder comment, the SDT clarified the applicability language of FAC-001-1 and removed the Generator Owner from R4. Do you support the proposed redline changes to FAC-001-1? (Please refer to the posted FAC-001-1 technical justification document for more information about the SDT’s rationale for its changes.)**

#### Summary Consideration:

The SDT thanks all stakeholders for their comments and their 87% approval for the FAC-001-1 changes posted for ballot in November 2011. Based on stakeholder feedback, the SDT has made the following minor changes to FAC-001-1:

-Corrected a typo in Applicability section 4.2.1 to change “within” to “with.”

-Corrected a typo in the VSLs for R3 to ensure that parts 3.1.1 through 3.1.16 were referenced, rather than just 3.1.1 through 3.1.6.

-Changed references to “Transmission System” to “interconnected Transmission systems” to ensure consistency with the language elsewhere in the standard and in FAC-002-1.

Some stakeholders remain concerned about the intent of the SDT’s work on FAC-001-1. The SDT reminded them that the scope is addressed in the SAR. The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT determined that it should first address “low-hanging fruit” and believes these to be sole-use Facilities (see posted examples under “Supporting Materials”) – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP). Through its deliberations, the SDT concluded that an interconnection Facility owned or operated by a GO or GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT.

Concerned commenters were also referred to one of the SDT’s resource documents: [Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document](#).

Some commenters suggested changes to Requirements R1 or R4, which deal exclusively with the Transmission Operator and are outside the scope of the SDT’s work.

One commenter suggested formatting changes. The SDT agrees with the commenter that there are a number of ways to format the standard with this SDT’s revisions. However, the majority of stakeholders support the current format of the standard and no change was made.

One commenter suggested that the phrase “Generator Owner’s existing Facility” be changed to “Generator Owner’s existing Transmission Facility.” The SDT does not agree with labeling a GO’s Facility as “Transmission,” in part because in

some areas (like Texas), GOs, by statute, can't own Transmission. It was also brought to the SDT's attention that in most cases, the Facility in question is referred to as the Interconnection Facility in documents filed by the GO with FERC. Therefore, the SDT intentionally modified language so that a Facility owned by a generation entity did not contain the term "Transmission."

One commenter did not agree with the overall clarifying change to the Applicability section, but the SDT reminded this commenter that this change was made to address previous comments that indicated that there was uncertainty as to whether "another Facility to its existing generation Facility" was meant to address connecting additional generators by the same GO. The SDT intends FAC-001-1 to apply only when the GO of an existing Facility executes an agreement to evaluate the reliability impact of connecting additional generation owned by another GO. No change made with respect to this comment.

A few stakeholders were concerned with the 45-day time frame included in the standard. The SDT pointed out that majority of stakeholders and the SDT support 45 days as a sufficient time frame because in many cases, the GO would simply need to adopt (document and publish) the Facility connection requirements of its TO. No change to that time frame was made.

Organization	Yes or No	Question 1 Comment
Manitoba Hydro	Negative	The intention of the NERC SDT in revising these standards is not clear. While the Technical Justification document states that the SDT intended to focus on a Generator Owner's radial interconnection facilities, the scope of the revised standard (s) is not confined to such facilities. The very broadly defined term "Facility" is used. Moreover, the Technical Justification document's reference to the FERC decision in Cedar Creek as a basis for the revision of additional standards is confusing, since that decision did not specifically address the issue of radial facilities and supported NERC's registration of GOs as TOs.
<p><b>Response:</b> Thank you for your comment. The scope of this SDT is addressed in the <a href="#">SAR</a>. The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT determined that it should first address "low-hanging fruit" and believes these to be sole-use Facilities (see posted examples under "Supporting Materials") – that is, a Facility used to connect one or more generators to a Facility owned or operated by a</p>		

Organization	Yes or No	Question 1 Comment
<p>transmission entity (TO/TOP). Through our deliberations, we came to the conclusion that an interconnection Facility owned or operated by a GO or GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT.</p> <p>The SDT also refers the commenter to the document titled <a href="#">Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document</a>. Specifically, see the last paragraph on page 4 and first two on page 5.</p>		
Southern Company	No	<p>1) R4 is duplicative of R1 - either remove "maintain" from R1 or delete R4 - both instances of "maintain" are not needed.â€¢ 2) The measures, as written, provide no additional indication of the evidence that could be presented to demonstrate compliance with the Reliability Standard Requirements. They provide little guidance on assessing non-compliance with the Requirements. â€¢</p>
<p><b>Response:</b> Thank you for your comment. We agree with your suggestions, but both are outside the scope of this SDT. These items will be submitted to the Issues Database to be addressed in a future revision of FAC-001.</p>		
Southwest Power Pool Standards Development Team	No	<p>Based on the applicability section of FAC-001 we feel that the strike through should have been kept. It limited the requirement to just those generator owners who had agreements in place, which we feel is appropriate.</p>
<p><b>Response:</b> Thank you for your comment. This change was made to address previous comments that indicated to the SDT there was uncertainty as to whether this was meant to address connecting additional generators by the same GO. The SDT intends FAC-001 to apply only when the GO of an existing Facility executes an agreement to evaluate the reliability impact of connecting additional generation owned by another GO. No change made with respect to this comment.</p>		
Texas Reliability Entity	No	<p>In Section 5.1, the reference to Regional Entity should be removed. There are no requirements that apply to the Regional Entity.</p> <p>In Requirements R1 and R4, "Planning Coordinator" should be added after "Regional Entity." In the ERCOT Region it is the Planning Coordinator that maintains planning criteria and connection requirements. There is no NERC</p>

Organization	Yes or No	Question 1 Comment
		<p>requirement or any obligation (as indicated in the technical justification document) on the part of a GO to specifically execute an Agreement to evaluate the reliability impact of interconnecting a third party Facility. Therefore, this requirement’s applicability is contingent on a prerequisite that may not occur, and that is under the control of the GO. This assumption on the part of the SDT unnecessarily complicates the compliance monitoring and enforcement of this standard. For instance, if an “Agreement” is not executed, a GO is not required to comply with the requirement, even though the GO may ultimately interconnect with another entity. The requirement should be modified to include an applicability trigger similar to that of FAC-002-1, so that once a GO “seek[s] to integrate . . .,” i.e., agrees to or is compelled to allow a third-party interconnection, then the requirement becomes applicable. Otherwise, the compliance and monitoring is subject to the SDT’s speculation as indicated in this language included in the technical justification document: “However, the SDT cannot be certain this is the only example and it therefore proposes to add this new requirement to FAC-001-1. In doing so, the SDT acknowledges that the Generator Owner may not, at the time it agrees or is compelled to allow a third party to interconnect, have the necessary expertise to conduct the required interconnect studies to meet this standard. Assuming that a regulatory body would require a Generator Owner to evaluate such an interconnection request, the SDT expects the Generator Owner and the third party to execute some form of an Agreement.”</p>
<p><b>Response:</b> Thank you for your comment. All of these comments are outside the scope of the <a href="#">SAR</a> and the SDT’s work because they refer specifically to the sections and requirements that apply to the TO alone. We encourage you to consider submitting a SAR that addresses your concerns.</p>		
Manitoba Hydro	No	<p>Manitoba Hydro has the following comments:</p> <ol style="list-style-type: none"> <li>1) The intention of the NERC SDT in revising these standards is not clear.</li> </ol>

Organization	Yes or No	Question 1 Comment
		<p>While the Technical Justification document states that the SDT intended to focus on a Generator Owner’s radial interconnection facilities, the scope of the revised standard (s) is not confined to such facilities. The very broadly defined term “Facility” is used. Moreover, the Technical Justification document’s reference to the FERC decision in Cedar Creek as a basis for the revision of additional standards is confusing, since that decision did not specifically address the issue of radial facilities and supported NERC’s registration of GOs as TOs.</p> <p>2) If the drafting team intends to limit the scope of FAC-001-1 to GO owned radial generator interconnection facilities that are not deemed BES transmission and therefore would not require the registration of the GO as a TO, Manitoba Hydro disagrees with the proposed changes to FAC-001-1 as Generator Owners may not have the models or expertise to perform interconnection studies to determine if there is an impact on the Transmission Network. This concern is echoed in the technical justification document provided by NERC: ‘the SDT acknowledges that the Generator Owner may not, at the time it agrees or is compelled to allow a third part to interconnect, have the necessary expertise to conduct the required interconnect studies to meet this standard... the Generator Owner will have to acquire such expertise. How the Generator Owner chooses to do so is not for the SDT to determine.’ Although it may not be for the SDT to determine how a GO obtains technical expertise, ensuring that such expertise is acquired before a GO conducts the required interconnection studies should be a concern to NERC as this directly affects the reliability of the BES. As a result, all interconnection requests should be implemented by the TO providing the GO with connection to the BES regardless if the interconnection point is within a Generation Owner facility or End-User facility as the TO is in the best position to set unbiased connection requirements to ensure the reliability of the BES is maintained. If the scope of FAC-001-1 also applies to GO owned BES transmission facilities, Manitoba</p>

Organization	Yes or No	Question 1 Comment
		<p>Hydro strongly believes that the Compliance Registry should apply and the GOs should be required to register as a TO and abide by all applicable standards to that functional type. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. Reliability gaps would be better addressed if select GOs and GOPs registered as TOs and TOPs to ensure all reliability standards, including the protection standards, are met so the reliability of the BES is maintained. At this time, this would not lead to a large number of extra registrations since, as stated in the technical justification document, ‘interconnection requests for Generator Owner Facilities are still relatively rare.</p> <p>3) If the redline changes are implemented, GOs are removed from R4, thereby removing the obligation for GOs to maintain their connection requirements. If GOs are included in FAC-001, they should be held accountable to the same level as TOs and should be required to maintain their connection requirements. Requiring a GO to maintain connection requirements would be especially beneficial to the GO themselves. In the majority of instances, any GO that is an Applicable Entity for FAC-001 would initially be inexperienced in performing interconnection studies and would benefit from regular and frequent review of their connection requirements as experience and expertise are gained.</p> <p>4) The revision to FAC-001-1 R2 may be problematic, depending on what was intended. Under the revised requirement, the obligation to comply is dependent on the execution of an agreement to evaluate reliability impacts under FAC-002-1. However, FAC-002-1 does not clearly require the execution of an agreement by the Generator Owner. FAC-002-1 only requires the Generator Owner to “coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority”. Accordingly if a Generator Owner coordinates without executing an agreement to perform an assessment, compliance with FAC-001 R1 will not</p>

Organization	Yes or No	Question 1 Comment
		<p>be required.</p> <p>5) Manitoba Hydro would also like to point out that if the redline changes are implemented, it will greatly increase the complexity of coordination required under FAC-002-1 for Transmission Planners/Planning Authorities.</p>
<p><b>Response:</b> Thank you for your comment. The scope of this SDT is addressed in the <a href="#">SAR</a>. The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP).</p> <p>The intent of the modifications to this standard is to address the requirements of the GO prior to the interconnection of the third party to their Facilities. The reliability gap the SDT intends to close is the need for the GO to develop Facility connection requirements prior to interconnection. The SDT does agree that upon interconnection of a third party, other standards or registrations may apply as appropriate.</p> <p>The SDT also refers the commenter to the document titled <a href="#">Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document</a>, which is posted on the project page. Specifically, see the last paragraph on page 4 and first two on page 5.</p>		
Tennessee Valley Authority	No	<p>Suggest that the overall structure of the standard be revised such that R1 - R3 are applicable to the Transmission Owner (consistent with existing FAC-001-0) and R4 (the new requirement) is applicable to the “applicable Generator Owner”. See further comments below. Support the proposed revisions to R1 and R4, but suggest R4 be returned to R3 (consistent with existing FAC-001-0).R3 in the balloted standard should be returned to R2 (consistent with existing FAC-001-0) and only be applicable to the Transmission Owner. R3.1 (or R2.1 if moved back) should be “fixed”, but it may be beyond this SDT’s charge. The use of “above” in the FAC-001-0 standard, or the proposed reference to “Requirements R1 or R2” in the proposed standard do not make sense in combination with the colon used at the end of the requirement. Suggest that R3.1 (or 2.1 if moved back) be revised as written below and all sub-requirements of R3.1 be elevated (R3.1.1 becomes R3.2, R3.1.2 becomes R3.3, etc.).”R3.1 Performance</p>

Organization	Yes or No	Question 1 Comment
		<p>requirements and/or planning criteria used to assess system impacts.” R2 in the balloted standard should become R4 and modified to incorporate the connection requirements contained in R3 that can more reasonably be expected of an “applicable Generator Owner”. For instance, an “applicable Generator Owner” might simply have a connection requirement for a third party that addresses coordination of system impact studies with the appropriate Transmission Owner(s), in lieu of R3.1, R3.1.1, and R3.1.2. Suggest that R2 (or R4 if moved below existing FAC-001-0 requirements) be revised as written below.”R2 Each applicable Generator Owner that has agreed to allow a third party Facility owner (Generation Facility, Transmission Facility, or End-user Facility) to connect to the Transmission system through use of pre-existing applicable Generator Owner Facilities shall communicate it’s Facility connection requirements to the third party. The applicable Generator Owner Facility connection requirements shall address the following items: R2.1 Coordination of system impact studies with the Transmission Owner. R2.2 Voltage level and MW and MVAR capacity or demand at point of connection. R2.3 Breaker duty and surge protection. R2.4 System protection and coordination R2.5 Metering....” Etc.</p>
<p><b>Response:</b> Thank you for your comment. We gave the comment due consideration and agree that there are a number of ways to format the standard with this SDT’s revisions. However, the majority of stakeholders support the current format of the standard. No change made.</p>		
<p>Northeast Power Coordinating Council, Northeast Power Coordinating Council</p>	<p>No</p>	<p>The intent of the draft language in FAC-001-1 is to provide guidance for addressing the alleged reliability gap that exists between GO/GOPs that own/ operate transmission facilities but are not registered as TO/TOPs. The impact of the revised language will depend on the characterization of the generator lead after the “third party “ connects to the existing generator lead. IF the generator lead is owned by the TO utility after the third party connection : The proposed DRAFT FAC-001 language suggests that within 45 days of a 3rd party having an executed Agreement to evaluate the reliability</p>



Organization	Yes or No	Question 1 Comment
		<p>impact of interconnecting, the existing generator needs to document and publish facility connection requirements. The proposed language suggests that a third party can commandeer existing generators leads and interconnect. A reclassification would be required because “third party” power would flow through the downstream portions of the existing leads. This introduces significant challenges for defining ownership / transfer of installed assets as well as real property, easements, operational jurisdiction, O&amp;M cost responsibility, etc. The FERC approved pro-forma Attachment X Interconnection Agreement clearly states that the project Developer must meet all Applicable Reliability Standards which means that all requirements and guidelines of the Applicable Reliability Councils, and the Transmission District to which the Developer’s Large Generating Facility is directly interconnected. As an example, to accommodate this NERC proposal, the FERC approved NYISO pro-forma tariff would need to be revised to allow this “third party” use. The pro-forma interconnection tariff also states that the Developer must provide updated project information prior to the Facilities Study. The Facilities Study might not be made until several years after the Interconnection Request /Feasibility Study is made (“executed Agreement to evaluate the reliability impact of interconnecting” in this proposed draft is akin to the Interconnection Request/Feasibility Study). Placing the requirement to have the existing Generator Owner publish reliability requirements for a potential “third party user”, without the generator having any knowledge of the potential reliability outcomes or asset transfer / ownership issues is not a reasonable expectation. The interconnection of a third party to an existing generator lead would force existing generators to revise their Interconnection Agreements with FERC. The “third party”, would at a minimum, need to comply with the existing Generators reliability obligations as specified in the Interconnection Agreement. IF the third party connects to the GO owned generator lead, the GO will be considered a TO: A TO would not be involved, other than review</p>

Organization	Yes or No	Question 1 Comment
		<p>of the SRIS and Facilities reports. The difficult thing for an existing GO would be to prepare, within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility, a document listing the requirements. To allow for the above possibilities, the language for applicability of FAC-001 to GO’s or GOP’s, should be :”Each applicable Generator Owner shall, at least 60 days prior to execution of a Facilities / Class Year Study Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the Transmission System, document and publish its Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, sub regional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements.”</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees with many of the comments (as indicated in the accompanying resource document titled <a href="#">Technical Justification: FAC-001-1</a>), especially those concerning the complexities of this process. The majority of stakeholders and the SDT support 45 days as a sufficient time frame because in many cases, the GO would simply need to adopt (document and publish) the facility connection requirements of its TO. No change made.</p>		
Consolidated Edison Co. of NY, Inc.	No	<p>The language for FAC-001 Requirement R2 should be:”This requirement shall apply to each applicable Generator Owner. Generator Owner filings must be made at least 60 days in advance of execution of the final interconnection study agreement in the Planning Coordinator’s or Transmission Planner’s study process.Each applicable Generation Owner must publish its Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, sub regional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements.The evaluation of the reliability impact(s) of interconnecting a third party Facility to the Generator Owner’s existing Facility utilized for interconnection to the Transmission System must be</p>

Organization	Yes or No	Question 1 Comment
		documented.”
<p><b>Response:</b> Thank you for your comment. The SDT agrees with many of the comments (as indicated in the accompanying resource document titled <a href="#">Technical Justification: FAC-001-1</a>), especially those concerning the complexities of this process. The majority of stakeholders and the SDT support 45 days as a sufficient time frame because in many cases, the GO would simply need to adopt (document and publish) the facility connection requirements of its TO. No change made.</p>		
<p>Ingleside Cogeneration LP (Occidental Chemical)</p>	<p>No</p>	<p>Unfortunately, the vital point of this requirement revolves around whether or not a Generator Owner is compelled externally to allow access to their interconnection facilities. If the GO is driving the connection for financial or other business reasons, there is no reason they should not be responsible for developing AND maintaining a facility connection requirements document. Otherwise, when the local transmission system requirements change for any reason, there will be no entity responsible to ensure that the third party will conform as well. Conversely, if the GO should be compelled to allow access to a third party, it is the responsibility of the “compeller” to handle all the related reliability studies and documents. This may include the development of a CFR which separates reliability tasks between the GO and other entities - especially if a TSP registration is required. This ensures that the Regional Entity, PUC, RTO, or other regulator must budget dollars and resources directly related to their action - not cause them to be directed to a GO.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees with many of the comments (as indicated in the accompanying resource document titled <a href="#">Technical Justification: FAC-001-1</a>), especially those concerning the complexities of this process. However, the issues you raise are beyond the scope of the SDT and its SAR. No change made.</p>		
<p>PSEG</p>	<p>No</p>	<p>We revised this partial sentence to the following: “Each applicable Generator Owner shall, within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Transmission Facility that is used for connection</p>

Organization	Yes or No	Question 1 Comment
		<p>to the interconnected Transmission systems (under FAC-002-1), ..."- The phrase "Generator Owner's existing Facility that is used to interconnect to the Transmission System" was changed to "Generator Owner's existing Transmission Facility that is used for connection to the interconnected Transmission systems." - "Transmission" was added before Facility to exclude connections elsewhere; "Transmission System" was changed to "Transmission systems" because while "Transmission" and "System" are defined in the NERC Glossary, "System" means "A combination of generation, transmission, and distribution components." "Transmission systems" do not have generation or distribution components, so a lower case "system" is warranted. - In addition, the suggested phrase "interconnected Transmission systems" (plural "systems") uses identical language from FAC-002-1, except that we capitalized "Transmission.</p>
<p><b>Response:</b> Thank you for your comment. The SDT has addressed the proposed change to applicability according to your comments. The applicability section now reads: "Generator Owner with an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems.</p> <p>The SDT has been informed that in some areas (like Texas), GOs, by statute, can't own Transmission. It was also brought to the SDT's attention that in most cases, the Facility in question is referred to as the Interconnection Facility in documents filed by the GO with FERC. Therefore, the SDT intentionally modified language so that a Facility owned by a generation entity did not contain the term "Transmission."</p>		
Seattle City Light	Affirmative	Key points are that (1) an executed agreement is required before evaluations of impacts are necessary and (2) this only applies when a third party is connecting to the generating interconnection line.
<p><b>Response:</b> Thank you for your comment.</p>		
Electric Power Supply Association	Yes	All TO requirements for FAC-001-1 would apply if and when GO executes an Agreement to evaluate the reliability impact of interconnecting a third

Organization	Yes or No	Question 1 Comment
		<p>party Facility to its existing generation interconnection Facility. The execution of the agreement is necessary to comply with FAC-002-1 and start the compliance clock with the applicable regulatory authority. Thus as the Project 2010-07 Standard Drafting Team (SDT) in its technical justification has stated, “If, and only if, the existing owner of a generator interconnection Facility has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to its existing generation Facility” then FAC-001-1 should apply. EPSA concurs with SDT’s conclusion. The SDT has examined the issue regarding if future requests for transmission service on the interconnection Facility and in doing so acknowledged that when that Facility adopted open access and was providing transmission service it would necessitate re-evaluation of the need for the Facility to be maintained in accordance with FAC-001-1, Requirements 2 and 4. This service would indeed prompt the necessary agreement the SDT contemplates in its technical justification of FAC-001-1. EPSA believes this serves as the necessary trigger for evaluation of Requirements 2 and 4 under FAC-001-1 for GOs.</p>
<p><b>Response:</b> Thank you for your comment.</p>		
<p>American Wind Energy Association</p>	<p>Yes</p>	<p>AWEA appreciates that this standard specifies that it has limited applicability. For instance, only those generators that have an executed agreement with a third party wishing to interconnect must document and publish Facility connection requirements. We believe the proposed 45-day time window is a minimum for GO/GOP owners of generator lead lines to provide this documentation following execution of such an agreement. Anything less than 45 days could result in a burdensome and hard to meet deadline for GO/GOP staff. However, AWEA believes that extending this time window for publishing Facility connection requirements to 90 days after an executed agreement would be beneficial. We believe this will allow the GO/GOP owners of generator leads more time to coordinate with their</p>

Organization	Yes or No	Question 1 Comment
		interconnecting Transmission Providers and will result in more reliable and coordinated connection requirements for the generator lead.
<p><b>Response:</b> Thank you for your comment. The majority of stakeholders and the SDT support 45 days as a sufficient time frame because in many cases, the GO would simply need to adopt (document and publish) the facility connection requirements of its TO. No change made.</p>		
SERC OC Standards Review Group	Yes	Please verify within the applicability section (4.2.1) you intended to use the word “within” rather than some other wording.
<p><b>Response:</b> Thank you for your comment. The SDT intended it to read “Generator Owner <b>with</b> an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the Transmission System.” This change has been made.</p>		
RES Americas Development	Yes	RES Americas and AWEA appreciate that this standard specifies that it has limited applicability. For instance, only those generators that have an executed agreement with a third party wishing to interconnect must document and publish Facility connection requirements. We believe the proposed 45-day time window is a minimum for GO/GOP owners of generator lead lines to provide this documentation following execution of such an agreement. Anything less than 45 days could result in a burdensome and hard to meet deadline for GO/GOP staff. However, we believes that extending this time window for publishing Facility connection requirements to 90 days after an executed agreement would be beneficial. We believe this will allow the GO/GOP owners of generator leads more time to coordinate with their interconnecting Transmission Providers and will result in more reliable and coordinated connection requirements for the generator lead.
<p><b>Response:</b> Thank you for your comment. The majority of stakeholders and the SDT support 45 days as a sufficient time frame because in many cases, the GO would simply need to adopt (document and publish) the facility connection requirements of its TO</p>		

Organization	Yes or No	Question 1 Comment
No change made.		
ACES Power Marketing Standards Collaborators	Yes	We largely agree with the changes the drafting team made but believe some additional changes are necessary. In section 4.2.1 of the Applicability Section, “within” should be “with”. Because NERC’s Glossary of Terms establishes that an Agreement can be verbal and not enforceable by law, section 4.2.1 should be further modified to clarify that it is a legally enforceable and fully executed Agreement. The language in R3 in parenthesis after Generation Owner should be modified to “once required by Requirement R2”. This makes it clearer that R3 does not apply until the GO has an executed Agreement to evaluate a request by a third part to interconnect.
<p><b>Response:</b> Thank you for your comment. We agree that “within” should be “with”. The SDT chose not to adopt the second recommendation as the requirement already contains the term “executed.” The SDT also chose not to adopt the third recommendation as the requirement already contains the parenthetical (in accordance with Requirement R2) which we feel is synonymous with the comment.</p>		
Southwest Power Pool Regional Entity	Yes	
MRO NSRF	Yes	
SERC Planning Standards Subcommittee	Yes	
Florida Municipal Power Agency	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	

Organization	Yes or No	Question 1 Comment
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Exelon	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
Ameren	Yes	
American Transmission Company	Yes	
South Carolina Electric and Gas	Yes	
Sempra Generation	Yes	
Xcel Energy	Yes	
Cowlitz County PUD	Yes	
Constellation Power Source Generation	Yes	
ReliabiltyFirst		
Entergy Services		



Organization	Yes or No	Question 1 Comment
Western Electricity Coordinating Council		
Puget Sound Energy, Inc.		
Compliance & Responsibility Organization		
Bonneville Power Administration		

**2. Do you support the one year compliance timeframe for Generator Owners as proposed in the Implementation Plan for FAC-001-1?**

**Summary Consideration:**

The vast majority of commenters supported the one year compliance time frame in the Implementation Plan. A few commenters were concerned with this time frame and associated enforcement, in part based on similar issues addressed in recent CANs. The SDT did its best to clarify its intent as follows:

The SDT’s intent is that the mandatory date (the date upon which the GO must be compliant with applicable requirements and measures) be the first calendar day of the first calendar quarter one year after FAC-001-1’s approval. The SDT believes one year is sufficient time for the GO to become compliant where it has one or more in-place (which we interpret as synonymous with legacy or grandfathered) executed Agreement(s). If an Agreement is executed after the mandatory date, then the GO has 45 days to “document and publish its Facility connection requirements” (R2) and those requirements shall address items under R3.

No changes were made to the Implementation Plan.

Organization	Yes or No	Question 2 Comment
Ingleside Cogeneration LP (Occidental Chemical)	No	Based upon similar issues addressed in Compliance Application Notices (CANs), the drafting team needs to specify how the requirements apply to an in-place “executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the Transmission System.” In the view of Ingleside Cogeneration LP, if the Agreement takes effect even one day before FAC-001-1 does, requirements R2 and R3 do not apply. Without this clarification, it is possible that NERC’s Compliance team will apply the requirements retroactively - with minimum industry input.
<p><b>Response:</b> Thank you for your comment. The SDT’s intent is that the mandatory date (the date upon which the GO must be compliant with applicable requirements and measures) be the first calendar day of the first calendar quarter <u>one year after its approval</u>. The SDT believes one year is sufficient time for the GO to become compliant where it has one or more in-place (which we interpret as synonymous with legacy or grandfathered) executed Agreement(s). If an Agreement is executed after the mandatory date, then the GO has 45 days to “document and publish its Facility connection requirements” (R2) and those requirements shall</p>		

Organization	Yes or No	Question 2 Comment
address items under R3.		
Southwest Power Pool Regional Entity	No	No action is required unless a GO has an executed third-party agreement. If a GO has an agreement, the standard already includes a 45-day timeframe for the GO to document and publish its facility connection requirements.
<p><b>Response:</b> Thank you for your comment. The SDT’s intent is that the mandatory date (the date upon which the GO must be compliant with applicable requirements and measures) be the first calendar day of the first calendar quarter <u>one year after its approval</u>. The SDT believes one year is sufficient time for the GO to become compliant where it has one or more in-place (which we interpret as synonymous with legacy or grandfathered) executed Agreement(s). If an Agreement is executed after the mandatory date, then the GO has 45 days to “document and publish its Facility connection requirements” (R2) and those requirements shall address items under R3.</p>		
Southern Company	No	See our response to Question 9.
<p><b>Response:</b> See the SDT’s response to Question 9.</p>		
Manitoba Hydro	No	See question 1 comments.
<p><b>Response:</b> See SDT’s response to Question 1.</p>		
Cowlitz County PUD	Yes	Cowlitz PUD (District) registered as a Transmission Owner shortly before FAC-001-0 became effective and was forced to file a Mitigation Plan in order to facilitate compliance. The District successfully completed compliance implementation and documentation in eight months. The proposed one year compliance timeframe is sufficient.
<p><b>Response:</b> Thank you for your comment and support.</p>		
Seattle City Light	Yes	The proposed changes for FAC-001-1 state a 45 day period to complete the evaluation. Not sure what the question is referring to regarding “ 1 year “?

Organization	Yes or No	Question 2 Comment
<p><b>Response:</b> Thank you for your comment. The SDT’s intent is that the mandatory date (the date upon which the GO must be compliant with applicable requirements and measures) be the first calendar day of the first calendar quarter <u>one year after its approval</u>. The SDT believes one year is sufficient time for the GO to become compliant where it has one or more in-place (which we interpret as synonymous with legacy or grandfathered) executed Agreement(s). If an Agreement is executed after the mandatory date, then the GO has 45 days to “document and publish its Facility connection requirements” (R2) and those requirements shall address items under R3.</p>		
<p>American Wind Energy Association / RES Americas Development</p>	<p>Yes</p>	<p>Yes, since there is no exigent reason why this standard needs to be put in place at once, we support the one-year compliance timeframe. We believe that it will allow generators a reasonable time to comply with the requirement.</p>
<p><b>Response:</b> Thank you for your comment and support.</p>		
<p>SERC OC Standards Review Group</p>	<p>Yes</p>	
<p>Southwest Power Pool Standards Development Team</p>	<p>Yes</p>	
<p>Northeast Power Coordinating Council, Northeast Power Coordinating Council</p>	<p>Yes</p>	
<p>MRO NSRF</p>	<p>Yes</p>	
<p>SERC Planning Standards Subcommittee</p>	<p>Yes</p>	
<p>Florida Municipal Power Agency</p>	<p>Yes</p>	

Organization	Yes or No	Question 2 Comment
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Electric Power Supply Association	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Exelon	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
Ameren	Yes	
PSEG	Yes	
American Transmission Company	Yes	

Organization	Yes or No	Question 2 Comment
South Carolina Electric and Gas	Yes	
Sempra Generation	Yes	
Xcel Energy	Yes	
Constellation Power Source Generation	Yes	
Western Electricity Coordinating Council		
Puget Sound Energy, Inc.		
Compliance & Responsibility Organization		
Bonneville Power Administration		
Consolidated Edison Co. of NY, Inc.		
Entergy Services		
ReliabilityFirst		
Texas Reliability Entity		

3. With respect to FAC-003, many commenters focused on the half-mile qualifier in FAC-003. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: “...that extends greater than one mile beyond the fenced area of the generating station switchyard...” We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.

Taking into consideration that only one of the versions of FAC-003 will actually be implemented, a decision that will be made as Project 2007-07—Vegetation Management moves forward, do you support the proposed redline changes to FAC-003-X and FAC-003-3?

#### Summary Consideration:

The SDT thanks all stakeholders for their comments and their over 85% approval for the FAC-003-X and FAC-003-3 changes posted for ballot in November 2011. Based on stakeholder feedback, the SDT has made the following changes:

- Added a clarifying reference to line of sight in the GO exemption in section 4.3.1.
- Corrected a typo in 4.3.1.2 of FAC-003-3.
- Changed “RE” to “Regional Entity” in 4.3.1 of FAC-003-X.

As it discusses in the document titled “[Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface](#),” the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.

To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight. 4.3.1 of FAC-003-X now reads:

Generator Owner that owns an overhead transmission line(s) that (1) extends greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) does not have a clear line of sight from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and is operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.

4.3.1 of FAC-003-3 now reads:

Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) do not have a clear line of sight from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and are: Operated at 200kV or higher; or operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

Both references to clear line of sight include a footnote stating: "Clear line of sight' means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day."

With this reference, the SDT simply seeks to clarify the exception language based on the intent that has been agreed upon by the stakeholder body. In its [Consideration of Comments report](#) from the last formal comment period, which ended on July 17, 2011, the SDT explained "We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor." With the addition of an explicit line of sight reference here, the SDT believes it has clarified its original intent and appropriately considered all comments submitted.

Some stakeholders suggested changes that should have been submitted when Project 2007-07 was revising FAC-003-2, because these suggestions dealt with the standard as a whole rather than the changes made by this SDT to ensure that GOs are included in the standard's applicability.

One commenter remains concerned about the scope of the SDT. The SDT reminded this commenter that its scope is addressed in the [SAR](#) and that its intent is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT also refers the commenter to the document titled



Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document. Specifically, see the last paragraph on page 4 and first two on page 5.

Organization	Yes or No	Question 3 Comment
Ameren Services	Negative	<p>(a) There is no technical basis for the one mile length exemption. In fact, one could argue that a very short line, 300 feet in length, that experienced a fault from a tree at "the end of the circuit", i.e near the switchyard fence, would have much more of an impact on the BES because the fault would be limited by much less impedance.</p> <p>(b) It is also unclear in this version if a GO that owned one line that was 1.2 miles in length would have to comply for the entire length of said line, or just 0.2 miles of said line. If the GO is responsible for 1.2 miles, then that argues that the first mile is important and consequently there is no basis for ignoring the first mile on other lines. If the GO is only responsible for 0.2 miles, what is the technical basis to ignore a mile? And would it be the first mile from the switchyard that is ignored, or is the middle mile, or the last mile where it connects to the TO? Or could the GO decide? Or could the GO pick sections of the line that amount to a mile that they can ignore? This seems like something that should be addressed for compliance.</p> <p>(c) The 2 year compliance time line is far too long. There is significant industry evidence that was developed in the drafting of Version 2 that supports a one year compliance time-line for new lines. This is evidenced in Version 2. Thus there is no basis for the 2 years</p>
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled "<a href="#">Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface</a>," the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight.</p> <p>With respect to your second comment, the SDT intended for the length qualifier to be just that; if the overhead portion of a Facility</p>		

Organization	Yes or No	Question 3 Comment
<p>exceeds the distance, <a href="#">the entire Facility</a> is subject to the requirements of the standard.</p> <p>The SDT chose the time in the implementation plan based upon reasons it documented in the <a href="#">accompanying implementation plan</a> and also based upon comments of stakeholders.</p>		
Wisconsin Public Service Corp Electric Cooperative	Negative	R1.2 refers to an encroachment due to a fall in. This is confusing because according to the dictionary “Webster’s II” encroachment reads: “to intrude gradually”, and a ‘fall in’ is not usually gradual.
<p><b>Response:</b> Thank you for your comment. This is outside the scope of the <a href="#">SAR</a>. The SDT reviewed comments submitted as part of the <a href="#">Project 2007-07</a> effort and did not find this comment had been submitted.</p>		
Wisconsin Public Service Corp.	Negative	<p>The concern with the proposed wording is that many generating station may not have a “generating station switchyard” as implied by the proposed wording. Often the generator leads (e.g. 20 kV) will exit the generator and connect to transformers located in transformer bays directly adjacent to the plant. From the transformers the now greater than 200 kV lines will be routed to the point of interconnect or a generating unit switchyard, possibly miles or yards away. By no one’s definitions would the transformer bays adjacent to the plant be considered a switchyard. The plant fence may be yards or hundreds of yards from the bays and on a multiple unit site, there may be a site fence or boundary, which could be comprise of fences, security patrols, or other barriers yards or miles from the transformer but enveloping the switchyard. The valid assumption made by the drafting team is that transmission lines within an area tightly controlled by the generator operator poses very little risk to the BES as a result of vegetation contact. This assumption is based on the valid observation that these areas are routinely occupied and observed by station personnel and as a result unexpected and unacceptable vegetation growth is highly unlikely because it is controlled by routine maintenance. It also correctly assumes that some distance past the controlled area is acceptable since this area would also be under near continuous observation. The problem comes in defining both a tightly controlled area and a line of site. We suggest the following: Controlled Area: A</p>

Organization	Yes or No	Question 3 Comment
		<p>perimeter around a power plant, power plants, or switchyard which is prevents intrusion by the use of physical barriers, observation, or electronic monitoring and is routinely occupied such that unexpected and unacceptable vegetation growth would be observed and correct as a matter of routine maintenance. Line of Sight: A two kilometer distance from the controlled area perimeter.</p>
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled "<a href="#">Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface</a>," the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight.</p>		
<p>Florida Reliability Coordinating Council</p>	<p>Negative</p>	<p>There is no technical justification for excluding 1 mile beyond the fence in the applicability of generators.</p>
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled "<a href="#">Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface</a>," the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight.</p>		
<p>Southern Company</p>	<p>No</p>	<p>â€¢All of these comments pertain to FAC-003-3:</p> <ol style="list-style-type: none"> <li>1) We suggest referring to the Implementation Plan in the Effective Date sub-section of Section A of the standard rather than repeating the content of the Implementation Plan in the standard. There exists unnecessary duplication with including the information in both places.</li> <li>2) We suggest simplifying the purpose statement to more succinctly say the intent, for example: "To maintain a reliable transmission system by managing vegetation</li> </ol>

Organization	Yes or No	Question 3 Comment
		<p>located on transmission rights of way to minimize vegetation encroachments and thereby minimize the risk of vegetation related outages". If this change is not acceptable, at least change the phrase "preventing the risk" to "minimizing the risk".</p> <p>3) We feel that the Enforcement paragraphs between 4.3.1.3 and 5.0 seem to be out of place. Those paragraphs don't belong in this location - consider moving them to Section C. Compliance. The fourth paragraph belongs in the background section.</p> <p>4) We suggest moving the background section to Section F. "Associated Documents". It gets in the way of getting to the requirements of the standard.</p> <p>5) We suggest moving Table 2 of the "Guideline and Technical Basis" document into R1, since it seems to be the only part of the document that is enforceable. Further we suggest that the Guideline and Technical Basis document be removed from the standard. The inclusion of this document in the standard makes the standard unwieldy.</p> <p>6) We suggest reordering the words in R1 to more clearly state the requirement. Please consider this rephrasing: "For lines which are either an element of an IROL or an element of a Major WECC Transfer Path, each applicable TO and applicable GO shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) when operating within their Rating during all Rated Electrical Operating Conditions of the types shown below:..." (remainder is unchanged).</p> <p>7) We suggest reordering the words of R2 to more clearly state the requirement. Please consider the this rephrasing: "For lines which are neither an element of an IROL nor an element of a Major WECC Transfer Path, each applicable TO and applicable GO shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) when operating within its Rating and during all Rated Electrical Operating Conditions of the types listed below:..." (remainder is unchanged).</p> <p>8) On Page 11 of the posted clean draft standard, is the reference to the previous footnote 2 correct? We recommend eliminating footnotes where possible to minimize redirections.</p>

Organization	Yes or No	Question 3 Comment
		9) The Rationale text-box on page 13 of the clean version of FAC-003-3 overlaps some of the text of footnote #6.   â€œ,â€œ,â€œ,
<p><b>Response:</b> Thank you for your comment.</p> <p>With respect to your suggestion regarding the implementation plan, the SDT simply followed the NERC-mandated document guidelines. Making the change you suggest would deviate from that process and thus the SDT has not made it.</p> <p>With respect to comments 2-8, any standard changes that go beyond making a standard applicable to a GO or GOP are beyond the scope of this SDT. Any redline changes the SDT has made within standards were made to clarify or qualify the GO or GOP applicability. These comments would have been more appropriate to make during the comment period for Project 2007-07 Vegetation Management, the project that revised the version of FAC-003 from which this SDT is working.</p> <p>We have modified the rationale box on page 13 so that it does not overlap with the text of footnote 6.</p>		
Dominion	No	<p>Dominion suggests in FAC-003-X; 4.3.1. Regional Entity be changed to RE as listed in 4.2.1 for consistency. Also Regional Entity is used throughout the rest of the document, suggest using RE for consistency overall. Dominion suggests in FAC-003-3; 4.3.1. adding station to the following “ Overhead transmission lines that extend greater than one mile or 1.609 kilometers beyond the fenced area of the generation station switchyard and are” to show consistency as it is written in FAC-003-X 4.3.1. Further, Dominion is concerned that the technical justification characterized the exclusion (i.e., one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard) as “approximate line of sign [sic] from a fixed point” and notes that this line of sight may be limited by local terrain. Where line of sight of the radial corridor is limited on a clear day due to terrain, the one mile exemption must be limited in distance to no more than the line of sight on a clear day beyond the fenced area.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees with your comment about the Regional Entity, but will instead use Regional Entity throughout.</p> <p>Thank you for your comment. As it discusses in the document titled <a href="#">“Technical Justification Project 2010-07 Generator Requirements at</a></p>		

Organization	Yes or No	Question 3 Comment
<p><a href="#">the Transmission Interface</a>,” the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight.</p>		
Exelon	No	<p>FAC-003 - Exelon supports the one mile length qualifier, but feels that additional clarification is needed to determine the points of demarcation. There are too many differing physical configurations to use a “fence line” as a determination of applicability. Suggest that the tie line length be defined as “from the Generator Step up Transformer GSU to the point of interconnection between the GO and TO owned equipment.” Also suggest that the standard define what constitutes a generation station switchyard.</p>
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled <a href="#">“Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface,”</a> the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight.</p>		
Ingleside Cogeneration LP (Occidental Chemical)	No	<p>Ingleside Cogeneration LP is very concerned that the attempt to develop “bright-line” criteria to assign applicability to either version of FAC-003 is misplaced. As seen with NERC’s recent proposed directive related to Generator-Transmission interconnections, those thresholds can be arbitrarily reduced based upon regulators aversion to risk - not scientific evidence. (As it stands today, NERC has proposed any interconnection facility operating at 100 kV or higher and greater than 3 spans in length be applicable - which is even stricter than the TO thresholds in FAC-003.)This would suggest that a reliability assessment consistent with the TPL standards must</p>

Organization	Yes or No	Question 3 Comment
		<p>be the determining factor. If the Planning Coordinator or Transmission Planner can show that the Generator-Transmission interconnection could contribute to a violation of an SOL or IROL, then a vegetation management program may be in order. Furthermore, there needs to be some level of common sense applied if a GO-TO interconnection is located in an area where vegetation clearance is never an issue. A one-size-fits-all requirement based upon vegetation growth in the sub-tropics, should not automatically apply in the desert. In our view, every dollar spent to control vegetation in an arid climate is one less dollar available to purchase advanced telemetry, AGC systems, and other items which have a far greater impact on reliability.</p>
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled <a href="#">“Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface,”</a> the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight.</p> <p>The SDT also took into consideration the stakeholder comments submitted and believes this exemption adequately addresses the reliability impact for a majority of the Facilities, while balancing the efforts necessary to support the standard from all entities.</p>		
Manitoba Hydro	No	<p>Manitoba Hydro does not support the changes being proposed in this project. If a Generator Owner is required to register as a TO, all the Requirements applicable to a TO should apply. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions.</p>
<p><b>Response:</b> Thank you for your comment. The scope of this SDT is addressed in the <a href="#">SAR</a>. The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT also refers the commenter to the document titled <a href="#">Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document</a>. Specifically, see the last paragraph on page 4 and first two on page 5.</p>		

Organization	Yes or No	Question 3 Comment
<p>Northeast Power Coordinating Council, Northeast Power Coordinating Council</p>	<p>No</p>	<p>Suggest in FAC-003-X; 4.3.1. that Regional Entity be changed to RE as listed in 4.2.1 for consistency. Also Regional Entity is used throughout the rest of the document, suggest using RE for consistency. In FAC-003-3; 4.3.1. add station to the following: “Overhead transmission lines that extend greater than one mile or 1.609 kilometers beyond the fenced area of the generation station switchyard and are” to show consistency as it is written in FAC-003-X 4.3.1. The technical justification characterized the exclusion (i.e., one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard) as “approximate line of sight [sic] from a fixed point” and noted that this line of sight may be limited by local terrain. Where line of sight of the radial corridor is limited on a clear day due to terrain, the one mile exemption must be limited in distance to no more than the line of sight on a clear day beyond the fenced area.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees with your comment about the Regional Entity, but will instead use Regional Entity throughout.</p> <p>Thank you for your comment. As it discusses in the document titled <a href="#">“Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface,”</a> the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight.</p>		
<p>MRO NSRF</p>	<p>No</p>	<p>The NSRF agrees with the drafting committees desire to eliminate arbitrary and capricious behavior of auditors and industry staff by precisely defining the point at which measurement starts for the length of transmission line. The concern the NSRF has with the proposed wording is that many generating station may not have a “generating station switchyard” as implied by the proposed wording. Often the generator leads (e.g. 20 kV) will exit the generator and connect to transformers located in transformer bays directly adjacent to the plant. From the transformers</p>



Organization	Yes or No	Question 3 Comment
		<p>the now greater than 200 kV lines will be routed to the point of interconnect or a generating unit switchyard, possibly miles or yards away. By no one’s definitions would the transformer bays adjacent to the plant be considered a switchyard. The plant fence may be yards or hundreds of yards from the bays and on a multiple unit site, there may be a site fence or boundary, which could be comprise of fences, security patrols, or other barriers yards or miles from the transformer but enveloping the switchyard. The valid assumption made by the drafting team is that transmission lines within an area tightly controlled by the generator operator poses very little risk to the BES as a result of vegetation contact. This assumption is based on the valid observation that these areas are routinely occupied and observed by station personnel and as a result unexpected and unacceptable vegetation growth is highly unlikely because it is controlled by routine maintenance. It also correctly assumes that some distance past the controlled area is acceptable since this area would also be under near continuous observation. The problem comes in defining both a tightly controlled area and a line of site. We suggest the following: Controlled Area: A perimeter around a power plant, power plants, or switchyard which is prevents intrusion by the use of physical barriers, observation, or electronic monitoring and is routinely occupied such that unexpected and unacceptable vegetation growth would be observed and correct as a matter of routine maintenance. Line of Sight: NSRF recommends a two kilometer distance from the controlled area perimeter. Our assessment is that an individual of average height would have a line of site of approximately 4 Kilometers. Therefore, we recommended a distance of 2 kilometers from the Controlled Area of the plant to provide margin. The revised applicability statement would read as follows: “Generator Owner that owns an overhead transmission line(s) that extends greater than 2.0 kilometers beyond the Controlled Area of the generating station up to the point of interconnection with a Transmission Owner’s Facility and is operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region. Furthermore we applaud the committee for using the metric system to identify the acceptable distance for this standard and urge it to remove all</p>

Organization	Yes or No	Question 3 Comment
		<p>references to English units. We strongly suggest this drafting team and all future drafting team abandon the anachronistic English measurement system. This archaic system, based on the length of an average barley corn, should be abandon in all scientific and engineering endeavors.</p>
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled "<a href="#">Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface</a>," the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight.</p>		
<p>Southwest Power Pool Standards Development Team</p>	<p>No</p>	<p>There is a possibility of some conflict with the Bulk Electric System Definition. This should be consistent with the Transmission Owner requirements if the lead is determined part of the BES.</p>
<p><b>Response:</b> Thank you for your comment. The SDT intended this standard to be applied to Facilities of GO and TO equally, with the exception of the distance exemption for a generator interconnection Facility. The SDT also notes that FAC-003-2 (approved by the NERC’s Board of Trustees on Nov. 3, 2011) does not rely upon the BES definition to determine the facility to which this standard applies (200 kV or higher, or IROL or WECC Transfer Path).</p>		
<p>South Carolina Electric and Gas</p>	<p>No</p>	<p>There should be no qualifying exemption to FAC-003 for Generator Owners.</p>
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled "<a href="#">Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface</a>," the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight.</p>		

Organization	Yes or No	Question 3 Comment
SERC Planning Standards Subcommittee	No	We believe there should be no exemption for Generator Owners.
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled <a href="#">“Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface,”</a> the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight.</p>		
PSEG	No	
Infigen Energy US	Affirmative	Infigen finds the DST supporting details regarding FAC-003-X to be appropriate. We support maintaining "reasonable and appropriate" risk prevention measures to minimize encroachment that could trigger vegetation-related outages.
<p><b>Response:</b> Thank you for your comment and support.</p>		
Seattle City Light	Affirmative	Key points are the greater than one mile with clear statement of “...beyond the fenced area of the generating switchyard.”
<p><b>Response:</b> Thank you for your comment and support.</p>		
RES Americas Development / American Wind Energy Association	Yes	Applying the vegetation management requirements to only generator lead lines that extend more than “one mile beyond the fenced area of the generating station switchyard” strikes a reasonable balance among the many stakeholder positions expressed on this topic. We think that as this criterion recognizes that there is little need for a vegetation management plan for shorter lines, it should explicitly state that this is true for all such facilities with lines of that length or smaller.
<p><b>Response:</b> Thank you for your comment and support.</p>		

Organization	Yes or No	Question 3 Comment
Texas Reliability Entity	Yes	In the description of the “second effective date” in FAC-003-X there is an erroneous reference to “Requirement R3,” which should be corrected to “Requirement R1.”
<b>Response:</b> Thank you for your comment and support. This conforming change was made.		
Seattle City Light	Yes	Key points are the greater than one mile with clear statement of “...beyond the fenced area of the generating switchyard.”
<b>Response:</b> Thank you for your comment and support.		
ACES Power Marketing Standards Collaborators	Yes	We support the changes to FAC-003 suggested by the drafting team because we believe the drafting team has provided the best solution in face of a difficult problem. However, in general, we do not support registration of GOs and GOPs as TOs and TOPs or applicability of any TO/TOP requirements to the GO/GOP simply because they have a radial interconnection greater than one mile in length. While there may be some generators that own interconnecting facilities of significant length operated at a significant voltage that could impact BES reliability, we do not believe that the number of generating facilities that fit into that category is significantly large. When one considers that the majority of generators are still owned and operator by utilities that are also registered as a TO and TOP, there is only a minority subset of generators left that could be considered. NERC has the registration for this remaining set of generators and could use the data to evaluate how many of this remaining subset have interconnections owned by the generator that are substantial enough to affect reliability. It seems that NERC could determine the boundaries of this problem before registering anymore GOs and GOPs as TOs and TOPs or before applying additional requirements through this effort on the GOs and GOPs.
<b>Response:</b> Thank you for your comment and support.		

Organization	Yes or No	Question 3 Comment
SERC OC Standards Review Group	Yes	
Southwest Power Pool Regional Entity	Yes	
Florida Municipal Power Agency	Yes	
PPL NERC Registered Affiliates	Yes	
Electric Power Supply Association	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
American Transmission Company	Yes	
Sempra Generation	Yes	

Organization	Yes or No	Question 3 Comment
Entergy Services	Yes	
Xcel Energy	Yes	
Cowlitz County PUD	Yes	
Constellation Power Source Generation	Yes	
Western Electricity Coordinating Council		
Puget Sound Energy, Inc.		
Compliance & Responsibility Organization		
Bonneville Power Administration		
Consolidated Edison Co. of NY, Inc.		
ReliabilityFirst		
Tennessee Valley Authority		

**4. Do you support compliance timeframe for Generator Owners as included and explained in the Implementation Plans for FAC-003-X?**

**Summary Consideration:**

The SDT thanks all stakeholders for their comments. The vast majority of stakeholders support the compliance timeframes as proposed and explained in the Implementation Plan for FAC-003-X.

One commenter found a typo in the effective dates section of FAC-003-X, where one section referenced R3 when it should have referenced R1. That has been corrected in both the standard and the Implementation Plan.

A few stakeholders thought that two years was too long for an Implementation Plan for this standard. The SDT reminded those commenters that the time frame was based on previous stakeholder comments and the fact that the Implementation Plan for Version 0 standards stated “the Version 0 Reliability Standards are generally a translation and clarification of existing operating policies and planning standards, entities that are in compliance with NERC policies and standards today are expected to be able to remain in compliance with the Version 0 Reliability Standards with their existing procedures, tools, and practices.” This process occurred over more than two years. It is therefore reasonable to assume that GOs, having never had to comply with a vegetation management standard, be afforded adequate time to do so.

Beyond the corrected typo, no changes were made.

Organization	Yes or No	Question 4 Comment
Ameren Services	Negative	The 2 year compliance time line is far too long. There is significant industry evidence that was developed in the drafting of Version 2 that supports a one year compliance time-line for new lines. This is evidenced in Version 2. Thus there is no basis for the 2 years.
<p><b>Response:</b> Thank you for your comment. The SDT choose the time in the implementation plan based upon comments of stakeholders and the fact that the implementation plan for <u>Version 0 standards</u> stated “the Version 0 Reliability Standards are generally a translation and clarification of existing operating policies and planning standards, entities that are in compliance with NERC policies</p>		

Organization	Yes or No	Question 4 Comment
<p>and standards today are expected to be able to remain in compliance with the Version 0 Reliability Standards with their existing procedures, tools, and practices.” This process occurred over more than two years. It is therefore reasonable to assume that GOs, having never had to comply with a vegetation management standard, be afforded adequate time to do so.</p>		
<p>Texas Reliability Entity</p>	<p>No</p>	<p>A compliance timeframe for the applicable GOs of two years is too long and the scenario used as a basis provides no timing specifics or details. Moreover, the 12 months for an existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard is arguably the same situation as an applicable GO but the applicable GO has an additional 12 months to come into compliance.</p>
<p><b>Response:</b> Thank you for your comment. The SDT choose the time in the implementation plan based upon comments of stakeholders and the fact that the implementation plan for <a href="#">Version 0 standards</a> stated “the Version 0 Reliability Standards are generally a translation and clarification of existing operating policies and planning standards, entities that are in compliance with NERC policies and standards today are expected to be able to remain in compliance with the Version 0 Reliability Standards with their existing procedures, tools, and practices.” This process occurred over more than two years. It is therefore reasonable to assume that GOs, having never had to comply with a vegetation management standard, be afforded adequate time to do so. The SDT does not believe that a TO’s acquisition of a new asset is the same as applying new requirements to a GO.</p>		
<p>Ingleside Cogeneration LP (Occidental Chemical)</p>	<p>No</p>	<p>Based upon similar issues addressed in Compliance Application Notices (CANs), the drafting team needs to specify when the first vegetation management inspection quarterly report, and any other requirement with an assigned interval in FAC-003-3 or FAC-003-X. Even if the decision is to adopt the same criteria proposed in CAN-0012, the industry is better served with a clear distinction made up front.</p>
<p><b>Response:</b> Thank you for your comment. This is a comment that is outside the scope of the SDT, and in fact deals with a larger body of standards than just FAC-003. No change made.</p>		
<p>PSEG</p>	<p>No</p>	<p>It’s no longer applicable.</p>
<p><b>Response:</b> Thank you for your comment. The SDT acknowledges that in November 2011, NERC’s Board of Trustees adopted FAC-003-2</p>		



Organization	Yes or No	Question 4 Comment
<p>– Transmission Vegetation Management (developed under Project 2007-07 Vegetation Management). Based on this approval, NERC staff will file FAC-003-2 with the applicable regulatory authorities. The Project 2010-07 SDT will move forward with ballots for both FAC-003-3 (proposed changes to the BOT-adopted FAC-003-2) and FAC-003-X (proposed changes to the FERC-approved FAC-003-1) with the intention of eventually only filing FAC-003-3. The SDT has elected to carry FAC-003-X through to ballot because if FAC-003-2 and FAC-003-3 are not approved by FERC, the SDT wants to be ready to file FAC-003-X to ensure that there is a functional entity responsible for managing vegetation on the piece of line commonly known as the generator interconnection Facility.</p> <p>Note that for its recirculation ballot, the SDT will be balloting <b>both</b> FAC-003-3 and FAC-003-X, but stakeholders should <b>not</b> vote as though they are choosing one or the other. As stated above, the SDT plans to present FAC-003-3 alone to NERC’s Board of Trustees, but it wants to have FAC-003-X ready to submit to the Board if, for some reason, neither FAC-003-2 nor FAC-003-3 are approved by FERC. Members of the ballot body should vote on the merits of each version of FAC-003 individually. <b>In other words, stakeholders who support adding GOs to the applicability of FAC-003 should vote in the affirmative for both FAC-003-3 and FAC-003-X.</b></p>		
Manitoba Hydro	No	See question 3 comments.
<p><b>Response:</b> See the SDT’s response to Question 3.</p>		
Southwest Power Pool Standards Development Team	No	The effective dates should be consistent with the original standard. If there is a reason for the extension we would like to know why.
<p><b>Response:</b> Thank you for your comment. The SDT choose the time in the implementation plan based upon comments of stakeholders and the fact that the implementation plan for <a href="#">Version 0 standards</a> stated “the Version 0 Reliability Standards are generally a translation and clarification of existing operating policies and planning standards, entities that are in compliance with NERC policies and standards today are expected to be able to remain in compliance with the Version 0 Reliability Standards with their existing procedures, tools, and practices.” This process occurred over more than two years. It is therefore reasonable to assume that GOs, having never had to comply with a vegetation management standard, be afforded adequate time to do so.</p>		
Southern Company	Yes	The development of a working TVMP will take some time to initialize. The 1 year time frame for R3 is appropriate. The 2 year time frame for all other requirements is appropriate.

Organization	Yes or No	Question 4 Comment
<b>Response:</b> Thank you for your comment and support.		
Seattle City Light	Yes	The explanation deals with the fact that there are simultaneous revisions of FAC-003 underway by two different teams.
<b>Response:</b> Thank you for your comment and support.		
MRO NSRF	Yes	There may be a typographical error on the effective date. As currently drafted the standard states: In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption. Should it be worded as follows? In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 R1 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.
<b>Response:</b> Thank you for your comment. The SDT agrees with you. "Requirement R3," will be corrected to "Requirement R1."		
RES Americas Development/ American Wind Energy Association	Yes	Yes, as with our comments to question 2, since there is no exigent reason why this standard needs to be put in place at once, we support the proposed compliance timeframe. We believe that it will allow generators a reasonable time to comply with the requirement.

Organization	Yes or No	Question 4 Comment
<b>Response:</b> Thank you for your comment and support.		
SERC OC Standards Review Group	Yes	
Northeast Power Coordinating Council, Northeast Power Coordinating Council	Yes	
Southwest Power Pool Regional Entity	Yes	
SERC Planning Standards Subcommittee	Yes	
Florida Municipal Power Agency	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Electric Power Supply Association	Yes	
American Electric Power	Yes	
BP Wind Energy North	Yes	

Organization	Yes or No	Question 4 Comment
America Inc.		
Exelon	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
American Transmission Company	Yes	
South Carolina Electric and Gas	Yes	
Sempra Generation	Yes	
Entergy Services	Yes	
Xcel Energy	Yes	
Cowlitz County PUD	Yes	
Constellation Power Source Generation	Yes	
Western Electricity Coordinating Council		

Organization	Yes or No	Question 4 Comment
Puget Sound Energy, Inc.		
Compliance & Responsibility Organization		
Bonneville Power Administration		
Consolidated Edison Co. of NY, Inc.		
ReliabilityFirst		
Tennessee Valley Authority		

5. In the FAC-003-3 implementation plan, the SDT has attempted to account for a number of different scenarios that could play out with respect to the filing and approvals of FAC-003-2 and FAC-003-3. Do you support this approach? If there are other scenarios that the SDT needs to account for, please suggest them here.

#### Summary Consideration:

The SDT thanks all stakeholders for their comments. The vast majority of stakeholders support the compliance timeframes as proposed and explained in the Implementation Plan for FAC-003-3.

One commenter thought that two years was too long for an Implementation Plan for this standard. The SDT reminded those commenters that the time frame was based on previous stakeholder comments and the fact that the Implementation Plan for Version 0 standards stated “the Version 0 Reliability Standards are generally a translation and clarification of existing operating policies and planning standards, entities that are in compliance with NERC policies and standards today are expected to be able to remain in compliance with the Version 0 Reliability Standards with their existing procedures, tools, and practices.” This process occurred over more than two years. It is therefore reasonable to assume that GOs, having never had to comply with a vegetation management standard, be afforded adequate time to do so.

Some stakeholders expressed confusion about the relationship between FAC-003-3 and the recently BOT-approved FAC-003-2. The SDT acknowledges that in November 2011, NERC’s Board of Trustees adopted FAC-003-2 – Transmission Vegetation Management (developed under Project 2007-07 Vegetation Management). Based on this approval, NERC staff will file FAC-003-2 with the applicable regulatory authorities. The Project 2010-07 SDT will move forward with ballots for both FAC-003-3 (proposed changes to the BOT-adopted FAC-003-2) and FAC-003-X (proposed changes to the FERC-approved FAC-003-1) with the intention of eventually only filing FAC-003-3. The SDT has elected to carry FAC-003-X through to ballot because if FAC-003-2 and FAC-003-3 are not approved by FERC, the SDT wants to be ready to file FAC-003-X to ensure that there is a functional entity responsible for managing vegetation on the piece of line commonly known as the generator interconnection Facility.

All stakeholders should note that for its recirculation ballot, the SDT will be balloting **both** FAC-003-3 and FAC-003-X, but stakeholders should **not** vote as though they are choosing one or the other. As stated above, the SDT plans to present FAC-003-3 alone to NERC’s Board of Trustees, but it wants to have FAC-003-X ready to submit to the Board if, for some reason, neither FAC-003-2 nor FAC-003-3 are approved by FERC. Members of the ballot body should vote on the merits of each version of FAC-003 individually. **In other words, stakeholders who support adding GOs to the applicability of FAC-003 should vote in the affirmative for both FAC-003-3 and FAC-003-X.**

Organization	Yes or No	Question 5 Comment
Manitoba Hydro	No	See question 3 comments.
<b>Response:</b> See the SDT’s response to Question 3.		
Southern Company	No	We believe that a standard development process should not have parallel paths where the same version is being modified by multiple teams. The uncertainty in which development path leads to confusion in the industry and ultimately proves to have wasted some resources for the path that does not come to fruition.
<p><b>Response:</b> Thank you for your comment. While the SDT agrees this is not preferable, it was necessary given the urgency of both projects. The SDT did the best it could to describe the scenarios and reasons for posting multiple versions.</p> <p>In November 2011, NERC’s Board of Trustees adopted FAC-003-2 – Transmission Vegetation Management (developed under Project 2007-07 Vegetation Management). Based on this approval, NERC staff will file FAC-003-2 with the applicable regulatory authorities. The Project 2010-07 SDT will move forward with ballots for both FAC-003-3 (proposed changes to the BOT-adopted FAC-003-2) and FAC-003-X (proposed changes to the FERC-approved FAC-003-1) with the intention of eventually only filing FAC-003-3. The SDT has elected to carry FAC-003-X through to ballot because if FAC-003-2 and FAC-003-3 are not approved by FERC, the SDT wants to be ready to file FAC-003-X to ensure that there is a functional entity responsible for managing vegetation on the piece of line commonly known as the generator interconnection Facility.</p>		
Ingleside Cogeneration LP (Occidental Chemical)	Yes	Ingleside Cogeneration agrees that the SDT’s approach is thorough. We are far more concerned about FAC-003’s applicability criteria and implementation time frame at this point - as stated in our responses to questions 3 and 4.
<b>Response:</b> Thank you for your comment and support. Please refer to the SDT’s responses to Questions 3 and 4.		
ACES Power Marketing Standards Collaborators	Yes	With recent NERC BOT approval of the FAC-003-2 standard, the drafting team should continue to monitor the standard progress with FERC and make necessary adjustments to the implementation plan.
<b>Response:</b> Thank you for your comment. The SDT acknowledges that FAC-003-2 was recently approved by the BOT. The SDT does not		

Organization	Yes or No	Question 5 Comment
<p>see the need to revise the GO implementation plan, as it already accounts for a number of scenarios that could occur based on how FERC handles the filing of FAC-003-2.</p>		
<p>Ameren</p>		<p>(a) There is no technical basis for the one mile length exemption. In fact, one could argue that a very short line, 300 feet in length, that experienced a fault from a tree at "the end of the circuit", i.e near the switchyard fence, would have much more of an impact on the BES because the fault would be limited by much less impedance.</p> <p>(b) It is also unclear in this version if a GO that owned one line that was 1.2 miles in length would have to comply for the entire length of said line, or just 0.2 miles of said line. If the GO is responsible for 1.2 miles, then that argues that the first mile is important and consequently there is no basis for ignoring the first mile on other lines. If the GO is only responsible for 0.2 miles, what is the technical basis to ignore a mile? And would it be the first mile from the switchyard that is ignored, or is the middle mile, or the last mile where it connects to the TO? Or could the GO decide? Or could the GO pick sections of the line that amount to a mile that they can ignore? This seems like something that should be addressed for compliance.</p> <p>(c) The 2 year compliance time line is far too long. There is significant industry evidence that was developed in the drafting of Version 2 that supports a one year compliance time-line for new lines. This is evidenced in Version 2. Thus there is no basis for the 2 years</p>
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled "<a href="#">Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface</a>," the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight.</p> <p>With respect to your second comment, the SDT intended for the length qualifier to be just that; if the overhead portion of a Facility exceeds the distance, <u>the entire Facility</u> is subject to the requirements of the standard.</p>		



Organization	Yes or No	Question 5 Comment
<p>The SDT choose the time in the implementation plan based upon reasons it documented in the <a href="#">accompanying implementation plan</a> and also based upon comments of stakeholders.</p>		
PSEG	Yes	
SERC OC Standards Review Group	Yes	
Southwest Power Pool Standards Development Team	Yes	
Northeast Power Coordinating Council, Northeast Power Coordinating Council	Yes	
MRO NSRF	Yes	
SERC Planning Standards Subcommittee	Yes	
Florida Municipal Power Agency	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
Electric Power Supply Association	Yes	
American Wind Energy	Yes	

Organization	Yes or No	Question 5 Comment
Association		
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Exelon	Yes	
Seattle City Light	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
American Transmission Company	Yes	
South Carolina Electric and Gas	Yes	
RES Americas Development	Yes	
Sempra Generation	Yes	
Entergy Services	Yes	

Organization	Yes or No	Question 5 Comment
Xcel Energy	Yes	
Cowlitz County PUD	Yes	
Texas Reliability Entity	Yes	
Constellation Power Source Generation	Yes	
Tennessee Valley Authority	Yes	
Southwest Power Pool Regional Entity		
Western Electricity Coordinating Council		
Puget Sound Energy, Inc.		
Compliance & Responsibility Organization		
Bonneville Power Administration		
Consolidated Edison Co. of NY, Inc.		
ReliabilityFirst		

6. In its technical justification document, the SDT reviews all standards that had been proposed for substantive modification in the Ad Hoc Group’s original support and explains why, with the exception of FAC-003, modifying them would not provide any reliability benefit. Do you support these justifications? If you believe the SDT needs to add more information to its rationale for any of these decisions, please include suggested language here.

**Summary Consideration:**

The SDT thanks all stakeholders for their comments.

A few commenters pointed out that the wording in R1 and R2 of PRC-005-1a requires the same explicit reference to a generator interconnection Facility that was added in PRC-004-2a R2. The SDT is developing revisions to PRC-005-1a and will post them soon.

Many commenters encouraged the SDT to reexamine the standards and requirements that FERC and NERC applied to GOs and GOPs in their Milford/Cedar Creek order and draft compliance directive regarding generator leads. The SDT pointed out that the NERC Standard Processes Manual does not address the issue of how to deal with FERC Orders (that don’t include explicit directives), or NERC directives, within the standards process, and until this round of comments, when NERC staff submitted comments, the SDT had no formal mandate that would have made it appropriate to consider the content of the proposed directive.

Based on stakeholder comments, the SDT expanded its technical justification document (posted under “Supporting Materials”) to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.

One commenter remains concerned about the scope of the SDT. The SDT reminded this commenter that its scope is addressed in the SAR and that its intent is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT also refers the commenter to the document titled Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document. Specifically, see the last paragraph on page 4 and first two on page 5.

Organization	Yes or No	Question 6 Comment
Manitoba Hydro	Negative	The intention of the NERC SDT in revising these standards is not clear. While the Technical Justification document states that the SDT intended to focus on a Generator

Organization	Yes or No	Question 6 Comment
		<p>Owner’s radial interconnection facilities, the scope of the revised standard (s) is not confined to such facilities. The very broadly defined term “Facility” is used. Moreover, the Technical Justification document’s reference to the FERC decision in Cedar Creek as a basis for the revision of additional standards is confusing, since that decision did not specifically address the issue of radial facilities and supported NERC’s registration of GOs as TOs.</p>
<p><b>Response:</b> Thank you for your comment. The scope of this SDT is addressed in the <a href="#">SAR</a>. The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT determined that it should first address “low-hanging fruit” and believes these to be sole-use Facilities (see posted examples under “Supporting Materials”) – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP). Through our deliberations, we came to the conclusion that an interconnection Facility owned or operated by a GO or GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT.</p> <p>The SDT also refers the commenter to the document titled <a href="#">Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document</a>. Specifically, see the last paragraph on page 4 and first two on page 5.</p>		
Texas Reliability Entity	No	<p>Our negative votes on FAC-003 reflect our concern that this project has not considered all of the applicable standards. Why did the SDT choose to only review the Ad Hoc Group’s standards when there have been multiple registration appeals in which FERC and NERC have repeatedly cited specific additional TO/TOP standards that were determined to be applicable to GO/GOPs? This SDT project would serve a tremendous value to the ERO and in particular industry if it were to address the technical aspects of the following FERC ordered applicable standards: PRC-001-1 R2, R4; PRC-004-1 R1; TOP-004-2 R6; PER-003-1 R1; FAC-003-1 R1, R2; TOP-001-1a R1 and FAC-004-2 R2. The SDT team should analyze the FERC orders, the applicable standards indicated, and the circumstances and facts involved, and technically justify why no reliability gap exists if these standards are not applied to GO interface facilities. The SDT should include more “technical” information in its technical justification document. For example, in regards to TOP-004-2 R7, the SDT technical</p>

Organization	Yes or No	Question 6 Comment
		<p>justification states that there is no reliability gap because, “. . . because an operator has a fiduciary obligation to protect a Facility for which it is operationally responsible.” An entity having a fiduciary obligation is not a technical justification of why a reliability gap does not exist. Moreover, by that logic there would be no need for many standards because every registered entity has a fiduciary obligation to protect its facilities.</p>
<p><b>Response:</b> Thank you for your comment. The NERC <a href="#">Standard Processes Manual</a> does not address the issue of how to deal with FERC Orders (that don’t include explicit directives), or NERC directives, within the standards process, and until this round of comments, when NERC staff submitted comments, the SDT had no formal mandate that would have made it appropriate to consider the content of the directive you reference.</p> <p>We would like to clarify, in response to the comment concerning TOP-004-2 R7, that in the document titled “<a href="#">Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface</a>” the SDT also stated “FAC-008-1—Facility Ratings Methodology and FAC-009-1—Establish and Communicate Facility Ratings already infer that the reason for establishing a ratings methodology and communicating facility ratings to the Reliability Coordinator, Planning Authority, Transmission Planner, and Transmission Operator is for use in reliable planning and operation of the Bulk Electric System.”</p> <p>Based on your and other comments, we have expanded our technical justification document (posted under “Supporting Materials”) to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.</p>		
PSEG	No	<p>PRC-005-1 - Transmission and Generation Protection System Maintenance and Testing was recommended by the Ad Hoc Group for modification, but not addressed to the technical justification document. It should be.</p>
<p><b>Response:</b> Thank you for your comment. We have reviewed PRC-005-1a and believe that the wording in R1 and R2 of that standard require the same explicit reference to a generator interconnection Facility that was added in PRC-004-2a R2. The SDT is developing revisions to PRC-005-1a and will post them soon.</p>		
Florida Municipal Power	No	see comment to Question 7

Organization	Yes or No	Question 6 Comment
Agency		
<b>Response:</b> See the SDT’s response to Question 7.		
Manitoba Hydro	No	See Question 7 comments.
<b>Response:</b> See the SDT’s response to Question 7.		
MRO NSRF	No	The NSRF has one concern with the current justification and definitions. At some point, if enough interconnections are made to generator outlet leads in accordance with FAC-001, the original generator operator will be a Transmission Operator and a Transmission Owner. This point in time needs to be explicitly defined by the drafting team.
<b>Response:</b> The SDT cannot act on this comment. Registration is outside the scope of this SDT and resides with NERC and the Regional Entity.		
Manitoba Hydro		If the drafting team intends to limit the scope of FAC-001-1 to GO owned radial generator interconnection facilities that are not deemed BES transmission and therefore would not require the registration of the GO as a TO, Manitoba Hydro disagrees with the proposed changes to FAC-001-1 as Generator Owners may not have the models or expertise to perform interconnection studies to determine if there is an impact on the Transmission Network. This concern is echoed in the technical justification document provided by NERC: ‘the SDT acknowledges that the Generator Owner may not, at the time it agrees or is compelled to allow a third part to interconnect, have the necessary expertise to conduct the required interconnect studies to meet this standard... the Generator Owner will have to acquire such expertise. How the Generator Owner chooses to do so is not for the SDT to determine.’ Although it may not be for the SDT to determine how a GO obtains technical expertise, ensuring that such expertise is acquired before a GO conducts the required interconnection studies should be a concern to NERC as this directly affects

Organization	Yes or No	Question 6 Comment
		<p>the reliability of the BES. As a result, all interconnection requests should be implemented by the TO providing the GO with connection to the BES regardless if the interconnection point is within a Generation Owner facility or End-User facility as the TO is in the best position to set unbiased connection requirements to ensure the reliability of the BES is maintained. If the scope of FAC-001-1 also applies to GO owned BES transmission facilities, Manitoba Hydro strongly believes that the Compliance Registry should apply and the GOs should be required to register as a TO and abide by all applicable standards to that functional type. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. Reliability gaps would be better addressed if select GOs and GOPs registered as TOs and TOPs to ensure all reliability standards, including the protection standards, are met so the reliability of the BES is maintained. At this time, this would not lead to a large number of extra registrations since, as stated in the technical justification document, ‘interconnection requests for Generator Owner Facilities are still relatively rare.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees this is a complex issue and did its best to outline how it arrived at its position in the document titled <a href="#">“Technical Justification: FAC-001-1.”</a></p> <p>The SDT points out that if the GO is part of an RTO, then the GO will be coordinating any interconnection studies either directly or indirectly with the RTO interconnection process. If the GO is not part of an RTO, then the GO will be required to follow the pro forma interconnection procedures from Order 2003. The Order 2003 procedures require the GO to coordinate any studies with an affected system which could include Facilities owned by one, or more, TO on the other side of the GO’s existing point of interconnection.</p> <p>The SDT has proposed the modification of a select set of standards so that they apply to GOs and GOPs as an alternative to registering all GOs and GOPs as TOs and TOPs. The SDT does agree that upon interconnection of a third party, other standards or registrations may apply as appropriate.</p>		
Electric Power Supply Association	Affirmative	All TO requirements for FAC-001-1 would apply if and when GO executes an Agreement to evaluate the reliability impact of interconnecting a third party Facility to its existing generation interconnection Facility. The execution of the agreement is necessary to comply with FAC-002-1 and start the compliance clock with the



Organization	Yes or No	Question 6 Comment
		<p>applicable regulatory authority. Thus as the Project 2010-07 Standard Drafting Team (SDT) in its technical justification has stated, “If, and only if, the existing owner of a generator interconnection Facility has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to its existing generation Facility” then FAC-001-1 should apply. EPSA concurs with SDT’s conclusion. The SDT has examined the issue regarding if future requests for transmission service on the interconnection Facility and in doing so acknowledged that when that Facility adopted open access and was providing transmission service it would necessitate re-evaluation of the need for the Facility to be maintained in accordance with FAC-001-1, Requirements 2 and 4. This service would indeed prompt the necessary agreement the SDT contemplates in its technical justification of FAC-001-1. EPSA believes this serves as the necessary trigger for evaluation of Requirements 2 and 4 under FAC-001-1 for GOs.</p>
<p><b>Response:</b> Thank you for your comment and support.</p>		
<p>Infigen Energy US</p>	<p>Affirmative</p>	<p>Infigen supports the FAC-001-1 technical analysis by the Project 2010-07 SDT, which states in part that “If, and only if, the existing owner of a generator interconnection Facility has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to its existing generation Facility would the proposed FAC-001-1 apply”. We agree with the SDT’s reasoning that if the owner of the existing generator interconnection Facility agrees, or is compelled to allow a third party to interconnect, but can do so using existing agreements, contracts, and/or tariffs [to avoid requiring additional executed Agreement(s)], this is the most prudent and effective way to manage this process with continuity. In order to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility more expediently, it can avoid having to develop its own connection requirements or perform additional impact studies, to the extent possible. We find it reasonable to negotiate with the existing Transmission Owner, Transmission Planner, and/or Transmission Service Provider to manage this requirement, utilizing their</p>

Organization	Yes or No	Question 6 Comment
		existing processes and Agreements for the purpose of fulfilling FAC-001-1.
<p><b>Response:</b> Thank you for your comment and support.</p>		
Southern Company	Yes	Additional responses are needed to justify the exclusion of the list of requirements and standards found in the recent FERC order denying the rehearing request of the Compliance Registry Appeals of Cedar Creek and Milford. (135 FERC Para. 61,241). Please see our response to Question 10 for a detailed discussion on this topic.â€,â€,â€,
<p><b>Response:</b> Thank you for your comment. The NERC <a href="#">Standard Processes Manual</a> does not address the issue of how to deal with FERC Orders (that don't include explicit directives), or NERC directives, within the standards process, and until this round of comments, when NERC staff submitted comments, the SDT had no formal mandate that would have made it appropriate to consider the content of the directive you reference.</p> <p>Based on your and other comments, we have expanded our technical justification document (posted under "Supporting Materials") to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.</p>		
Constellation Power Source Generation	Yes	Constellation supports the SDT justifications and offers additional information in our response to question 10.
<p><b>Response:</b> Thank you for your comment and support.</p>		
Ingleside Cogeneration LP (Occidental Chemical)	Yes	Ingleside Cogeneration LP believes the SDT has spent a significant amount of time and effort to demonstrate that only FAC-001, FAC-003, and PRC-004 need to be modified to address any reliability gaps that may exist related to the GO-TO interconnection. We agree that the other standards/requirements identified by the Ad Hoc Group are covered elsewhere.
<p><b>Response:</b> Thank you for your comment and support.</p>		

Organization	Yes or No	Question 6 Comment
American Wind Energy Association	Yes	The reasoning of the SDT is comprehensive and makes a strong case for why there is no need for additional standards to be applied to GO/GOP lead lines as they will not improve the reliability of the Bulk Electric System. In fact, as noted above, such additional standards may decrease reliability by diverting the GO/GOP's resources from the operation of the equipment that actually produces electricity - the generation equipment itself.
<b>Response:</b> Thank you for your comment and support.		
RES Americas Development	Yes	The reasoning of the SDT is comprehensive and makes a strong case for why there is no need for additional standards to be applied to GO/GOP lead lines as they will not improve the reliability of the Bulk Electric System. In fact, as noted above, such additional standards may decrease reliability by diverting the GO/GOP's resources from the operation of the equipment that actually produces electricity - the generation equipment itself.
<b>Response:</b> Thank you for your comment and support.		
SERC OC Standards Review Group	Yes	
Southwest Power Pool Standards Development Team	Yes	
Northeast Power Coordinating Council, Northeast Power Coordinating Council	Yes	
Southwest Power Pool Regional Entity	Yes	

Organization	Yes or No	Question 6 Comment
SERC Planning Standards Subcommittee	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Electric Power Supply Association	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Exelon	Yes	
Seattle City Light	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
American Transmission Company	Yes	
South Carolina Electric and	Yes	

Organization	Yes or No	Question 6 Comment
Gas		
Sempra Generation	Yes	
Xcel Energy	Yes	
Cowlitz County PUD	Yes	
Western Electricity Coordinating Council		
Puget Sound Energy, Inc.		
Compliance & Responsibility Organization		
Bonneville Power Administration		
Independent Electricity System Operator		
Ameren		
Consolidated Edison Co. of NY, Inc.		
Entergy Services		
ReliabilityFirst		

Organization	Yes or No	Question 6 Comment
Tennessee Valley Authority		

**7. The SDT is attempting to modify a set of standards so that radial generator interconnection Facilities are appropriately accounted for in NERC's Reliability Standards, both to close reliability gaps and to prevent the unnecessary registration of GOs and GOPs at TOs and TOPs. Does the set of standards currently posted achieve this goal?**

**Summary Consideration:**

The SDT thanks all stakeholders for their comments. Most commenters support the SDT's work and agree that the set of standards for which the SDT has proposed modification ensure that radial generator interconnection Facilities are appropriately accounted for in NERC's Reliability Standards.

One commenter continues to express confusion about the scope of the SDT's work in general. The SDT reminded this commenter that its scope is addressed in the [SAR](#). The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT determined that it should first address "low-hanging fruit" and believes these to be sole-use Facilities (see posted examples under "Supporting Materials") – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP). Through its deliberations, the SDT came to the conclusion that an interconnection Facility owned or operated by a GO or GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT. The SDT also refers the commenter to the document titled [Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document](#) (specifically, the last paragraph on page 4 and first two on page 5). The SDT has proposed the modification of a select set of standards so that they apply to GOs and GOPs as an alternative to registering all GOs and GOPs as TOs and TOPs, a strategy that has been widely supported by the stakeholder body. The SDT does agree that upon interconnection of a third party, other standards or registrations may apply as appropriate.

One commenter asked the SDT to specify what it means by "radial." By "radial generator interconnection Facilities," the SDT means sole-use Facilities (see posted examples under "Supporting Materials") – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP).

A few commenters suggested that the SDT address those standards cited by FERC and NERC in related projects. The SDT pointed out that the NERC [Standard Processes Manual](#) does not address the issue of how to deal with FERC Orders (that don't include explicit directives), or NERC directives, within the standards process. However, based on stakeholder comments, the SDT has expanded its technical justification document (posted under "Supporting Materials") to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.

One commenter suggested that the SDT include the GO in TOP-004-2 R6, but the SDT continues to maintain that no gap exists because TOP-002-2 R3 already requires the GO to coordinate with its host BA and TSP, who in turn are required to coordinate with their TOPs.

One commenter pointed out that the Data Retention section of the proposed PRC-004-2.1a also requires modification to include the generator interconnection Facility. The SDT agrees and made this change.

Organization	Yes or No	Question 7 Comment
Manitoba Hydro	Negative	<p>Manitoba Hydro has the following comments:</p> <p>1) The intention of the NERC SDT in revising these standards is not clear. While the Technical Justification document states that the SDT intended to focus on a Generator Owner’s radial interconnection facilities, the scope of the revised standard (s) is not confined to such facilities. The very broadly defined term “Facility” is used. Moreover, the Technical Justification document’s reference to the FERC decision in Cedar Creek as a basis for the revision of additional standards is confusing, since that decision did not specifically address the issue of radial facilities and supported NERC’s registration of GOs as TOs.</p> <p>2) Manitoba Hydro strongly disagrees with bypassing the NERC Compliance Registry and only having a limited set of standards apply to the GOs ‘interconnection facilities’ If a Generator Owner wants to own transmission facilities and it falls under the definition of a Transmission Owner under the NERC Registry Criteria, then all the Requirements applicable to a TO should apply. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. Reliability gaps would be better closed if select GOs and GOPs simply registered as TOs and TOPs. At this time, this would not lead to a large number of extra registrations since, as stated in the technical justification document, ‘interconnection requests for Generator Owner Facilities are still relatively rare.</p>
<p><b>Response:</b> Thank you for your comment. The scope of this SDT is addressed in the <a href="#">SAR</a>. The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT determined that it should first address “low-hanging fruit” and believes these to be sole-use Facilities (see posted examples under</p>		



Organization	Yes or No	Question 7 Comment
<p>“Supporting Materials”) – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP). Through our deliberations, we came to the conclusion that an interconnection Facility owned or operated by a GO or GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT.</p> <p>The SDT also refers the commenter to the document titled <a href="#">Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document</a>. Specifically, see the last paragraph on page 4 and first two on page 5.</p> <p>The SDT has proposed the modification of a select set of standards so that they apply to GOs and GOPs as an alternative to registering all GOs and GOPs as TOs and TOPs, a strategy that has been widely supported by the stakeholder body. The SDT does agree that upon interconnection of a third party, other standards or registrations may apply as appropriate.</p>		
Manitoba Hydro	Negative	<p>Manitoba Hydro strongly disagrees with bypassing the NERC Compliance Registry and only having a limited set of standards apply to the GOs ‘interconnection facilities’ If a Generator Owner wants to own transmission facilities and it falls under the definition of a Transmission Owner under the NERC Registry Criteria, then all the Requirements applicable to a TO should apply. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. Reliability gaps would be better closed if select GOs and GOPs simply registered as TOs and TOPs. At this time, this would not lead to a large number of extra registrations since, as stated in the technical justification document, ‘interconnection requests for Generator Owner Facilities are still relatively rare.</p>
<p><b>Response:</b> Thank you for your comment. The SDT has proposed the modification of a select set of standards so that they apply to GOs and GOPs as an alternative to registering all GOs and GOPs as TOs and TOPs, a strategy that has been widely supported by the stakeholder body. The SDT does agree that upon interconnection of a third party, other standards or registrations may apply as appropriate.</p>		
PSEG	No	<p>It would be helpful if the SDT defined what it means by the term “radial generator interconnection Facilities.” Does it mean interconnection Facilities that under Normal Clearing for a fault do not interrupt flows on other BES Elements? This is also confusing because of the radial exclusion included in the BES definition work in</p>

Organization	Yes or No	Question 7 Comment
		Project 2010-17. That definition would allow part of a three-terminal circuit to be excluded from the BES, while the other parts are included in the BES.
<p><b>Response:</b> Thank you for your comment. By “radial generator interconnection Facilities,” the SDT means sole-use Facilities (see posted examples under “Supporting Materials”) – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP). Through our deliberations, we came to the conclusion that an interconnection Facility owned or operated by a GO/GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT.</p>		
Texas Reliability Entity	No	See comment 6.
<p><b>Response:</b> See the SDT’s response to Question 6.</p>		
Manitoba Hydro	No	<p>The SDT’s proposed modifications gives special treatment to the Generator Owner in that it allows the Generator Owner TO status for a couple of standards (FAC-001, FAC-003 and PRC-004), but exempts the Generator Owner from many of the standards applicable to a TO. The NERC Registry Criteria defines the various functional entities. If a Generator Owner wants to own transmission facilities and it falls under the definition of a Transmission Owner under the NERC Registry Criteria, then all the Requirements applicable to a TO should apply. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. Reliability gaps would be better closed if select GOs and GOPs simply registered as TOs and TOPs. At this time, this would not lead to a large number of extra registrations since, as stated in the technical justification document, ‘interconnection requests for Generator Owner Facilities are still relatively rare.</p>
<p><b>Response:</b> Thank you for your comment. The scope of this SDT is addressed in the <a href="#">SAR</a>. The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT determined that it should first address “low-hanging fruit” and believes these to be sole-use Facilities (see posted examples under “Supporting Materials”) – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP). Through our deliberations, we came to the conclusion that an interconnection Facility owned or operated by a GO or</p>		

Organization	Yes or No	Question 7 Comment
<p>GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT.</p> <p>The SDT also refers the commenter to the document titled <a href="#">Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document</a>. Specifically, see the last paragraph on page 4 and first two on page 5.</p> <p>The SDT has proposed the modification of a select set of standards so that they apply to GOs and GOPs as an alternative to registering all GOs and GOPs as TOs and TOPs, a strategy that has been widely supported by the stakeholder body. The SDT does agree that upon interconnection of a third party, other standards or registrations may apply as appropriate.</p>		
<p>Southwest Power Pool Regional Entity</p>	<p>No</p>	<p>The Technical Justification document did not review the standards FERC identified in paragraphs 71 and 87 of 135 FERC ¶ 61,241 ORDER DENYING APPEALS OF ELECTRIC RELIABILITY ORGANIZATION REGISTRATION DETERMINATIONS. The SDT needs to review these standards to determine if changes are needed; otherwise, FERC will require registration of GOs and GOPs as TOs and TOPs to address reliability gaps. If the SDT determines no changes are needed to these FERC-identified standards, they should provide justification.</p>
<p><b>Response:</b> Thank you for your comment. The NERC <a href="#">Standard Processes Manual</a> does not address the issue of how to deal with FERC Orders (that don't include explicit directives) within the standards process. However, based on your and other comments, we have expanded our technical justification document (posted under "Supporting Materials") to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.</p>		
<p>Southern Company</p>	<p>No</p>	<p>We don't believe the effort realizes the goal because 1) it is inclusive of FAC-001 that does not need any modifications and 2) the effort needs to reinforce the appropriate justification not to include the additional standards FERC has identified in their Cedar Creek and Milford Orders.</p>
<p><b>Response:</b> The SDT thanks you for your comment. The SDT believes that comment (1) is a complex issue and did its best to outline how it arrived at its position in the document titled "<a href="#">Technical Justification: FAC-001-1.</a>"</p>		

Organization	Yes or No	Question 7 Comment
		<p>As for comment (2), the NERC <a href="#">Standard Processes Manual</a> does not address the issue of how to deal with FERC Orders (that don't include explicit directives) within the standards process. However, based on your and other comments, we have expanded our technical justification document (posted under "Supporting Materials") to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.</p>
<p>Western Electricity Coordinating Council</p>	<p>No</p>	<p>WECC casts an affirmative vote for the SDT proposal as a necessary but not sufficient step in addressing the GOTO matter. WECC, NERC, and the other Regions developed a subset of Standards and Requirements that were considered necessary to address potential gaps for transmission interconnection facilities and operations to be included in a proposed NERC Directive, which is expected to issue by year-end. The subset of requirements developed for the proposed NERC Directive were informed by the applicable FERC Orders. Consequently, it is important that the SDT address the comparative reliability risks between the proposed NERC Directive List and the SDT Proposal to assure that reliability gaps will not result from the SDT proposal. Please see NERC's proposed Directive for the rationale and technical justification.</p>
<p><b>Response:</b> Thank you for your comment. The NERC <a href="#">Standard Processes Manual</a> does not address the issue of how to deal with FERC Orders (that don't include explicit directives), or NERC directives, within the standards process, and until this round of comments, when NERC staff submitted comments, the SDT had no formal mandate that would have made it appropriate to consider the content of the directive you reference.</p> <p>However, based on your and other comments, we have expanded our technical justification document (posted under "Supporting Materials") to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.</p>		
<p>Florida Municipal Power Agency</p>		<p>FMPA believes that TOP-004-2 R6.2 ought to also be addressed in the standards as applicable to GOPs. The requirements reads:R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and</p>

Organization	Yes or No	Question 7 Comment
		<p>implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: R6.2. Switching transmission elements. Although planned outages are covered in other standards applicable to a GOP, switching to close / synchronize a generator back to the system is not specifically covered in the standards. Some have argued that TOP-002-2 R3 causes GOPs to coordinate its current day plans with the TOP; however, the name of the standard is “Transmission Operations Planning” and therefore implies the availability of the generator and related equipment and not necessary implies the policies and procedures for switching operations; which includes synchronization. FMPA cannot imagine a generator that would not have such switching / synchronization policies and procedures coordinated with its interconnecting TOP; as such would normally be required through a Large Generator Interconnection Agreement through a pro forma OATT; however, FMPA is not aware of any instance in the standards that covers this. As such, FMPA recommends including TOP-004-2 R6.2 as being applicable to a GOP.</p>
<p><b>Response:</b> Thank you for your comment. We don’t agree that the gap exists because TOP-002-2 R3 already requires the GO to coordinate with its host BA and TSP, who in turn are required to coordinate with their TOPs.</p>		
Manitoba Hydro		<p>If the redline changes are implemented, GOs are removed from R4, thereby removing the obligation for GOs to maintain their connection requirements. If GOs are included in FAC-001, they should be held accountable to the same level as TOs and should be required to maintain their connection requirements. Requiring a GO to maintain connection requirements would be especially beneficial to the GO themselves. In the majority of instances, any GO that is an Applicable Entity for FAC-001 would initially be inexperienced in performing interconnection studies and would benefit from regular and frequent review of their connection requirements as experience and expertise are gained.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees this is a complex issue and did its best to outline how it arrived at its position</p>		

Organization	Yes or No	Question 7 Comment
in the document titled " <a href="#">Technical Justification: FAC-001-1.</a> "		
SERC OC Standards Review Group		Please list the set of standards are you referencing.
<b>Response:</b> The SDT is referring to those standards posted for comment (FAC-001-1, FAC-003-X, FAC-003-3, and PRC-004-2.1).		
Constellation Power Source Generation, Inc.	Affirmative	Constellation appreciates and supports the work of the standard drafting team. We recognize the significant time invested by technical experts from industry to consider the appropriate application of reliability standards to address concerns raised about coverage of transmission at the generator interface. The drafting team analysis identified the standards in need of revision to appropriately address the reliability concerns raised. Please see more detailed comments submitted in the Project 2010-07 comment form submitted on November 18, 2011.
<b>Response:</b> Thank you for your comment and support.		
Infigen Energy US	Affirmative	Infigen finds the SDT supporting measures and analysis regarding FAC-003-3 to be appropriate, and believes that it is prudent for Generation Owners and Transmission Owners to manage vegetation maintenance records/inspections accordingly. We support maintaining "reasonable and appropriate" risk prevention measures to minimize encroachment that could trigger vegetation-related outages.
<b>Response:</b> Thank you for your comment and support.		
PPL EnergyPlus LLC	Affirmative	PPL Generation, LLC, on behalf of its NERC-registered subsidiaries, appreciates the effort by the Standard Development Team to address the GO-TO interface issues in a manner that enhances the reliability of the BES without adding unnecessary burden on Generators. As registered GOs/GOPs, the PPL Generation registered entities agree with the changes made by the SDT to these three standards. To the extent that GOs/GOPs are required to register as TOs/TOPs, PPL Generation would have

Organization	Yes or No	Question 7 Comment
		significant concerns with meeting the compliance requirements applicable to TOs in the standards included in the scope of this Project, as well as other TO/TOP requirements throughout other NERC standards.
<p><b>Response:</b> Thank you for your comment and support.</p>		
Puget Sound Energy, Inc.	Affirmative	The changes to this standard are minor, and seem to be centered around including "generator Interconnection facilities" to R2. This added phrase and the statement in 1.4 Data Retention "Generator Owner that owns a generation Protection System" seems to assume that the generator owner and generator interconnection facilities owner is always the same. This is not always the case, and will make this standard language confusing to prepare evidence for. A suggestion would be to revise the language to allow for a separate generator owner and generator interconnection facilities owner.
<p><b>Response:</b> Thank you for your comment. The SDT believes that the language makes clear that an entity need only be concerned with the Elements or Facilities that it owns.</p> <p>The SDT agrees with your comment regarding the language in the Data Retention section and has modified that section as follows: "The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation or generator interconnection Protection System..."</p>		
Southwest Transmission Cooperative, Inc. / ACES Power Marketing	Affirmative	We largely support the changes made by drafting team because we believe the drafting team has provided the best solution in face of a difficult problem. However, in general, we do not support registration of GOs and GOPs as TOs and TOPs or applicability of any TO/TOP requirements to the GO/GOP simply because they have a radial interconnection greater than one mile in length. While there may be some generators that own interconnecting facilities of significant length operated at a significant voltage that could impact BES reliability, we do not believe that the number of generating facilities that fit into that category is significantly large. When one considers that the majority of generators are still owned and operator by utilities that are also registered as a TO and TOP, there is only a minority subset of generators

Organization	Yes or No	Question 7 Comment
		<p>left that could be considered. NERC has the registration for this remaining set of generators and could use the data to evaluate how many of this remaining subset have interconnections owned by the generator that are substantial enough to affect reliability. It seems that NERC could determine the boundaries of this problem before registering anymore GOs and GOPs as TOs and TOPs or before applying additional requirements through this effort on the GOs and GOPs. Subjecting a GO/GOP to any TO/TOP standards requirements should require a clear demonstration of the reliability gap in each instance. Some additional changes are necessary to FAC-001.</p>
<p><b>Response:</b> Thank you for your comment and support. We are unsure as to what changes to FAC-001 you feel are necessary unless you are referring to comments stated previously.</p>		
<p>Ingleside Cogeneration LP (Occidental Chemical)</p>	<p>Yes</p>	<p>Although the SDT is nearing conclusion on the closing of reliability gaps, the unnecessary registration of GOs and GOPs as TOs and TOPs is far from resolved in our view. Ingleside Cogeneration’s concern is based upon NERC’s recent proposal to dictate an interim GO-TO interconnection solution which completely bypasses the Standards Development Process. Frankly, it seriously brings to question the nature of the consensus-driven process - which appears to be moving in a dictatorial direction.</p>
<p><b>Response:</b> Thank you for your comment and support.</p>		
<p>American Wind Energy Association</p>	<p>Yes</p>	<p>AWEA believes that the standards modifications proposed by the SDT should address any genuine reliability gap with regard to generator lead lines, rather than just perceived but unsupported threats. To that end, we support the approach that the SDT appears to be taking of modifying a limited number of applicable standards so that they apply to GO/GOP lead lines. In particular, we fully support the fact that the SDT recognizes that GO/GOPs should not automatically be required to register as TO/TOPs simply because of their ownership of generator lead lines. The SDT correctly recognizes that such registration should be done based on a case-by-case determination. As already noted, registering a GO/GOP as a TO/TOP may actually decrease reliability.</p>



Organization	Yes or No	Question 7 Comment
<b>Response:</b> Thank you for your comment and support.		
RES Americas Development	Yes	We believe that the standards modifications proposed by the SDT should address any genuine reliability gap with regard to generator lead lines, rather than just perceived but unsupported threats. To that end, we support the approach that the SDT appears to be taking of modifying a limited number of applicable standards so that they apply to GO/GOP lead lines. In particular, we fully support the fact that the SDT recognizes that GO/GOPs should not automatically be required to register as TO/TOPs simply because of their ownership of generator lead lines. The SDT correctly recognizes that such registration should be done based on a case-by-case determination. As already noted, registering a GO/GOP as a TO/TOP may actually decrease reliability.
<b>Response:</b> Thank you for your comment and support.		
Southwest Power Pool Standards Development Team	Yes	
Northeast Power Coordinating Council, Northeast Power Coordinating Council	Yes	
MRO NSRF	Yes	
SERC Planning Standards Subcommittee	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
ACES Power Marketing	Yes	

Organization	Yes or No	Question 7 Comment
Standards Collaborators		
Electric Power Supply Association	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Exelon	Yes	
Seattle City Light	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
Ameren	Yes	
American Transmission Company	Yes	
Sempra Generation	Yes	
Xcel Energy	Yes	

Organization	Yes or No	Question 7 Comment
Cowlitz County PUD	Yes	
Constellation Power Source Generation	Yes	
Puget Sound Energy, Inc.		
Compliance & Responsibility Organization		
Bonneville Power Administration		
South Carolina Electric and Gas		
Consolidated Edison Co. of NY, Inc.		
Entergy Services		
ReliabilityFirst		
Tennessee Valley Authority		

8. If you answered “yes” to Question 7, are the modifications the SDT has made in this posting the appropriate ones?

**Summary Consideration:**

The SDT thanks all stakeholders for their comments. In this section, commenters either offered their support or directed the SDT to their comments on other questions in this report.

Organization	Yes or No	Question 8 Comment
Ameren	No	Please refer to our comments in responses to #3, #4, and #5 above.
<b>Response:</b> Please see the SDT’s responses to Questions 3, 4, and 5.		
Texas Reliability Entity	No	See comment 6.
<b>Response:</b> Please see the SDT’s response to Question 6.		
Ingleside Cogeneration LP (Occidental Chemical)	No	See comments to questions 1 through 4.
<b>Response:</b> Please see the SDT’s responses to Questions 1-4.		
SERC Planning Standards Subcommittee	No	See our comments above for question # 3.
<b>Response:</b> Please see the SDT’s response to Question 3.		
South Carolina Electric and Gas	No	The modifications are appropriate with the exception noted in question #3.
<b>Response:</b> Please see the SDT’s response to Question 3.		
ACES Power Marketing	No	The modifications are largely the appropriate ones with the exceptions we noted in Q1

Organization	Yes or No	Question 8 Comment
Standards Collaborators		and Q10.
<b>Response:</b> Please see the SDT’s responses to Questions 1 and 10.		
Southwest Power Pool Standards Development Team	No	We agree that the standards being addressed are correct. See above comments. There are some issues with the determination of which facilities are deemed BES since ownership of what may be a BES facility may not always be by a Transmission Owner. All relevant standards should apply to BES facilities regardless of ownership.
<b>Response:</b> Thank you for your comment.		
PSEG	No	
<b>Response:</b>		
SERC OC Standards Review Group		See comments on Question 7. If the standards referenced in question 7 are FAC-001, FAC-003 and PRC-004, we would answer yes to this question.
<b>Response:</b> Thank you for your comment and support.		
Southern Company	Yes	“The version history table is incorrect - change version 3 to version 2.1.”
<b>Response:</b> Thank you for your comment. We have made this change.		
RES Americas Development/ American Wind Energy Association	Yes	For the most, we agree that the SDT proposal strikes a reasonable balance and provides the requisite level of clarity and certainty necessary for GO/GOPs to understand their responsibilities and compliance requirements.
<b>Response:</b> Thank you for your comment and support.		
MRO NSRF	Yes	The NSRF agrees if the drafting team incorporates as suggested improvements

Organization	Yes or No	Question 8 Comment
<b>Response:</b> Thank you for your comment and support.		
Northeast Power Coordinating Council, Northeast Power Coordinating Council	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
Electric Power Supply Association	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Exelon	Yes	
Seattle City Light	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
American Transmission	Yes	

Organization	Yes or No	Question 8 Comment
Company		
Sempra Generation	Yes	
Xcel Energy	Yes	
Cowlitz County PUD	Yes	
Constellation Power Source Generation	Yes	

**9. If you answered “no” to Question 7, what standards need to be added or removed to achieve the SDT’s goal? Please provide technical justification for your answer.**

**Summary Consideration:**

The SDT thanks all stakeholders who submitted comments. Few stakeholders suggested that standards need to be added or removed to achieve the SDT’s goal.

One commenter pointed out that PRC-005-1a required the same kind of change made in the proposed PRC-004-2.1a to ensure that generator interconnection Facility Protection Systems are included within that standard. The SDT agrees with this suggestion and has initiated a process to modify R1 and R2 in PRC-005-1a.

A few commenters returned to FAC-001-1 and stated their concern about the feasibility of adding FAC-001-1 to the applicability section of this standard. The SDT agrees with commenters that the issues surrounding the interconnection of a third party Facility to a GO’s existing Facilities are complex ones, and reminded commenters that it did its best to address these complexities in the resource document titled “[Technical Justification: FAC-001-1](#).” The SDT also points out that if the GO is part of an RTO, then the GO will be coordinating any interconnection studies either directly or indirectly with the RTO interconnection process. If the GO is not part of an RTO, then the GO will be required to follow the pro forma interconnection procedures from Order 2003. The Order 2003 procedures require the GO to coordinate any studies with an affected system which could include Facilities owned by one, or more, TO on the other side of the GO’s existing point of interconnection. The SDT acknowledges that upon interconnection of a third party, other standards or registrations may apply as appropriate.

Some commenters suggested that the SDT reexamine the standards cited in the Milford and Cedar Creek FERC orders. The SDT continues to find clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards and not requiring the GO or GOP to register as a TO or TOP. However, to address stakeholder concern, the SDT has expanded its technical justification document (posted under “Supporting Materials”) to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive.

Organization	Yes or No	Question 9 Comment
Cowlitz County PUD	No	N/A
Manitoba Hydro	No	See question 7 comments.



Organization	Yes or No	Question 9 Comment
<p><b>Response:</b> See the SDT’s response to Question 7.</p>		
<p>Southern Company</p>	<p>Yes</p>	<p>Southern does not think that the revision to FAC-001-1 is necessary. A Generator Owner (GO) cannot assess reliability impacts to the Bulk Electric System (BES) and determine acceptability without support and involvement of the applicable owner and operator of the Transmission System (i.e., the “interconnected TO” or “interconnected TP”). A generator tie-line does not equate to a Transmission System. A GO must already adhere to a TO’s Facility connection requirements whether the GO wants to connect additional facilities or a third parties’ facilities to its own interconnection Facilities. Stated another way, the GO does not need Facility Connection requirements to govern how multiple units are tied to a collector bus so why are they needed for a third party to connect to an existing tie-line? In either case it is the interconnected TO or interconnected TP that has connection requirements that must be fulfilled. The GO’s Interconnection Agreement would prohibit it from connecting additional facilities without a new application for Interconnection Service with its interconnected TO or interconnected TP. A GO should not need to develop “connection requirements” unless it is in the business of owning and operating facilities independently of its interconnected TO or interconnected TP. We do not believe a reliability gap exists in FAC-001-1 because the requestor for interconnecting another Facility to an existing generation Facility must coordinate with the applicable TO, TP, and PA in accordance with FAC-002-0 to ensure they meet all applicable facility connection and performance requirements. If and when there is an agreement in place for a third party to connect to a generator tie-line then the tie-line would become part of the integrated system and its purpose and the owner’s function would likely warrant registration as a TO/TOP and FAC-001 would then apply. The following excerpt from the 2010-07 Background Resource White Paper acknowledges that this may be necessary: “The drafting team also acknowledges that, if another party interconnects to a Facility owned by a Generator Owner, there may be the need to address MOD or TPL standards. However, the drafting team believes that this, too, is best handled through specific evaluation, perhaps accompanied by changes to the</p>

Organization	Yes or No	Question 9 Comment
		<p>compliance registry. Entities that face this kind of scenario may also meet criteria applicable to other registrations such as Transmission Service Provider or Transmission Planner.” [Arguments related to jurisdictional, interconnection policy and open access transmission tariff issues](1) Because of (a) jurisdiction under Section 215, (b) FERC’s interconnection policy, and (c) the requirements of the pro forma open access transmission tariff (OATT), a GO should not be required to comply with FAC-001-1 until that GO’s generating Facility reaches commercial operation. NERC should not make facilities subject to the mandatory reliability standards before the facilities are actually part of the BES.(a) Jurisdiction under FPA Section 215. First, it is not clear that NERC or FERC has jurisdiction under FPA Section 215 to require generation facilities that have not actually reached commercial operation to be subject to reliability standards. Section 215(a)(2) of the FPA defines the “Electric Reliability Organization” as “the organization certified by the Commission ... the purpose of which is to establish and enforce reliability standards for the bulk-power system, subject to Commission review.” Further, (a)(3) provides that “The term ‘reliability standard’ means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system. The term includes requirements for the operation of existing bulk-power system facilities ... the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system ....” Thus, under Section 215 NERC can develop reliability standards that address requirements for existing bulk-power system facilities (i.e., facilities that have reached “commercial operation”) and for the design of planned additions or modifications. It is logical to interpret the phrase “design of new facilities” as meaning that new facilities must be designed to comply with existing reliability standards. However, it is not clear that this provision should be interpreted as requiring that a generating facility that has not yet reached commercial operation should be subject to reliability standards (including audit and penalties). Therefore, the GO with the existing generation facilities should not be required to incorporate the proposed generation facility into its Facility connection requirements before the proposed generation facility is subject to NERC or FERC jurisdiction. (b) FERC’s</p>

Organization	Yes or No	Question 9 Comment
		<p>interconnection policy. In addition, the revised FAC-001 would appear to place restrictions on interconnection customers in contravention of Order Nos. 2003 and 2006 (Standard Large and Small Interconnection Procedures and Agreements). FERC was very concerned about the ability of interconnection customers to interconnect their generating facilities and gave them a fair amount of flexibility. However, this revised FAC-001 would appear to restrict some of this flexibility.(i) Order No. 2003 gives the interconnection customer the ability to terminate a proposed interconnection on ninety days notice. Therefore, the interconnection customer is not required to build the facility. However, this revised FAC-001 appears to assume that the interconnection customer does not have this flexibility. What if the interconnection customer (the GO building a new generator on its site or the third party building a new generation facility) decides to terminate the Large Generator Interconnection Agreement (LGIA) or not proceed with the generation facility? In such event, the GO may be required to revert to its previous Facility connection requirements in order to accommodate the original configuration. (ii) The LGIA permits modifications to the proposed interconnection. How would this affect the Facility connection requirements? How long would the GO have to revise its Facility connection requirements? In the event that there is a single modification, or perhaps multiple modifications, how does the GO stay in compliance with this standard? (iii) FAC-001-1, R4 provides that each GO with Facility connection requirements and each TO shall maintain Facility connection requirements and make documentation of these requirements available to users of the Transmission System upon request. However, Large Generator Interconnection Procedures (LGIP), Section 3.4 requires the posting of certain interconnection information but the identity of the interconnection customer is not to be disclosed (unless it is an Affiliate). Requirement R4 would appear to potentially require disclosure of information and (more importantly) of the interconnection customer's identity in contravention of the requirements in Order No. 2003 and the LGIP.(c) OATT requirements. The definition of “applicable Generator Owner” (Section 4.2.1) and Requirement R2 provide that the GO will have an executed Agreement to evaluate the impact of interconnecting a new facility to the GO’s</p>

Organization	Yes or No	Question 9 Comment
		<p>existing generation facility. This statement is ambiguous. This statement could be understood to mean that the GO of the existing generation Facility will enter into an Agreement with the GO proposing to interconnect and the existing GO will evaluate the impact of the proposed interconnection. However, requests to interconnect new generation are processed under an OATT. In that case, it would be the Transmission Provider (not the existing GO) that would evaluate the impact of interconnecting the new facility. Thus, the language in FAC-001-1 would need to be revised to clarify that the owner of the new facility will need to interconnect under the OATT of an appropriate Transmission Provider (i.e., the Transmission Provider to which the existing GO is interconnected, not with the existing GO). Therefore, the owner of the new facility will most likely be the entity with the executed Agreement (with the Transmission Provider). Another consideration is that the existing GO could be developing a merchant transmission line. In that case, the existing GO would need to evaluate whether it needs have its own OATT and OASIS. In that case, the new generator owner would be interconnecting to the existing GO. However, the existing GO's line would not be a generator tie-line. This issue is not clear from the draft standard. (2) The following are suggested changes to FAC-001-1. (a) We recommend the Purpose statement be revised to state, "To avoid adverse impacts on BES reliability..." (b) It is unclear in Applicability section 4.2.1 that the term "Agreement" means that the GO has an executed agreement with a TO/TSP or that the GO and the third party have an executed agreement. Without further explanation, the capitalized term "Agreement" has the effect of introducing confusion. If the SDT does not intend to propose a new addition to the NERC Glossary of Terms, it should use the lower case term, "agreement." With respect to the capitalized term, "Transmission System," the SDT should consider clarifying if it intends to propose adding this to the Glossary. (3) Effect of the proposed revisions to FAC-001-1 on FAC-002-1.(a) As drafted, there are scenarios under which a new GO may attempt to interconnect to an existing GO even though, as explained above, the interconnection should actually be done to the appropriate Transmission Provider. If the appropriate Transmission Provider is not included in the evaluation of the interconnection various types of harm may occur. In</p>

Organization	Yes or No	Question 9 Comment
		<p>such event, the TPs and PAs should be indemnified from any liability with respect to performance of the evaluations required by FAC-002. (b) FAC-001 and FAC-002 should be revised to be clear that the existing GO and any new GOs must coordinate any interconnection with the appropriate Transmission Provider, TP and PA.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees this is a complex issue and did its best to outline how it arrived at its position in the document titled "<a href="#">Technical Justification: FAC-001-1.</a>"</p> <p>The SDT points out that if the GO is part of an RTO, then the GO will be coordinating any interconnection studies either directly or indirectly with the RTO interconnection process. If the GO is not part of an RTO, then the GO will be required to follow the pro forma interconnection procedures from Order 2003. The Order 2003 procedures require the GO to coordinate any studies with an affected system which could include Facilities owned by one, or more, TO on the other side of the GO's existing point of interconnection.</p> <p>The SDT does agree that upon interconnection of a third party, other standards or registrations may apply as appropriate.</p>		
PSEG	Yes	<p>We believe that the Ad Hoc Group's suggestions regarding PRC-005-1 - Transmission and Generation Protection System Maintenance were correct and that this standard should have been modified by the SDT in a manner similar to the way the SDT modified PRC-004-2. This would require modifying R1 and R2 in PRC-005-1a (the current version) to include protection systems in the generator interconnection Facility. In addition, the SDT should evaluate modifying PER-002-0 - Operation Personnel Training. In doing so the SDT completes one of the open FERC directives in Order 693. Paragraph 1363 addresses GOP training:1363. Further, the Commission agrees with MidAmerican, SDG&amp;E and others that the experience and knowledge required by transmission operators about Bulk-Power System operations goes well beyond what is needed by generation operators; therefore, training for generator operators need not be as extensive as that required for transmission operators. Accordingly, the training requirements developed by the ERO should be tailored in their scope, content and duration so as to be appropriate to generation operations personnel and the objective of promoting system reliability. Thus, in addition to modifying the Reliability Standard to identify generator operators as applicable entities, we direct the ERO to develop specific Requirements addressing the scope,</p>

Organization	Yes or No	Question 9 Comment
		content and duration appropriate for generator operator personnel.
<p><b>Response:</b> Thank you for your comment. The SDT agrees with the comment concerning PRC-005-1a and will be initiating a process to make that change.</p> <p>With respect to PER-002-0, the SDT continues to find that there are no clear and technical reliability reasons that support adding GOP requirements to any PER standard <i>based on the fact that the GOP operates a generator interconnection Facility</i>. While the SDT does not necessarily disagree that some training requirements for GOPs may be necessary, it does not see how these changes fall within its scope.</p>		
Ingleside Cogeneration LP (Occidental Chemical)		Ingleside Cogeneration LP believes that the set of standards proposed by the SDT is technologically accurate and defensible. The open issue is if the ERO and FERC expect more standards to be included - whether based upon sound reliability principals or not.
<p><b>Response:</b> Thank you for your comment and support.</p>		
Western Electricity Coordinating Council		Please see response to question #7.
<p><b>Response:</b> See the SDT's response to Question 7.</p>		
Texas Reliability Entity		See comment 6.
<p><b>Response:</b> See the SDT's response to Question 6.</p>		
SERC OC Standards Review Group		See comments on Questions 7 & 8.
<p><b>Response:</b> See the SDT's responses to Questions 7 and 8.</p>		
Florida Municipal Power		see response to Question 7

Organization	Yes or No	Question 9 Comment
Agency		
<p><b>Response:</b> See the SDT’s response to Questions 7.</p>		
Manitoba Hydro		<p>The revision to FAC-001-1 R2 may be problematic, depending on what was intended. Under the revised requirement, the obligation to comply is dependent on the execution of an agreement to evaluate reliability impacts under FAC-002-1. However, FAC-002-1 does not clearly require the execution of an agreement by the Generator Owner. FAC-002-1 only requires the Generator Owner to “coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority”. Accordingly if a Generator Owner coordinates without executing an agreement to perform an assessment, compliance with FAC-001 R1 will not be required.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees this is a complex issue and did its best to outline how it arrived at its position in the document titled “<a href="#">Technical Justification: FAC-001-1</a>.”</p>		
Southwest Power Pool Regional Entity		<p>The SDT should consider the standards that FERC identified in 135 FERC ¶ 61,241.</p>
<p><b>Response:</b> Thank you for your comment. The NERC <a href="#">Standard Processes Manual</a> does not address the issue of how to deal with FERC Orders (that don’t include explicit directives). However, based on your and other comments, we have expanded our technical justification document (posted under “Supporting Materials”) to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.</p>		

**10. Do you have any other comments that you have not yet addressed? If yes, please explain.****Summary Consideration:**

The SDT thanks all stakeholders for their comments. In this section, many stakeholders offered supportive comments. Others offered a variety of suggestions, many of which were addressed.

One commenter suggested that the word “system” should not be capitalized in “Transmission System” in FAC-001-1 because the NERC glossary term “System” does not apply within the standard. The SDT agreed with this suggestion, and changed all references to “Transmission System” to “interconnected Transmission systems” for consistency in other parts of the standard and with FAC-002. Another commenter pointed out that “within” should be “with” in Section 4.2.1, and the SDT made this change.

A few commenters repeated their concern with the exclusion in FAC-003 for GOs with specific kinds of interconnection Facilities. For these commenters, the SDT reemphasized that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.

To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight.

Some stakeholders offered comments that were outside the scope of this SDT’s work. A few offered comments on the overall strategy of the FAC-003-2 standard, and the SDT informed them that these comments should have been submitted when the Project 2007-7 Vegetation Management posted its work for comment.

One commenter suggested changes to the VSLs for R1 and R4. Because the SDT made no changes to these requirements, modifying the VSLs for these requirements is outside the scope of this team. This item will be added to the issues database.

Several stakeholders suggested the SDT review the standards cited in the draft NERC directive regarding generator interconnection leads and in the FERC orders regarding Milford and Cedar Creek. The SDT continues to find clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards and not requiring the GO or GOP to register as a TO or TOP. However, to address stakeholder concern, the SDT has expanded its technical justification document (posted under “Supporting Materials”) to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive.



Organization	Yes or No	Question 10 Comment
Gainesville Regional Utilities	Negative	<p>1. It would seem that the impetus for FAC003 is to eliminate vegetation related outages within the rights-of-way as defined and subject to the exclusions as stated in footnote</p> <p>2. Thus the requirement is to manage the ROW to prevent vegetation related sustained outages with the measure being no outages. With grow-ins and fall-ins from within the defined ROW being controllable factors. 2. Including encroachments leaves the door open for fines to be imposed with no actual outage(s) having occurred. This may be like being found guilty of a crime that has not yet taken place.</p> <p>3. Combine vegetation related sustained outages by “grow-ins” and “blowing together of lines and vegetation located inside the ROW” as one item as they are both consequences of the growth of vegetation either vertically and horizontally.</p> <p>4. Leave vegetation related sustained outages by “fall-in” as a standalone as this will be related to structural problems occurring from a variety of sources.</p> <p>5. Combine R3 and R7 to R1 (development and implementation of a Transmission Vegetation Management Plan which shall include documented maintenance strategies or procedures or processes or specifications, delineation of an annual work plan and completion of same). Thus this would be the competency based requirements as a program without execution is meaningless.</p> <p>6. R1 and R2 become R2 and R3.</p>
<p><b>Response:</b> Thank you for your comment. This is outside the scope of the <a href="#">SAR</a> for this project. This SDT did review comments submitted as part of the <a href="#">Project 2007-07</a> effort and found that a response to this comment was provided. No change made.</p>		
Northern Indiana Public Service Co.	Negative	Ballot needs work
<p><b>Response:</b> The SDT does not understand your specific concern.</p>		

Organization	Yes or No	Question 10 Comment
PSEG Energy Resources & Trade LLC, PSEG Fossil LLC, Public Service Electric and Gas Co.	Negative	FAC-003-X is not applicable since FAC-003-2 was approved by the BOT on November 4, 2011
<p><b>Response:</b> Thank you for your comment. You are correct that in November 2011, NERC’s Board of Trustees adopted FAC-003-2 – Transmission Vegetation Management (developed under Project 2007-07 Vegetation Management). Based on this approval, NERC staff will file FAC-003-2 with the applicable regulatory authorities. The Project 2010-07 SDT will move forward with ballots for both FAC-003-3 (proposed changes to the BOT-adopted FAC-003-2) and FAC-003-X (proposed changes to the FERC-approved FAC-003-1) with the intention of eventually only filing FAC-003-3. The SDT has elected to carry FAC-003-X through to ballot because if FAC-003-2 and FAC-003-3 are not approved by FERC, the SDT wants to be ready to file FAC-003-X to ensure that there is a functional entity responsible for managing vegetation on the piece of line commonly known as the generator interconnection Facility.</p> <p>Note that for its recirculation ballot, the SDT will be balloting <b>both</b> FAC-003-3 and FAC-003-X, but stakeholders should <b>not</b> vote as though they are choosing one or the other. As stated above, the SDT plans to present FAC-003-3 alone to NERC’s Board of Trustees, but it wants to have FAC-003-X ready to submit to the Board if, for some reason, neither FAC-003-2 nor FAC-003-3 are approved by FERC. Members of the ballot body should vote on the merits of each version of FAC-003 individually. <b>In other words, stakeholders who support adding GOs to the applicability of FAC-003 should vote in the affirmative for both FAC-003-3 and FAC-003-X.</b></p>		
Hydro-Quebec TransEnergie	Negative	Hydro-Quebec TransEnergie is casting a negative vote again because our comment from the last posting was not considered in the current draft: The minimum frequency of Vegetation Inspection should be based upon an average growth rates of smaller regions than all North America. Example, above the latitude of 50 degrees North, the vegetation growth rates is limited. The Vegetation Inspection frequency in the territories located above 50 degrees of latitude must be relaxed to 3 years.
<p><b>Response:</b> Thank you for your comment. This is outside the scope of the <a href="#">SAR</a> for this project. This SDT did review comments submitted as part of the <a href="#">Project 2007-07</a> effort and did not find this comment had been submitted as part of that project effort. No changes made.</p>		
New Brunswick System	Negative	Since NBSO voted 'affirmative' for FAC-003-3, it makes sense for us to vote 'negative'

Organization	Yes or No	Question 10 Comment
Operator		for this standard.
<p><b>Response:</b> Thank you for your comment. In November 2011, NERC’s Board of Trustees adopted FAC-003-2 – Transmission Vegetation Management (developed under Project 2007-07 Vegetation Management). Based on this approval, NERC staff will file FAC-003-2 with the applicable regulatory authorities. The Project 2010-07 SDT will move forward with ballots for both FAC-003-3 (proposed changes to the BOT-adopted FAC-003-2) and FAC-003-X (proposed changes to the FERC-approved FAC-003-1) with the intention of eventually only filing FAC-003-3. The SDT has elected to carry FAC-003-X through to ballot because if FAC-003-2 and FAC-003-3 are not approved by FERC, the SDT wants to be ready to file FAC-003-X to ensure that there is a functional entity responsible for managing vegetation on the piece of line commonly known as the generator interconnection Facility.</p> <p>Note that for its recirculation ballot, the SDT will be balloting <b>both</b> FAC-003-3 and FAC-003-X, but stakeholders should <b>not</b> vote as though they are choosing one or the other. As stated above, the SDT plans to present FAC-003-3 alone to NERC’s Board of Trustees, but it wants to have FAC-003-X ready to submit to the Board if, for some reason, neither FAC-003-2 nor FAC-003-3 are approved by FERC. Members of the ballot body should vote on the merits of each version of FAC-003 individually. <b>In other words, stakeholders who support adding GOs to the applicability of FAC-003 should vote in the affirmative for both FAC-003-3 and FAC-003-X.</b></p>		
PSEG Energy Resources & Trade LLC/ Public Service Electric and Gas Co./ PSEG Fossil LLC	Negative	The phrase “generator Facility” should be “generator Transmission Facility,” and the phrase “Transmission System” should be “Transmission system.”
<p><b>Response:</b> Thank you for your comment. We agree with your change to “Transmission system” but not to the addition of “Transmission” in the phrase “generator Facility.” The SDT does not agree with labeling a GO’s Facility as “Transmission,” in part because in some areas (like Texas), GOs, by statute, can’t own Transmission. It was also brought to the SDT’s attention that in most cases, the Facility in question is referred to as the Interconnection Facility in documents filed by the GO with FERC. Therefore, the SDT intentionally modified language so that a Facility owned by a generation entity did not contain the term “Transmission.”</p>		
SERC Reliability Corporation	Negative	There should not be a weak link under the standard. This proposed revision would create a weak-link where a portion of the otherwise covered right-of-way would be exposed.
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled <a href="#">“Technical Justification Project 2010-07 Generator</a></p>		

Organization	Yes or No	Question 10 Comment
<p><u>Requirements at the Transmission Interface</u>,” the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight.</p>		
<p>New York State Department of Public Service/ National Association of Regulatory Utility Commissioners</p>	<p>Negative</p>	<p>Understand that there is an open issue regarding the availability of generation compliance documentation that needs to be satisfactorily addressed.</p>
<p><b>Response:</b> The SDT does not understand your specific concern.</p>		
<p>Infigen Energy US</p>	<p>Affirmative</p>	<p>Infigen supports the efforts of the SDT to ensure that Protection System Misoperations affecting the reliability of the BES are thoroughly analyzed and mitigated. Generator Owners are already analyzing Misoperations as/if they occur, and are employing Corrective Action Plans to avoid future Misoperations. We support maintaining "reasonable and appropriate" preventative measures and risk assessment tools to ensure that misoperations are evaluated and corrected expediently.</p>
<p><b>Response:</b> Thank you for your comment and support.</p>		
<p>PPL EnergyPlus LLC/PPL NERC Registered Affiliates</p>	<p>Affirmative</p>	<p>PPL Generation, LLC, on behalf of its NERC-registered subsidiaries, appreciates the effort by the Standard Development Team to address the GO-TO interface issues in a manner that enhances the reliability of the BES without adding unnecessary burden on Generators. As registered GOs/GOPs, the PPL Generation registered entities agree with the changes made by the SDT to these three standards. To the extent that GOs/GOPs are required to register as TOs/TOPs, PPL Generation would have significant concerns with meeting the compliance requirements applicable to TOs in the standards included in the scope of this Project, as well as other TO/TOP</p>

Organization	Yes or No	Question 10 Comment
		requirements throughout other NERC standards.
<b>Response:</b> Thank you for your comment and support.		
SERC Reliability Corporation	Affirmative	The Generator Owner may be required to self-certify and report periodically to the region whether they have become applicable to the standard.
<b>Response:</b> Thank you for your comment and support.		
Southwest Transmission Cooperative, Inc./ ACES Power Marketing Standards Collaborators/ ACES Power Marketing	Affirmative	The modifications to PRC-004-2.1 R2 could be interpreted as requiring the GO to analyze Protection System Misoperations on the generator interconnection Facility even if it does not own the Facility. We suggest modifying the requirement as shown below to address this issue.”The Generator Owner shall analyze Protection System Misoperations on its generator and generator interconnection Facility that it owns ...”
<b>Response:</b> Thank you for your comment. The SDT believes that the language makes clear that an entity need only be concerned with the Elements or Facilities that it owns.		
SERC Reliability Corporation	Affirmative	With the understanding the Generator Interconnection Facilities will be grouped with Transmission Protection Systems for analysis at the regional level.
<b>Response:</b> Thank you for your comment and support.		
Entergy Services		We suggest that the Vegetation Management Standards should be consistent for both the TO and GO facilities. We would also like to suggest an additional Recommendation for added clarity regarding Category 3 Outages (Off-ROW Fall-in Outages). We understand that the Category 3 Outages are not a violation of the Standard, but we feel that there should be some level of comment added within the Standard clearly stating that these Outages are “Reportable Only” during the Quarterly Outage reports to the RE’s, and that there are no associated violations/sanctions for this Category Of Outage, and that an Off-ROW fall-in outage

Organization	Yes or No	Question 10 Comment
		<p>would not be considered an encroachment into the MVCD in any way. The Technical Reference Document does a good job of clearly stating this in the Introduction on Page 5 (“This standard is not intended to address outages such as those due to vegetation fall-ins or blow-ins from outside the Right-of-Way, vandalism, human activities or acts of nature.”) and we feel that this should also be stated clearly in the Standard.</p>
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled <a href="#">“Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface,”</a> the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight.</p> <p>The remainder of your comment is outside the scope of this SDT.</p>		
Southern Company		<p>We agree with the 2010-17 Standard Drafting Team’s conclusion to not modify other standards such as those mentioned on page 4 of the Technical Justification document. In addition, we wish to provide the following support for exclusion of these specific standards. Southern Company believes NERC’s Project 2010-07 SDT must challenge making revisions to the standards included in the FERC order on Cedar Creek and Milford. (This order supports NERC’s requirement for those entities to register as a TO/TOP due to their ownership of generator interconnection circuits &gt; 100kV.) We believe there are clear technical and reliability-based reasons that support not adding GO and GOP requirements to these standards and not requiring the GO or GOP to register as a TO or TOP. Furthermore, we also believe there are clear distinctions between GO/GOP responsibilities and TO/TOP responsibilities that must be maintained to ensure BES reliability. Revising standards to assign TO/TOP responsibilities to a GO/GOP or requiring a GO/GOP to register as a TO/TOP because of generator interconnection circuits &gt; 100kV will reduce the clarity of these responsibilities. We have provided specific comments on each standard below:</p>

Organization	Yes or No	Question 10 Comment
		<p>EOP-005-1 R1, R2, R6, R7R1 and R2 require each TOP to have and maintain a system restoration plan. R6 requires the TOP to train its operating personnel in implementing this plan. R7 requires the TOP to verify its restoration plan by actual testing or simulation. These requirements are clearly the role and responsibility of the TOP, not a GO/GOP who happens to have generator interconnection facilities in the TOP’s control area. The GOP’s roles and responsibilities are clearly and appropriately addressed EOP-005-2. The presence of a generator interconnection circuit &gt; 100kV that happens to be owned by the GO instead of the TOP fundamentally does not change the roles and responsibilities of the TOP or the GOP. Thus, no changes due to EOP-005 are needed.</p> <p>FAC-014-2, R2: FAC-014-2 R2 states “The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator’s SOL Methodology.” FAC-014-2 R2 should not be revised to include GOPs. The GO is required by FAC-008-1 R1 and FAC-009-1 (FERC approved version) and pending FAC-008-3 R3 and R6 (FAC-008-3 filed with FERC for approval) to document the Facility Ratings for a GO-owned generator interconnection circuit &gt;100kV. The established Facility Rating must respect the most limiting applicable equipment rating in the circuit and must consider operating limitations and ambient conditions. The thermal or ampere rating of this circuit would equal its ampere operating limit and should be conveyed by the GO to the GOP if they are not the same entity. The operating voltage limits for this circuit are established by the applicable TO/TOP, not the GO or GOP. Therefore, we believe adding the GO to FAC-014-2 R2 would be redundant.</p> <p>PER-003-1 R2, R2.1, R2.2PER-003-1 R2 and its sub-requirements state:”R2. Each Transmission Operator shall staff its Real-time operating positions performing Transmission Operator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates (1 ) : [Risk Factor: High][Time Horizon: Real-time Operations]: R2.1. Areas of Competency R2.1.1. Transmission operations R2.1.2. Emergency preparedness and operations R2.1.3. System operations R2.1.4.</p>

Organization	Yes or No	Question 10 Comment
		<p>Protection and control R2.1.5. Voltage and reactive R2.2. Certificates o Reliability Operator o Balancing, Interchange and Transmission Operator o Transmission Operator This requirement is specifically for TOPs. Personnel training for GOPs needs to be addressed separately and not mingled with responsibilities of the TOP. The GOPs role in supporting BES reliability needs to be clearly understood and defined prior to establishing training requirements in the standards.</p> <p>PRC-001-1, R2, R2.2, R4, R6Generator Operators (GOPs) and the scope of protection equipment for generation interconnection Facilities are already appropriately accounted for in this standard in requirement R2 and sub-requirement R2.2 The language used in requirement R2 which applies to the GOP uses the general terms “relay or equipment failures” which would include not only generator relaying, but generator interconnection relaying in the GOPs scope as well. The GOP is required to notify the TOP and Host BA in R2.1 “if a protective relay or equipment failure reduces system reliability.” Requirement R2.2 requires the affected TOP to notify its RC and affected TOPs and BAs. Thus, applying R2.2 to a GOP would be redundant to R2.1. Requirement R4 states, “Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.” A generator interconnection tie line does not constitute a ‘major tie line” or major “interconnection with neighboring GOPs, TOPs, and BAs.” Thus, R4 should not be revised to include GOPs. If a GO exists within NERC that does own such interconnection facilities, the responsibility for coordination of protection systems on such a line or interconnection should be the responsibility of the TOP in that area, not the GO/GOP. This may require formal agreements between the TO/TOP and GO/GOP, since the GO may own protection equipment on his end. The same logic applies to R6. R6 states, “Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.” This is clearly the responsibility of the TOP and/or BA, not a GO/GOP who happens to have generator interconnection facilities in the area. An SPS function by definition is to</p>



Organization	Yes or No	Question 10 Comment
		<p>maintain BES reliability. If a GO/GOP has equipment within the equipment scope of a Special Protection System (SPS), responsibility for monitoring the SPS should be conveyed in a formal agreement as appropriate.</p> <p>TOP-001-1 R1 Requirement R1 states, “Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.” This is clearly the responsibility of the TOP, not a GO/GOP who happens to have generator interconnection facilities in the TOP’s area. Thus, R1 should not be applied to a GO/GOP who owns or operates generator interconnection facilities. Furthermore, TOP-001-1 R3 (proposed to be covered in the future in the proposed IRO-001-2 R2 and R3) appropriately requires the GOP to comply with reliability directives issued by the TO “unless such actions would violate safety, equipment, regulatory or statutory requirements.” These requirements effectively give the TOP the necessary decision-making authority over operation of all generator Facilities up to the point of interconnection. They also give the GOP the necessary authority to take appropriate actions to ensure safety and protection of the GO’s equipment. Thus, no changes to TOP-001-1 are necessary.</p> <p>TOP-004-2 R6, R6.1, R6.2, R6.3, R6.4 Requirement R6 and its sub-requirements state: “R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: R6.1. Monitoring and controlling voltage levels and real and reactive power flows. R6.2. Switching transmission elements. R6.3. Planned outages of transmission elements. R6.4. Responding to IROL and SOL violations.” These are clearly the responsibility of the TOP, not a GO/GOP who happens to have generator interconnection facilities in the TOP’s area. Thus, these requirements should not be applied to a GO/GOP who owns or operates generator interconnection facilities. The same logic applies here as stated above in our discussion on TOP-001-1. We believe it is inappropriate and would be adverse to BES reliability to apply these requirements</p>

Organization	Yes or No	Question 10 Comment
		<p>to a GOP. TOP-004-2 effectively gives the TOP the necessary decision-making authority over operation of all generator Facilities up to the point of interconnection. They also give the GOP the necessary authority to take appropriate actions to ensure safety and protection of the GO’s equipment, such as opening high voltage generator output breakers when required to protect the unit. Thus, no changes to TOP-004-2 are necessary. TOP-006-2 R3 Requirement R3 states, “R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel. The intent of this requirement when applied to a GOP is already addressed in PRC-001-1 R1 which states, “Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.” Thus, no change to TOP-006-2 is necessary. ”</p>
<p><b>Response:</b> Thank you for your comment and support. We agree that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards and not requiring the GO or GOP to register as a TO or TOP. We have expanded our technical justification document (posted under “Supporting Materials”) to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive, and many of your explanations are included therein.</p>		
<p>American Wind Energy Association</p>		<p>AWEA appreciates the opportunity to submit these comments on the NERC Project 2010-07. AWEA supports the general direction indicated by both the Generator Requirements at the Transmission Interface Ad Hoc Group and the Project 2010-07 Standards Development Team. We agree with the sentiments from both groups that a GO or GOP that also owns or operates a generator lead line should not be required to register as a TO or TOP strictly because they own or operate a generator lead line. We also agree that requiring these GO/GOPs to comply with all the TO/TOP standards would have little effect on or benefits to reliability of the Bulk Electric System, and could even detract from it. AWEA supports the intent and goal of the SDT to ensure that all generator-owned Facilities are appropriately covered under NERC’s Reliability Standards. We also agree with the SDT that while many GO/GOPs operate Elements and Facilities that might be considered by some entities to be Transmission, these are</p>

Organization	Yes or No	Question 10 Comment
		<p>most often radial Facilities that are not part of the integrated grid, and as such should not be subject to the same standards applicable to TO/TOPs, who own and operate Transmission Elements and Facilities that are part of the integrated grid. Therefore, we support the SDT’s approach of identifying a very limited number of TO/TOP standards, such as FAC-001 and FAC-003, which should also apply to GO/GOP owners of generator lead lines. We would be concerned, however, if additional requirements were added beyond FAC-001, FAC-003, and PRC-004. Consideration of any additional standards with respect to generator lead lines should be done on a standard-by-standard basis, reviewing the applicability of each standard as well as the impact on the reliability of the Bulk Electric System.</p>
<p><b>Response:</b> Thank you for your comment and support.</p>		
<p>Bonneville Power Administration</p>		<p>BPA thanks you for the opportunity to comment on Project 2010-07, Generator Requirements at the Transmission Interface. BPA stands in support of the proposed revisions and has no comments or concerns at this time.</p>
<p><b>Response:</b> Thank you for your comment and support.</p>		
<p>Constellation Power Source Generation</p>		<p>Constellation appreciates and supports the work of the standard drafting team. We recognize the significant time invested by technical experts from industry to consider the appropriate application of reliability standards to address concerns raised about coverage of transmission at the generator interface. The drafting team analysis identified the standards in need of revision to appropriately address the reliability concerns raised. While the revision process focuses on specific standards, it is important to consider the reliability questions in the context of the full complement of reliability standards that apply to entities. For instance, the following standards already apply to generators and relate to the reliability considerations around transmission at the generator interface:</p> <ul style="list-style-type: none"> <li>o PRC-001-1 addresses coordination of protection system components by requiring all GOs to ensure coordination of their protection system with interconnected parties.</li> </ul>

Organization	Yes or No	Question 10 Comment
		<p>Further, FAC-002 requires that all new facilities undergo reviews by the TOP, BA, etc.</p> <ul style="list-style-type: none"> <li>o PRC-004-1 requires all GOs to ensure that they analyze all misoperations on their protection system which would include the protection of the tie line.</li> <li>o TOP standards applicable to GOs aid coordination between a GO and a TO with regards to the generator tie line by requiring all GOs to coordinate all maintenance and emergency outages (both forced and planned) with all applicable interconnected parties. Further, all ISO procedures require the same of GOs.</li> <li>o RC, TOP and/or BA certified operators control and are responsible for overseeing that transmission. According to the NERC functional model, a Generator Operator is defined as “operat(ing) generating unit(s) and perform(ing) the functions of supplying energy and reliability related services.” Given this limited scope, the Generator Operator (GOP) cannot be considered as operating on the same level as the Reliability Coordinator, Transmission Operator or Balancing Authority when it comes to real time information on the status of the BES. The GOP does not monitor and control the BES, rather the GOP only monitors and controls the generators that it operates and relays information to other operating entities.</li> <li>o IRO and TOP standards applicable to GOs include tie lines in their pool of resources to alleviate operational emergencies by requiring all GOs to operate as directed by their TOP, BA, or RC as directed and must render emergency assistance.</li> <li>o FAC-8 and FAC-9 manage rating methodology consistency by requiring all GOs to develop a methodology to rate all equipment, and that the RC has the authority to challenge the GO on that methodology. The onus is on the GO to either change their methodology and rating accordingly, or provide a technical justification as to why they cannot adopt the changes. Further, a generator will never be limited by its tie line, as a generator’s profits are directly tied to its output. Therefore no generator would limit its facility to the equipment that is delivering that output.</li> </ul>

**Response:** Thank you for your comment and support. We agree that it is important to consider the reliability questions in the context of the full complement of reliability standards, and we have endeavored to make these broader connections clear in our revised

Organization	Yes or No	Question 10 Comment
<p>technical justification document (posted under “Supporting Materials”). That document has been expanded to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive, and the kinds of further justifications you also provided are included therein. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.</p>		
Cowlitz County PUD		<p>In answer to the SDT request for feedback on FERC’s Order concerning Cedar Creek and Milford, the District finds no technical reason to add any of the listed standard requirements, and struggles to understand why FERC would even consider this listing as applicable.</p>
<p><b>Response:</b> Thank you for your comment and support.</p>		
Southwest Transmission Cooperative, Inc.		<p>In section 4.2.1 of the Applicability Section, “within” should be “with”. Because NERC’s Glossary of Terms establishes that an Agreement can be verbal and not enforceable by law, section 4.2.1 should be further modified to clarify that it is a legally enforceable and fully executed Agreement. The language in R3 in parenthesis after Generation Owner should be modified to “once required by Requirement R2”. This makes it clearer that R3 does not apply until the GO has an executed Agreement to evaluate a request by a third part to interconnect.</p>
<p><b>Response:</b> Thank you for your comment. We agree that “within” should be “with.” The SDT chose not to adopt the second recommendation as the requirement already contains the term “executed.” The SDT also chose not to adopt the third recommendation as the requirement already contains the parenthetical (in accordance with Requirement R2) which we feel is synonymous with the comment.</p>		
Manitoba Hydro		<p>Manitoba Hydro would also like to point out that if the redline changes are implemented, it will greatly increase the complexity of coordination required under FAC-002-1 for Transmission Planners/Planning Authorities.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees this is a complex issue and did its best to outline how it arrived at its position in the document titled <a href="#">“Technical Justification: FAC-001-1.”</a></p>		

Organization	Yes or No	Question 10 Comment
Compliance & Responsibility Organization		<p>NextEra Energy, Inc. (NextEra) appreciates the work of the Project 2010-07 Generator Requirements at the Transmission Interface Standard Drafting Team (SDT) on a subject that NextEra has a significant interest in resolving. In fact, NextEra has been a member of the SDT and an active observer. Given the recent events - such as (a) the North American Electric Reliability Commission's draft interim directive; (b) the denial of the Milford and Cedar Cheek requests for reconsideration at the Federal Energy Regulatory Commission (FERC) and (c) the record in this case which, at times, suggests the SDT needs to more formally consider the Milford and Cedar Cheek Reliability Standards - NextEra requests that SDT more formally consider the merits of each Reliability Standard adopted the Milford and Cedar Cheek FERC orders and the NERC draft interim directive. Although NextEra does not condone the manner in which NERC issued the interim draft directive and stated so in its comments to NERC on the interim draft directive, NextEra's overarching objective on this issue is to bring a uniform, fair and technically supported approach that resolves the interface issue. Thus, NextEra requests that the SDT (prior to proceeding any further or any additional comments or votes on specific draft Reliability Standards) issue a technical paper that point-by-point addresses the merits of including the Reliability Standards set forth in the FERC Orders and NERC's draft interim directive, and request stakeholder, including NERC staff, comment. For example, this technical paper would likely the merits of NERC's draft interim directive not requiring NERC-certified operators (but require training of interface operators), while FERC's orders require NERC-certified operators. While NextEra does not agree five days of training is necessary for an interface operator, as the draft interim directive appears to propose, NextEra does believe a technical case can be made why NERC-certification is not required, and that some degree of training related to the applicable Reliability Standards is reasonable. Similar, on FAC-003 (as well as several other Standards), the draft interim directive proposes a slightly different approach than the SDT. NextEra would rather these approaches reconciled than be in conflict, with the potential for continued conflict as the SDT's work product proceeds. Further, NextEra requests that the SDT's review the technical merits of NERC's proposed criteria to determine what generator</p>

Organization	Yes or No	Question 10 Comment
		transmission lead is required to comply with additional Reliability Standards. As noted, above, this technical paper should be posted for stakeholder, including NERC staff, comment. Accordingly, while NextEra would have preferred that NERC and the Regional Entities express there interim draft directive approach on the record in this proceeding, NextEra believes it is appropriate for the SDT to draft a comprehensive technical paper that, with an open approach, considers the inclusion of additional Reliability Standards, if appropriate, as a way of building lasting support for its approach.
<p><b>Response:</b> Thank you for your comment and support. We certainly agree that is important for NERC staff and the SDT to continue to work together to try to develop a mutually agreed upon solution for dealing with this reliability gap, and to a certain extent, the SDT has tried to provide the kind of technical paper you suggest in its modified technical justification document (posted under “Supporting Materials”), which has been expanded to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. The SDT does not, at this point, plan to develop a technical paper that discusses the merits of the standards introduced by FERC and NERC, because its current focus is on filing the FAC-001-1, FAC-003-3, and PRC-004-2.1a with FERC. As it moves forward to a final solution, however, this kind of technical paper may prove useful. We appreciate the suggestion.</p>		
Dominion		No
Tennessee Valley Authority		No
Exelon		PRC-004 - suggest that the Standard state that responsibility for the analysis of missoperations of protective equipment shall be the responsibility of the owner of the protective equipment.
<p><b>Response:</b> Thank you for your comment and support. The SDT believes that the language makes clear that an entity need only be concerned with the Elements or Facilities that it owns.</p>		
ReliabiltyFirst		ReliabilityFist has found a number of editorrial erros for the FAC-001-1 VSLs. They include the following:1. VSL R1 - should not reference sub-requirements, should reference the sub-parts consistent with the requirement (i.e. Requirement R1, Part

Organization	Yes or No	Question 10 Comment
		1.1, 1.2 or 1.3) 2. VSL for R3 - the VSL should referenced Requirement 3, Part 3.1.1 through 3.1.16 rather than what is currently stated (Requirement R3, Part 3.1.1 R3.1.6)
<p><b>Response:</b> Thank you for your comment. While we agree that the VSLs for R1 need to be updated, that change is outside the scope of this SDT because our changes are limited to those that incorporate the GO into the applicability of the requirement; the team made no changes to R1 as it only includes the TO. We have, however, made the suggested changes to the VSLs for R3.</p>		
RES Americas Development		<p>RES and AWEA appreciates the opportunity to submit these comments on the NERC Project 2010-07. We support the general direction indicated by both the Generator Requirements at the Transmission Interface Ad Hoc Group and the Project 2010-07 Standards Development Team. We agree with the sentiments from both groups that a GO or GOP that also owns or operates a generator lead line should not be required to register as a TO or TOP strictly because they own or operate a generator lead line. We also agree that requiring these GO/GOPs to comply with all the TO/TOP standards would have little effect on or benefits to reliability of the Bulk Electric System, and could even detract from it. RES and AWEA supports the intent and goal of the SDT to ensure that all generator-owned Facilities are appropriately covered under NERC’s Reliability Standards. We also agree with the SDT that while many GO/GOPs operate Elements and Facilities that might be considered by some entities to be Transmission, these are most often radial Facilities that are not part of the integrated grid, and as such should not be subject to the same standards applicable to TO/TOPs, who own and operate Transmission Elements and Facilities that are part of the integrated grid. Therefore, we support the SDT’s approach of identifying a very limited number of TO/TOP standards, such as FAC-001 and FAC-003, which should also apply to GO/GOP owners of generator lead lines. We would be concerned, however, if additional requirements were added beyond FAC-001, FAC-003, and PRC-004. Consideration of any additional standards with respect to generator lead lines should be done on a standard-by-standard basis, reviewing the applicability of each standard as well as the impact on the reliability of the Bulk Electric System.</p>



Organization	Yes or No	Question 10 Comment
Sempra Generation		Sempra Generation also supports the comments, being concurrently filed, of the Electric Power Supply Association (EPSA).
<b>Response:</b> Thank you for your comment and support.		
Puget Sound Energy, Inc.		The changes to this standard are minor, and seem to be centered around including "generator Interconnection facilities" to R2. This added phrase and the statement in 1.4 Data Retention "Generator Owner that owns a generation Protection System" seems to assume that the generator owner and generator interconnection facilities owner is always the same. This is not always the case, and will make this standard language confusing to prepare evidence for. A suggestion would be to revise the language to allow for a separate generator owner and generator interconnection facilities owner.
<b>Response:</b> Thank you for your comment and support. The SDT believes that the language makes clear that an entity need only be concerned with the Elements or Facilities that it owns.		
SERC Planning Standards Subcommittee/ SERC OC Standards Review Group		The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers"
<b>Response:</b> Thank you for your comment and support.		

END OF REPORT

# Consideration of Comments

## Generator Requirements at the Transmission Interface Project 2010-07

On January 20, 2012, Exelon submitted a Level One Appeal of the standard process for FAC-003-3 and FAC-003-X to NERC's Vice President of Standards and Training that stated the following: "Exelon believes that the NERC Standards Process Manual was not followed, and that based on the substantive changes made to both Standards following the Initial Ballot, NERC should have set the Standards for vote using a Successive Ballot rather than a Recirculation Ballot."

NERC's Vice President of Standards and Training submitted a timely response to the appeal that found that "Exelon...made its case that the [Standard Processes Manual] was not adhered to and that a change impacting applicability was made between the last successive and recirculation ballot." Accordingly, the Vice President of Standards and Training referred the issue to the Standards Committee for handling, suggesting the following options:

1. Re-post the standard for a successive ballot and recirculation ballot. Essentially set the clock back and correctly replay the last steps of the process.
2. Ask the SDT to remove the clarification language from the final standard and go directly to recirculation ballot.
3. Ask the SDT to redesign the challenged portion of the proposed standard.

He recommended that the Standards Committee pursue option 2. In a Standards Committee Executive Committee (SCEC) conference call on February 23, 2012, the SCEC directed NERC staff to void the FAC-003-3 and FAC-003-X recirculation ballot results of December 2011 and "remand the work to the drafting team with direction to take into account the issues raised in the Exelon appeal submitted in response to the recirculation ballot previously conducted and either: modify the language added following the initial ballot and then re-post the standard for a successive ballot, or remove the language added following the initial ballot and go directly to recirculation ballot."

The Project 2010-07 SDT considered Exelon's appeal in the context of other stakeholder comments submitted in the first successive ballot between October 5 and November 18, 2011. The SDT continues to believe that a reference to line of sight is clarifying.

With this line of sight reference, the SDT simply seeks to clarify the exception language based on the intent that has been agreed upon by the stakeholder body. In its Consideration of Comments report from the last formal comment period, which ended on July 17, 2011, the SDT explained "We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting

point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor.” With the addition of an explicit line of sight reference here, the SDT believes it has clarified its original intent and appropriately considered all comments submitted.

The SDT has modified 4.3.1 to include a reference to line of sight. 4.3.1 of FAC-003-X now reads:

Generator Owner that owns an overhead transmission line(s) that (1) extends greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner’s Facility or (2) does not have a clear line of sight from the generating station switchyard fence to the point of interconnection with a Transmission Owner’s Facility and is operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.

4.3.1 of FAC-003-3 now reads:

Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner’s Facility or (2) do not have a clear line of sight from the generating station switchyard fence to the point of interconnection with a Transmission Owner’s Facility and are: Operated at 200kV or higher; or operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

Both references to clear line of sight include a footnote stating: “‘Clear line of sight’ means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.”

Additionally, “Regional Entity” has been removed from the applicability section of FAC-003-X because it is not a recognized Functional Entity.

The FAC-003-3 and FAC-003-X recirculation ballot results of December 2011 have been voided, and both standards are being posted for a 30-day concurrent comment period and successive ballot to allow stakeholders the opportunity to comment on these changes.

Members of the ballot pool should note that for this ballot, the SDT will be balloting **both** FAC-003-3 and FAC-003-X, but stakeholders should **not** vote as though they are choosing one or the other. The SDT plans to present FAC-003-3 alone to NERC’s Board of Trustees, but it wants to have FAC-003-X ready to submit to the Board if, for some reason, neither FAC-003-2 nor FAC-003-3 are approved by FERC. Members of the ballot body should vote on the merits of each version of FAC-003 individually. In

other words, stakeholders who support adding GOs to the applicability of FAC-003 should vote in the affirmative for both FAC-003-3 and FAC-003-X.

The Exelon appeal and NERC response are posted on the 2010-07 project page.

Status of other standards that are part of Project 2010-07:

- FAC-001-1 and PRC-004-2.1a were adopted by NERC’s Board of Trustees on February 9, 2012
- PRC-005-1.1a is currently posted for a 45-day concurrent comment and initial ballot.

No standards modified under Project 2010-07 will be filed with regulatory authorities until the Board of Trustees has acted on the complete package of four standards.

~~In FAC-003-X and FAC-003-3, the SDT added a clarifying reference to line of sight in the GO exemption in section 4.3.1. of both versions; corrected a typo in 4.3.1.2 of FAC-003-3; and changed “RE” to “Regional Entity” in 4.3.1 of FAC-003-X.~~

~~As it discusses in the document titled “Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface,” the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.~~

~~To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: “Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”~~

~~With this reference, the SDT simply seeks to clarify the exception language based on the intent that has been agreed upon by the stakeholder body. In its Consideration of Comments report from the last formal comment period, which ended on July 17, 2011, the SDT explained “We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor.” With the addition of an explicit line of sight reference here, the SDT believes it has clarified its original intent and appropriately considered all comments submitted.~~

~~Members of the ballot pool should note that for its recirculation ballot, the SDT will be balloting both FAC-003-3 and FAC-003-X, but stakeholders should not vote as though they are choosing one or the other. The SDT plans to present FAC-003-3 alone to NERC's Board of Trustees, but it wants to have FAC-003-X ready to submit to the Board if, for some reason, neither FAC-003-2 nor FAC-003-3 are approved by FERC. Members of the ballot body should vote on the merits of each version of FAC-003 individually. In other words, stakeholders who support adding GOs to the applicability of FAC-003 should vote in the affirmative for both FAC-003-3 and FAC-003-X.~~

While this summary has been updated to reflect the status of FAC-003-3 and FAC-003-X, the SDT's responses to stakeholder comments below have not changed, except as they relate to FAC-003-3 and FAC-003-X.

All comments submitted may be reviewed in their original format on the standard's project page:

[http://www.nerc.com/filez/standards/Project2010-07\\_GOTO\\_Project.html](http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html)

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 404-446-2560 or at [herb.schrayshuen@nerc.net](mailto:herb.schrayshuen@nerc.net). In addition, there is a NERC Reliability Standards Appeals Process.<sup>1</sup>

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<sup>1</sup> The appeals process is in the Standard Processes Manual: [http://www.nerc.com/files/Appendix\\_3A\\_Standard\\_Processes\\_Manual\\_20110825.pdf](http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf).

**Index to Questions, Comments, and Responses**

1. Based on stakeholder comment, the SDT clarified the applicability language of FAC-001-1 and removed the Generator Owner from R4. Do you support the proposed redline changes to FAC-001-1? (Please refer to the posted FAC-001-1 technical justification document for more information about the SDT’s rationale for its changes.) ..... 12

2. Do you support the one year compliance timeframe for Generator Owners as proposed in the Implementation Plan for FAC-001-1? ..... 29

3. With respect to FAC-003, many commenters focused on the half-mile qualifier in FAC-003. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: “...that extends greater than one mile beyond the fenced area of the generating station switchyard...” We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.

Taking into consideration that only one of the versions of FAC-003 will actually be implemented, a decision that will be made as Project 2007-07—Vegetation Management moves forward, do you support the proposed redline changes to FAC-003-X and FAC-003-3? ..... 34

4. Do you support compliance timeframe for Generator Owners as included and explained in the Implementation Plans for FAC-003-X? ..... 50

5. In the FAC-003-3 implementation plan, the SDT has attempted to account for a number of different scenarios that could play out with respect to the filing and approvals of FAC-003-2 and FAC-003-3. Do you support this approach? If there are other scenarios that the SDT needs to account for, please suggest them here. .... 57

6. In its technical justification document, the SDT reviews all standards that had been proposed for substantive modification in the Ad Hoc Group’s original support and explains why, with the exception of FAC-003, modifying them would not provide any reliability benefit. Do you support these justifications? If you believe the SDT needs to add more information to its rationale for any of these decisions, please include suggested language here. .... 63

7. The SDT is attempting to modify a set of standards so that radial generator interconnection Facilities are appropriately accounted for in NERC’s Reliability Standards, both to close reliability

- gaps and to prevent the unnecessary registration of GOs and GOPs at TOs and TOPs. Does the set of standards currently posted achieve this goal? ..... 74
- 8. If you answered “yes” to Question 7, are the modifications the SDT has made in this posting the appropriate ones? ..... 87
- 9. If you answered “no” to Question 7, what standards need to be added or removed to achieve the SDT’s goal? Please provide technical justification for your answer. .... 91
- 10. Do you have any other comments that you have not yet addressed? If yes, please explain. .... 99

**The Industry Segments are:**

- 1 — Transmission Owners
- 2 — RTOs, ISOs
- 3 — Load-serving Entities
- 4 — Transmission-dependent Utilities
- 5 — Electric Generators
- 6 — Electricity Brokers, Aggregators, and Marketers
- 7 — Large Electricity End Users
- 8 — Small Electricity End Users
- 9 — Federal, State, Provincial Regulatory or other Government Entities
- 10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment										
				1	2	3	4	5	6	7	8	9	10	
1.	Group	Gerald Beckerle	SERC OC Standards Review Group	X		X								
1.	Scott Brame	NCEMC	SERC 1, 3, 4, 5											
2.	Troy Willis	Georgia Transmission Corp.	SERC 1											
3.	Mike Hirst	Cogentrix	SERC 5											
4.	Bob Dalrymple	TVA	SERC 1, 3, 5, 6											
5.	Matt Carden	Southern Co.	SERC 1, 5											
6.	Shardra Scott	Gulf Power Co.	SERC 3											
7.	Kerry Sibley	Georgia Transmission Corp.	SERC 1											
8.	Andy Burch	EEL	SERC 5											
9.	Shaun Anders	City of Springfield (CWLP)	SERC 1, 3											
10.	Melinda Montgomery	Entergy	SERC 1, 3, 5											
11.	John Troha	SERC Reliability Corp	SERC 10											
2.	Group	Jonathan Hayes	Southwest Power Pool Standards Development Team		X									
<b>Additional Member</b>		<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>										



Group/Individual	Commenter	Organization	Registered Ballot Body Segment																
			1	2	3	4	5	6	7	8	9	10							
1. Jonathan Hayes	Southwest Power Pool	SPP	2																
2. Robert Rhodes	Southwest Power Pool	SPP	2																
3. Don Taylor	Westar	SPP	1, 3, 5, 6																
4. John Allen	City Utilities of Springfield	SPP	1, 4																
5. Sean Simpson	MCPBPU	SPP	1, 3, 5																
6. Louis Guidry	CLECO	SPP	1, 3, 5																
7. Mitch Williams	Western Farmers	SPP	1, 3, 5																
8. Valerie Pinnamonti	AEP	SPP	1, 3, 5																
9. Bud Averill	Grand River Dam Authority	SPP	1, 3, 5																
10. Terri Pyle	OGE	SPP	1, 3, 5																
3.	Group	Guy Zito, Guy Zito	Northeast Power Coordinating Council, Northeast Power Coordinating Council																X
	<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>															
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC, NPCC	10															
2.	Greg Campoli	New York Independent System Operator	NPCC, NPCC	2															
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC, NPCC	1															
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC, NPCC	1															
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC, NPCC	10															
6.	Brian Evans-Mongeon	Utility Services	NPCC, NPCC	8															
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC, NPCC	5															
8.	Kathleen Goodman	ISO - New England	NPCC, NPCC	2															
9.	Chantel Haswell	FPL Group, Inc.	NPCC, NPCC	5															
10.	David Kiguel	Hydro One Networks Inc.	NPCC, NPCC	1															
11.	Michael R. Lombardi	Northeast Utilities	NPCC, NPCC	1															
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC, NPCC	9															
13.	Bruce Metruck	New York Power Authority	NPCC, NPCC	6															
14.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC, NPCC	10															
15.	Robert Pellegrini	The United Illuminating Company	NPCC, NPCC	1															
16.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC, NPCC	1															
17.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC, NPCC	5															
18.	Saurabh Saksena	National Grid	NPCC, NPCC	1															
19.	Michael Schiavone	National Grid	NPCC, NPCC	1															

Group/Individual	Commenter	Organization	Registered Ballot Body Segment											
			1	2	3	4	5	6	7	8	9	10		
20. Wayne Sipperly	New York Power Authority	NPCC, NPCC 5												
21. Tina Teng	Independent Electricity System Operator	NPCC, NPCC 2												
22. Donald Weaver	New Brunswick System Operator	NPCC, NPCC 2												
23. Ben Wu	Orange and Rockland Utilities	NPCC, NPCC 1												
24. Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC, NPCC 3												
4. Group	Emily Pannel	Southwest Power Pool Regional Entity												X
No additional members listed.														
5. Group	Will SMith	MRO NSRF	X	X	X	X	X	X	X	X				X
<b>Additional Member Additional Organization Region Segment Selection</b>														
1.	Mahmood Safi	OPPD	MRO	1, 3, 5, 6										
2.	Chuck Lawrence	ATC	MRO	1										
3.	Jodi Jenson	WAPA	MRO	1, 6										
4.	Ken Goldsmith	ALTW	MRO	4										
5.	Alice Ireland	XCEL/NSP	MRO	1, 3, 5, 6										
6.	Dave Rudolph	BEPC	MRO	1, 3, 5, 6										
7.	Eric Ruskamp	LES	MRO	1, 3, 5, 6										
8.	Joe DePoorter	MGE	MRO	3, 4, 5, 6										
9.	Scott Nickels	RPU	MRO	4										
10.	Terry Harbour	MEC	MRO	1, 3, 5, 6										
11.	Marie Knox	MISO	MRO	2										
12.	Lee Kittelson	OTP	MRO	1, 3, 4, 5										
13.	Scott Bos	MPW	MRO	1, 3, 5, 6										
14.	Tony Eddleman	NPPD	MRO	1, 3, 5										
15.	Mike Brytowski	GRE	MRO	1, 3, 5, 6										
16.	Richard Burt	MPC	MRO	1, 3, 5, 6										
6. Group	Charles W. Long	SERC Planning Standards Subcommittee	X											X
<b>Additional Member Additional Organization Region Segment Selection</b>														
1.	Pat Huntley	SERC	SERC	10										
2.	John Sullivan	Ameren Services Co.	SERC	1										
3.	Philip Kleckley	SC Electric & Gas Co.	SERC	1										
4.	Bob Jones	Southern Company Services	SERC	1										

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
5.	Jason Adams	TVA	SERC 1										
7.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				
<b>Additional Member Additional Organization Region Segment Selection</b>													
1.	Timothy Beyrle	City of New Smyrna Beach	FRCC 4										
2.	Greg Woessner	Kissimmee Utility Authority	FRCC 3										
3.	Jim Howard	Lakeland Electric	FRCC 3										
4.	Lynne Mila	City of Clewiston	FRCC 3										
5.	Joe Stonecipher	Beaches Energy Services	FRCC 1										
6.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC 4										
7.	Randy Hahn	Ocala Utility Services	FRCC 3										
8.	Group	Mike Garton	Dominion	X		X		X	X				
<b>Additional Member Additional Organization Region Segment Selection</b>													
1.	Michael Gildea	Dominion Resources Services, Inc.	RFC 5, 6										
2.	Connie Lowe	Dominion Resources Services, Inc.	NPCC 5, 6										
3.	Michael Crowley	Virginia Electric and Power Company	RFC 1, 3										
9.	Group	Annette M. Bannon	PPL NERC Registered Affiliates			X		X	X				
<b>Additional Member Additional Organization Region Segment Selection</b>													
1.	Brent Ingebrigston	LG&E and KU Services Co.	SERC 3										
2.	Don Lock	PPL Brunner Island, LLC	RFC 5										
3.		PPL Martins Creek, LLC	RFC 5										
4.		PPL Holtwood, LLC	RFC 5										
5.		PPL Montour, LLC	RFC 5										
6.		Lower Mount Bethel Energy, LLC	RFC 5										
7.	Annete Bannon	PPL Susquehanna, LLC	RFC 5										
8.	Leland McMillan	PPL Montana, LLC	WECC 5										
10.	Group	Jason Marshall	ACES Power Marketing Standards Collaborators										
<b>Additional Member Additional Organization Region Segment Selection</b>													
1.	Mohan Sachdeva	Buckeye Power	RFC 3, 5, 6										
2.	Erin Woods	East Kentucky Power Cooperative	SERC 1, 3, 5, 6										
3.	Michael Brytowski	Great River Energy	MRO 1, 3, 5, 6										

Group/Individual		Commenter	Organization	Registered Ballot Body Segment											
				1	2	3	4	5	6	7	8	9	10		
11.	Group	Steve Rueckert	Western Electricity Coordinating Council												X
No additional members listed.															
12.	Individual	Jack Cashin	Electric Power Supply Association					X	X						
13.	Individual	Natalie McIntire	American Wind Energy Association					X							
14.	Individual	Tom Flynn	Puget Sound Energy, Inc.	X				X	X						
15.	Individual	Silvia Parada Mitchell	Compliance & Responsibility Organization	X		X		X	X						
16.	Individual	Antonio Grayson	Southern Company	X		X		X	X						
17.	Individual	Chris Higgins/Stephen Enyeart/Chuck Mathews/Charles Sheppard	Bonneville Power Administration	X		X		X	X						
18.	Individual	Thad Ness	American Electric Power	X		X		X	X						
19.	Individual	Carla Bayer	BP Wind Energy North America Inc.					X							
20.	Individual	John Bee on behalf of Exelon	Exelon	X				X							
21.	Individual	Dennis Sismaet	Seattle City Light	X		X	X	X	X						
22.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP (Occidental Chemical)					X							
23.	Individual	Michael Falvo	Independent Electricity System Operator		X										
24.	Individual	Greg Rowland	Duke Energy	X		X		X	X						
25.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X											
26.	Individual	Kirit Shah	Ameren	X		X		X	X						
27.	Individual	John Seelke	PSEG	X		X		X	X						
28.	Individual	Andrew Z. Pusztai	American Transmission Company	X											
29.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X						
30.	Individual	Ravi Bantu	RES Americas Development					X							
31.	Individual	Katy Wilson	Sempra Generation					X							

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
32.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
33.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
34.	Individual	Ed Davis	Entergy Services	X		X		X	X				
35.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
36.	Individual	Russell A. Noble	Cowlitz County PUD			X	X	X					
37.	Individual	Anthony Jablonski	ReliabiltyFirst										X
38.	Individual	Donald Jones	Texas Reliability Entity										X
39.	Individual	Amir Hammad	Constellation Power Source Generation					X					
40.	Individual	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

1. **Based on stakeholder comment, the SDT clarified the applicability language of FAC-001-1 and removed the Generator Owner from R4. Do you support the proposed redline changes to FAC-001-1? (Please refer to the posted FAC-001-1 technical justification document for more information about the SDT’s rationale for its changes.)**

#### Summary Consideration:

The SDT thanks all stakeholders for their comments and their 87% approval for the FAC-001-1 changes posted for ballot in November 2011. Based on stakeholder feedback, the SDT has made the following minor changes to FAC-001-1:

-Corrected a typo in Applicability section 4.2.1 to change “within” to “with.”

-Corrected a typo in the VSLs for R3 to ensure that parts 3.1.1 through 3.1.16 were referenced, rather than just 3.1.1 through 3.1.6.

-Changed references to “Transmission System” to “interconnected Transmission systems” to ensure consistency with the language elsewhere in the standard and in FAC-002-1.

Some stakeholders remain concerned about the intent of the SDT’s work on FAC-001-1. The SDT reminded them that the scope is addressed in the SAR. The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT determined that it should first address “low-hanging fruit” and believes these to be sole-use Facilities (see posted examples under “Supporting Materials”) – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP). Through its deliberations, the SDT concluded that an interconnection Facility owned or operated by a GO or GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT.

Concerned commenters were also referred to one of the SDT’s resource documents: [Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document](#).

Some commenters suggested changes to Requirements R1 or R4, which deal exclusively with the Transmission Operator and are outside the scope of the SDT’s work.

One commenter suggested formatting changes. The SDT agrees with the commenter that there are a number of ways to format the standard with this SDT’s revisions. However, the majority of stakeholders support the current format of the standard and no change was made.

One commenter suggested that the phrase “Generator Owner’s existing Facility” be changed to “Generator Owner’s existing Transmission Facility.” The SDT does not agree with labeling a GO’s Facility as “Transmission,” in part because in

some areas (like Texas), GOs, by statute, can't own Transmission. It was also brought to the SDT's attention that in most cases, the Facility in question is referred to as the Interconnection Facility in documents filed by the GO with FERC. Therefore, the SDT intentionally modified language so that a Facility owned by a generation entity did not contain the term "Transmission."

One commenter did not agree with the overall clarifying change to the Applicability section, but the SDT reminded this commenter that this change was made to address previous comments that indicated that there was uncertainty as to whether "another Facility to its existing generation Facility" was meant to address connecting additional generators by the same GO. The SDT intends FAC-001-1 to apply only when the GO of an existing Facility executes an agreement to evaluate the reliability impact of connecting additional generation owned by another GO. No change made with respect to this comment.

A few stakeholders were concerned with the 45-day time frame included in the standard. The SDT pointed out that majority of stakeholders and the SDT support 45 days as a sufficient time frame because in many cases, the GO would simply need to adopt (document and publish) the Facility connection requirements of its TO. No change to that time frame was made.

Organization	Yes or No	Question 1 Comment
Manitoba Hydro	Negative	The intention of the NERC SDT in revising these standards is not clear. While the Technical Justification document states that the SDT intended to focus on a Generator Owner's radial interconnection facilities, the scope of the revised standard (s) is not confined to such facilities. The very broadly defined term "Facility" is used. Moreover, the Technical Justification document's reference to the FERC decision in Cedar Creek as a basis for the revision of additional standards is confusing, since that decision did not specifically address the issue of radial facilities and supported NERC's registration of GOs as TOs.
<p><b>Response:</b> Thank you for your comment. The scope of this SDT is addressed in the <a href="#">SAR</a>. The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT determined that it should first address "low-hanging fruit" and believes these to be sole-use Facilities (see posted examples under "Supporting Materials") – that is, a Facility used to connect one or more generators to a Facility owned or operated by a</p>		

Organization	Yes or No	Question 1 Comment
<p>transmission entity (TO/TOP). Through our deliberations, we came to the conclusion that an interconnection Facility owned or operated by a GO or GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT.</p> <p>The SDT also refers the commenter to the document titled <a href="#">Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document</a>. Specifically, see the last paragraph on page 4 and first two on page 5.</p>		
Southern Company	No	<p>1) R4 is duplicative of R1 - either remove "maintain" from R1 or delete R4 - both instances of "maintain" are not needed.â€¢ 2) The measures, as written, provide no additional indication of the evidence that could be presented to demonstrate compliance with the Reliability Standard Requirements. They provide little guidance on assessing non-compliance with the Requirements. â€¢</p>
<p><b>Response:</b> Thank you for your comment. We agree with your suggestions, but both are outside the scope of this SDT. These items will be submitted to the Issues Database to be addressed in a future revision of FAC-001.</p>		
Southwest Power Pool Standards Development Team	No	<p>Based on the applicability section of FAC-001 we feel that the strike through should have been kept. It limited the requirement to just those generator owners who had agreements in place, which we feel is appropriate.</p>
<p><b>Response:</b> Thank you for your comment. This change was made to address previous comments that indicated to the SDT there was uncertainty as to whether this was meant to address connecting additional generators by the same GO. The SDT intends FAC-001 to apply only when the GO of an existing Facility executes an agreement to evaluate the reliability impact of connecting additional generation owned by another GO. No change made with respect to this comment.</p>		
Texas Reliability Entity	No	<p>In Section 5.1, the reference to Regional Entity should be removed. There are no requirements that apply to the Regional Entity.</p> <p>In Requirements R1 and R4, "Planning Coordinator" should be added after "Regional Entity." In the ERCOT Region it is the Planning Coordinator that maintains planning criteria and connection requirements. There is no NERC</p>



Organization	Yes or No	Question 1 Comment
		<p>requirement or any obligation (as indicated in the technical justification document) on the part of a GO to specifically execute an Agreement to evaluate the reliability impact of interconnecting a third party Facility. Therefore, this requirement’s applicability is contingent on a prerequisite that may not occur, and that is under the control of the GO. This assumption on the part of the SDT unnecessarily complicates the compliance monitoring and enforcement of this standard. For instance, if an “Agreement” is not executed, a GO is not required to comply with the requirement, even though the GO may ultimately interconnect with another entity. The requirement should be modified to include an applicability trigger similar to that of FAC-002-1, so that once a GO “seek[s] to integrate . . .,” i.e., agrees to or is compelled to allow a third-party interconnection, then the requirement becomes applicable. Otherwise, the compliance and monitoring is subject to the SDT’s speculation as indicated in this language included in the technical justification document: “However, the SDT cannot be certain this is the only example and it therefore proposes to add this new requirement to FAC-001-1. In doing so, the SDT acknowledges that the Generator Owner may not, at the time it agrees or is compelled to allow a third party to interconnect, have the necessary expertise to conduct the required interconnect studies to meet this standard. Assuming that a regulatory body would require a Generator Owner to evaluate such an interconnection request, the SDT expects the Generator Owner and the third party to execute some form of an Agreement.”</p>
<p><b>Response:</b> Thank you for your comment. All of these comments are outside the scope of the <a href="#">SAR</a> and the SDT’s work because they refer specifically to the sections and requirements that apply to the TO alone. We encourage you to consider submitting a SAR that addresses your concerns.</p>		
Manitoba Hydro	No	<p>Manitoba Hydro has the following comments:</p> <ol style="list-style-type: none"> <li>1) The intention of the NERC SDT in revising these standards is not clear.</li> </ol>

Organization	Yes or No	Question 1 Comment
		<p>While the Technical Justification document states that the SDT intended to focus on a Generator Owner’s radial interconnection facilities, the scope of the revised standard (s) is not confined to such facilities. The very broadly defined term “Facility” is used. Moreover, the Technical Justification document’s reference to the FERC decision in Cedar Creek as a basis for the revision of additional standards is confusing, since that decision did not specifically address the issue of radial facilities and supported NERC’s registration of GOs as TOs.</p> <p>2) If the drafting team intends to limit the scope of FAC-001-1 to GO owned radial generator interconnection facilities that are not deemed BES transmission and therefore would not require the registration of the GO as a TO, Manitoba Hydro disagrees with the proposed changes to FAC-001-1 as Generator Owners may not have the models or expertise to perform interconnection studies to determine if there is an impact on the Transmission Network. This concern is echoed in the technical justification document provided by NERC: ‘the SDT acknowledges that the Generator Owner may not, at the time it agrees or is compelled to allow a third part to interconnect, have the necessary expertise to conduct the required interconnect studies to meet this standard... the Generator Owner will have to acquire such expertise. How the Generator Owner chooses to do so is not for the SDT to determine.’ Although it may not be for the SDT to determine how a GO obtains technical expertise, ensuring that such expertise is acquired before a GO conducts the required interconnection studies should be a concern to NERC as this directly affects the reliability of the BES. As a result, all interconnection requests should be implemented by the TO providing the GO with connection to the BES regardless if the interconnection point is within a Generation Owner facility or End-User facility as the TO is in the best position to set unbiased connection requirements to ensure the reliability of the BES is maintained. If the scope of FAC-001-1 also applies to GO owned BES transmission facilities, Manitoba</p>

Organization	Yes or No	Question 1 Comment
		<p>Hydro strongly believes that the Compliance Registry should apply and the GOs should be required to register as a TO and abide by all applicable standards to that functional type. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. Reliability gaps would be better addressed if select GOs and GOPs registered as TOs and TOPs to ensure all reliability standards, including the protection standards, are met so the reliability of the BES is maintained. At this time, this would not lead to a large number of extra registrations since, as stated in the technical justification document, ‘interconnection requests for Generator Owner Facilities are still relatively rare.</p> <p>3) If the redline changes are implemented, GOs are removed from R4, thereby removing the obligation for GOs to maintain their connection requirements. If GOs are included in FAC-001, they should be held accountable to the same level as TOs and should be required to maintain their connection requirements. Requiring a GO to maintain connection requirements would be especially beneficial to the GO themselves. In the majority of instances, any GO that is an Applicable Entity for FAC-001 would initially be inexperienced in performing interconnection studies and would benefit from regular and frequent review of their connection requirements as experience and expertise are gained.</p> <p>4) The revision to FAC-001-1 R2 may be problematic, depending on what was intended. Under the revised requirement, the obligation to comply is dependent on the execution of an agreement to evaluate reliability impacts under FAC-002-1. However, FAC-002-1 does not clearly require the execution of an agreement by the Generator Owner. FAC-002-1 only requires the Generator Owner to “coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority”. Accordingly if a Generator Owner coordinates without executing an agreement to perform an assessment, compliance with FAC-001 R1 will not</p>

Organization	Yes or No	Question 1 Comment
		<p>be required.</p> <p>5) Manitoba Hydro would also like to point out that if the redline changes are implemented, it will greatly increase the complexity of coordination required under FAC-002-1 for Transmission Planners/Planning Authorities.</p>
<p><b>Response:</b> Thank you for your comment. The scope of this SDT is addressed in the <a href="#">SAR</a>. The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP).</p> <p>The intent of the modifications to this standard is to address the requirements of the GO prior to the interconnection of the third party to their Facilities. The reliability gap the SDT intends to close is the need for the GO to develop Facility connection requirements prior to interconnection. The SDT does agree that upon interconnection of a third party, other standards or registrations may apply as appropriate.</p> <p>The SDT also refers the commenter to the document titled <a href="#">Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document</a>, which is posted on the project page. Specifically, see the last paragraph on page 4 and first two on page 5.</p>		
Tennessee Valley Authority	No	<p>Suggest that the overall structure of the standard be revised such that R1 - R3 are applicable to the Transmission Owner (consistent with existing FAC-001-0) and R4 (the new requirement) is applicable to the “applicable Generator Owner”. See further comments below. Support the proposed revisions to R1 and R4, but suggest R4 be returned to R3 (consistent with existing FAC-001-0).R3 in the balloted standard should be returned to R2 (consistent with existing FAC-001-0) and only be applicable to the Transmission Owner. R3.1 (or R2.1 if moved back) should be “fixed”, but it may be beyond this SDT’s charge. The use of “above” in the FAC-001-0 standard, or the proposed reference to “Requirements R1 or R2” in the proposed standard do not make sense in combination with the colon used at the end of the requirement. Suggest that R3.1 (or 2.1 if moved back) be revised as written below and all sub-requirements of R3.1 be elevated (R3.1.1 becomes R3.2, R3.1.2 becomes R3.3, etc.).”R3.1 Performance</p>

Organization	Yes or No	Question 1 Comment
		<p>requirements and/or planning criteria used to assess system impacts.” R2 in the balloted standard should become R4 and modified to incorporate the connection requirements contained in R3 that can more reasonably be expected of an “applicable Generator Owner”. For instance, an “applicable Generator Owner” might simply have a connection requirement for a third party that addresses coordination of system impact studies with the appropriate Transmission Owner(s), in lieu of R3.1, R3.1.1, and R3.1.2. Suggest that R2 (or R4 if moved below existing FAC-001-0 requirements) be revised as written below.”R2 Each applicable Generator Owner that has agreed to allow a third party Facility owner (Generation Facility, Transmission Facility, or End-user Facility) to connect to the Transmission system through use of pre-existing applicable Generator Owner Facilities shall communicate it’s Facility connection requirements to the third party. The applicable Generator Owner Facility connection requirements shall address the following items: R2.1 Coordination of system impact studies with the Transmission Owner. R2.2 Voltage level and MW and MVAR capacity or demand at point of connection. R2.3 Breaker duty and surge protection. R2.4 System protection and coordination R2.5 Metering....” Etc.</p>
<p><b>Response:</b> Thank you for your comment. We gave the comment due consideration and agree that there are a number of ways to format the standard with this SDT’s revisions. However, the majority of stakeholders support the current format of the standard. No change made.</p>		
<p>Northeast Power Coordinating Council, Northeast Power Coordinating Council</p>	<p>No</p>	<p>The intent of the draft language in FAC-001-1 is to provide guidance for addressing the alleged reliability gap that exists between GO/GOPs that own/ operate transmission facilities but are not registered as TO/TOPs. The impact of the revised language will depend on the characterization of the generator lead after the “third party “ connects to the existing generator lead. IF the generator lead is owned by the TO utility after the third party connection : The proposed DRAFT FAC-001 language suggests that within 45 days of a 3rd party having an executed Agreement to evaluate the reliability</p>

Organization	Yes or No	Question 1 Comment
		<p>impact of interconnecting, the existing generator needs to document and publish facility connection requirements. The proposed language suggests that a third party can commandeer existing generators leads and interconnect. A reclassification would be required because “third party” power would flow through the downstream portions of the existing leads. This introduces significant challenges for defining ownership / transfer of installed assets as well as real property, easements, operational jurisdiction, O&amp;M cost responsibility, etc. The FERC approved pro-forma Attachment X Interconnection Agreement clearly states that the project Developer must meet all Applicable Reliability Standards which means that all requirements and guidelines of the Applicable Reliability Councils, and the Transmission District to which the Developer’s Large Generating Facility is directly interconnected. As an example, to accommodate this NERC proposal, the FERC approved NYISO pro-forma tariff would need to be revised to allow this “third party” use. The pro-forma interconnection tariff also states that the Developer must provide updated project information prior to the Facilities Study. The Facilities Study might not be made until several years after the Interconnection Request /Feasibility Study is made (“executed Agreement to evaluate the reliability impact of interconnecting” in this proposed draft is akin to the Interconnection Request/Feasibility Study). Placing the requirement to have the existing Generator Owner publish reliability requirements for a potential “third party user”, without the generator having any knowledge of the potential reliability outcomes or asset transfer / ownership issues is not a reasonable expectation. The interconnection of a third party to an existing generator lead would force existing generators to revise their Interconnection Agreements with FERC. The “third party”, would at a minimum, need to comply with the existing Generators reliability obligations as specified in the Interconnection Agreement. IF the third party connects to the GO owned generator lead, the GO will be considered a TO:A TO would not be involved, other than review</p>

Organization	Yes or No	Question 1 Comment
		<p>of the SRIS and Facilities reports. The difficult thing for an existing GO would be to prepare, within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility, a document listing the requirements. To allow for the above possibilities, the language for applicability of FAC-001 to GO’s or GOP’s, should be :”Each applicable Generator Owner shall, at least 60 days prior to execution of a Facilities / Class Year Study Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the Transmission System, document and publish its Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, sub regional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements.”</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees with many of the comments (as indicated in the accompanying resource document titled <a href="#">Technical Justification: FAC-001-1</a>), especially those concerning the complexities of this process. The majority of stakeholders and the SDT support 45 days as a sufficient time frame because in many cases, the GO would simply need to adopt (document and publish) the facility connection requirements of its TO. No change made.</p>		
<p>Consolidated Edison Co. of NY, Inc.</p>	<p>No</p>	<p>The language for FAC-001 Requirement R2 should be:”This requirement shall apply to each applicable Generator Owner. Generator Owner filings must be made at least 60 days in advance of execution of the final interconnection study agreement in the Planning Coordinator’s or Transmission Planner’s study process.Each applicable Generation Owner must publish its Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, sub regional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements.The evaluation of the reliability impact(s) of interconnecting a third party Facility to the Generator Owner’s existing Facility utilized for interconnection to the Transmission System must be</p>

Organization	Yes or No	Question 1 Comment
		documented.”
<p><b>Response:</b> Thank you for your comment. The SDT agrees with many of the comments (as indicated in the accompanying resource document titled <a href="#">Technical Justification: FAC-001-1</a>), especially those concerning the complexities of this process. The majority of stakeholders and the SDT support 45 days as a sufficient time frame because in many cases, the GO would simply need to adopt (document and publish) the facility connection requirements of its TO. No change made.</p>		
<p>Ingleside Cogeneration LP (Occidental Chemical)</p>	<p>No</p>	<p>Unfortunately, the vital point of this requirement revolves around whether or not a Generator Owner is compelled externally to allow access to their interconnection facilities. If the GO is driving the connection for financial or other business reasons, there is no reason they should not be responsible for developing AND maintaining a facility connection requirements document. Otherwise, when the local transmission system requirements change for any reason, there will be no entity responsible to ensure that the third party will conform as well. Conversely, if the GO should be compelled to allow access to a third party, it is the responsibility of the “compeller” to handle all the related reliability studies and documents. This may include the development of a CFR which separates reliability tasks between the GO and other entities - especially if a TSP registration is required. This ensures that the Regional Entity, PUC, RTO, or other regulator must budget dollars and resources directly related to their action - not cause them to be directed to a GO.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees with many of the comments (as indicated in the accompanying resource document titled <a href="#">Technical Justification: FAC-001-1</a>), especially those concerning the complexities of this process. However, the issues you raise are beyond the scope of the SDT and its SAR. No change made.</p>		
<p>PSEG</p>	<p>No</p>	<p>We revised this partial sentence to the following: “Each applicable Generator Owner shall, within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Transmission Facility that is used for connection</p>



Organization	Yes or No	Question 1 Comment
		<p>to the interconnected Transmission systems (under FAC-002-1), ..."- The phrase "Generator Owner's existing Facility that is used to interconnect to the Transmission System" was changed to "Generator Owner's existing Transmission Facility that is used for connection to the interconnected Transmission systems." - "Transmission" was added before Facility to exclude connections elsewhere; "Transmission System" was changed to "Transmission systems" because while "Transmission" and "System" are defined in the NERC Glossary, "System" means "A combination of generation, transmission, and distribution components." "Transmission systems" do not have generation or distribution components, so a lower case "system" is warranted. - In addition, the suggested phrase "interconnected Transmission systems" (plural "systems") uses identical language from FAC-002-1, except that we capitalized "Transmission.</p>
<p><b>Response:</b> Thank you for your comment. The SDT has addressed the proposed change to applicability according to your comments. The applicability section now reads: "Generator Owner with an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems.</p> <p>The SDT has been informed that in some areas (like Texas), GOs, by statute, can't own Transmission. It was also brought to the SDT's attention that in most cases, the Facility in question is referred to as the Interconnection Facility in documents filed by the GO with FERC. Therefore, the SDT intentionally modified language so that a Facility owned by a generation entity did not contain the term "Transmission."</p>		
Seattle City Light	Affirmative	Key points are that (1) an executed agreement is required before evaluations of impacts are necessary and (2) this only applies when a third party is connecting to the generating interconnection line.
<p><b>Response:</b> Thank you for your comment.</p>		
Electric Power Supply Association	Yes	All TO requirements for FAC-001-1 would apply if and when GO executes an Agreement to evaluate the reliability impact of interconnecting a third

Organization	Yes or No	Question 1 Comment
		<p>party Facility to its existing generation interconnection Facility. The execution of the agreement is necessary to comply with FAC-002-1 and start the compliance clock with the applicable regulatory authority. Thus as the Project 2010-07 Standard Drafting Team (SDT) in its technical justification has stated, “If, and only if, the existing owner of a generator interconnection Facility has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to its existing generation Facility” then FAC-001-1 should apply. EPSA concurs with SDT’s conclusion. The SDT has examined the issue regarding if future requests for transmission service on the interconnection Facility and in doing so acknowledged that when that Facility adopted open access and was providing transmission service it would necessitate re-evaluation of the need for the Facility to be maintained in accordance with FAC-001-1, Requirements 2 and 4. This service would indeed prompt the necessary agreement the SDT contemplates in its technical justification of FAC-001-1. EPSA believes this serves as the necessary trigger for evaluation of Requirements 2 and 4 under FAC-001-1 for GOs.</p>
<p><b>Response:</b> Thank you for your comment.</p>		
<p>American Wind Energy Association</p>	<p>Yes</p>	<p>AWEA appreciates that this standard specifies that it has limited applicability. For instance, only those generators that have an executed agreement with a third party wishing to interconnect must document and publish Facility connection requirements. We believe the proposed 45-day time window is a minimum for GO/GOP owners of generator lead lines to provide this documentation following execution of such an agreement. Anything less than 45 days could result in a burdensome and hard to meet deadline for GO/GOP staff. However, AWEA believes that extending this time window for publishing Facility connection requirements to 90 days after an executed agreement would be beneficial. We believe this will allow the GO/GOP owners of generator leads more time to coordinate with their</p>

Organization	Yes or No	Question 1 Comment
		interconnecting Transmission Providers and will result in more reliable and coordinated connection requirements for the generator lead.
<p><b>Response:</b> Thank you for your comment. The majority of stakeholders and the SDT support 45 days as a sufficient time frame because in many cases, the GO would simply need to adopt (document and publish) the facility connection requirements of its TO. No change made.</p>		
SERC OC Standards Review Group	Yes	Please verify within the applicability section (4.2.1) you intended to use the word “within” rather than some other wording.
<p><b>Response:</b> Thank you for your comment. The SDT intended it to read “Generator Owner <b>with</b> an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the Transmission System.” This change has been made.</p>		
RES Americas Development	Yes	RES Americas and AWEA appreciate that this standard specifies that it has limited applicability. For instance, only those generators that have an executed agreement with a third party wishing to interconnect must document and publish Facility connection requirements. We believe the proposed 45-day time window is a minimum for GO/GOP owners of generator lead lines to provide this documentation following execution of such an agreement. Anything less than 45 days could result in a burdensome and hard to meet deadline for GO/GOP staff. However, we believes that extending this time window for publishing Facility connection requirements to 90 days after an executed agreement would be beneficial. We believe this will allow the GO/GOP owners of generator leads more time to coordinate with their interconnecting Transmission Providers and will result in more reliable and coordinated connection requirements for the generator lead.
<p><b>Response:</b> Thank you for your comment. The majority of stakeholders and the SDT support 45 days as a sufficient time frame because in many cases, the GO would simply need to adopt (document and publish) the facility connection requirements of its TO</p>		

Organization	Yes or No	Question 1 Comment
No change made.		
ACES Power Marketing Standards Collaborators	Yes	We largely agree with the changes the drafting team made but believe some additional changes are necessary. In section 4.2.1 of the Applicability Section, “within” should be “with”. Because NERC’s Glossary of Terms establishes that an Agreement can be verbal and not enforceable by law, section 4.2.1 should be further modified to clarify that it is a legally enforceable and fully executed Agreement. The language in R3 in parenthesis after Generation Owner should be modified to “once required by Requirement R2”. This makes it clearer that R3 does not apply until the GO has an executed Agreement to evaluate a request by a third part to interconnect.
<p><b>Response:</b> Thank you for your comment. We agree that “within” should be “with”. The SDT chose not to adopt the second recommendation as the requirement already contains the term “executed.” The SDT also chose not to adopt the third recommendation as the requirement already contains the parenthetical (in accordance with Requirement R2) which we feel is synonymous with the comment.</p>		
Southwest Power Pool Regional Entity	Yes	
MRO NSRF	Yes	
SERC Planning Standards Subcommittee	Yes	
Florida Municipal Power Agency	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	

Organization	Yes or No	Question 1 Comment
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Exelon	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
Ameren	Yes	
American Transmission Company	Yes	
South Carolina Electric and Gas	Yes	
Sempra Generation	Yes	
Xcel Energy	Yes	
Cowlitz County PUD	Yes	
Constellation Power Source Generation	Yes	
ReliabilityFirst		
Entergy Services		

Organization	Yes or No	Question 1 Comment
Western Electricity Coordinating Council		
Puget Sound Energy, Inc.		
Compliance & Responsibility Organization		
Bonneville Power Administration		

**2. Do you support the one year compliance timeframe for Generator Owners as proposed in the Implementation Plan for FAC-001-1?**

**Summary Consideration:**

The vast majority of commenters supported the one year compliance time frame in the Implementation Plan. A few commenters were concerned with this time frame and associated enforcement, in part based on similar issues addressed in recent CANs. The SDT did its best to clarify its intent as follows:

The SDT’s intent is that the mandatory date (the date upon which the GO must be compliant with applicable requirements and measures) be the first calendar day of the first calendar quarter one year after FAC-001-1’s approval. The SDT believes one year is sufficient time for the GO to become compliant where it has one or more in-place (which we interpret as synonymous with legacy or grandfathered) executed Agreement(s). If an Agreement is executed after the mandatory date, then the GO has 45 days to “document and publish its Facility connection requirements” (R2) and those requirements shall address items under R3.

No changes were made to the Implementation Plan.

Organization	Yes or No	Question 2 Comment
Ingleside Cogeneration LP (Occidental Chemical)	No	Based upon similar issues addressed in Compliance Application Notices (CANs), the drafting team needs to specify how the requirements apply to an in-place “executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the Transmission System.” In the view of Ingleside Cogeneration LP, if the Agreement takes effect even one day before FAC-001-1 does, requirements R2 and R3 do not apply. Without this clarification, it is possible that NERC’s Compliance team will apply the requirements retroactively - with minimum industry input.
<p><b>Response:</b> Thank you for your comment. The SDT’s intent is that the mandatory date (the date upon which the GO must be compliant with applicable requirements and measures) be the first calendar day of the first calendar quarter <u>one year after its approval</u>. The SDT believes one year is sufficient time for the GO to become compliant where it has one or more in-place (which we interpret as synonymous with legacy or grandfathered) executed Agreement(s). If an Agreement is executed after the mandatory date, then the GO has 45 days to “document and publish its Facility connection requirements” (R2) and those requirements shall</p>		

Organization	Yes or No	Question 2 Comment
address items under R3.		
Southwest Power Pool Regional Entity	No	No action is required unless a GO has an executed third-party agreement. If a GO has an agreement, the standard already includes a 45-day timeframe for the GO to document and publish its facility connection requirements.
<p><b>Response:</b> Thank you for your comment. The SDT’s intent is that the mandatory date (the date upon which the GO must be compliant with applicable requirements and measures) be the first calendar day of the first calendar quarter <u>one year after its approval</u>. The SDT believes one year is sufficient time for the GO to become compliant where it has one or more in-place (which we interpret as synonymous with legacy or grandfathered) executed Agreement(s). If an Agreement is executed after the mandatory date, then the GO has 45 days to “document and publish its Facility connection requirements” (R2) and those requirements shall address items under R3.</p>		
Southern Company	No	See our response to Question 9.
<p><b>Response:</b> See the SDT’s response to Question 9.</p>		
Manitoba Hydro	No	See question 1 comments.
<p><b>Response:</b> See SDT’s response to Question 1.</p>		
Cowlitz County PUD	Yes	Cowlitz PUD (District) registered as a Transmission Owner shortly before FAC-001-0 became effective and was forced to file a Mitigation Plan in order to facilitate compliance. The District successfully completed compliance implementation and documentation in eight months. The proposed one year compliance timeframe is sufficient.
<p><b>Response:</b> Thank you for your comment and support.</p>		
Seattle City Light	Yes	The proposed changes for FAC-001-1 state a 45 day period to complete the evaluation. Not sure what the question is referring to regarding “ 1 year “?



Organization	Yes or No	Question 2 Comment
<p><b>Response:</b> Thank you for your comment. The SDT’s intent is that the mandatory date (the date upon which the GO must be compliant with applicable requirements and measures) be the first calendar day of the first calendar quarter <u>one year after its approval</u>. The SDT believes one year is sufficient time for the GO to become compliant where it has one or more in-place (which we interpret as synonymous with legacy or grandfathered) executed Agreement(s). If an Agreement is executed after the mandatory date, then the GO has 45 days to “document and publish its Facility connection requirements” (R2) and those requirements shall address items under R3.</p>		
<p>American Wind Energy Association / RES Americas Development</p>	<p>Yes</p>	<p>Yes, since there is no exigent reason why this standard needs to be put in place at once, we support the one-year compliance timeframe. We believe that it will allow generators a reasonable time to comply with the requirement.</p>
<p><b>Response:</b> Thank you for your comment and support.</p>		
<p>SERC OC Standards Review Group</p>	<p>Yes</p>	
<p>Southwest Power Pool Standards Development Team</p>	<p>Yes</p>	
<p>Northeast Power Coordinating Council, Northeast Power Coordinating Council</p>	<p>Yes</p>	
<p>MRO NSRF</p>	<p>Yes</p>	
<p>SERC Planning Standards Subcommittee</p>	<p>Yes</p>	
<p>Florida Municipal Power Agency</p>	<p>Yes</p>	

Organization	Yes or No	Question 2 Comment
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Electric Power Supply Association	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Exelon	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
Ameren	Yes	
PSEG	Yes	
American Transmission Company	Yes	

Organization	Yes or No	Question 2 Comment
South Carolina Electric and Gas	Yes	
Sempra Generation	Yes	
Xcel Energy	Yes	
Constellation Power Source Generation	Yes	
Western Electricity Coordinating Council		
Puget Sound Energy, Inc.		
Compliance & Responsibility Organization		
Bonneville Power Administration		
Consolidated Edison Co. of NY, Inc.		
Entergy Services		
ReliabilityFirst		
Texas Reliability Entity		

3. With respect to FAC-003, many commenters focused on the half-mile qualifier in FAC-003. Some commenters found the half-mile length too short, others found it too long, and still others found the choice among the starting points of the switchyard, generating station, or generating substation to be confusing. The drafting team attempted to address all of these concerns with its latest proposed standard changes. The qualifier now reads: “...that extends greater than one mile beyond the fenced area of the generating station switchyard...” We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor. Finally, we maintain that it is appropriate to include this qualifier for Generator Owners because there is a very low risk from vegetation within the line of sight, and thus the formal steps in this standard are not necessary to ensure reliability of these lines.

Taking into consideration that only one of the versions of FAC-003 will actually be implemented, a decision that will be made as Project 2007-07—Vegetation Management moves forward, do you support the proposed redline changes to FAC-003-X and FAC-003-3?

#### Summary Consideration:

The SDT thanks all stakeholders for their comments and their over 85% approval for the FAC-003-X and FAC-003-3 changes posted for ballot in November 2011. Based on stakeholder feedback, the SDT has made the following changes:

- Added a clarifying reference to line of sight in the GO exemption in section 4.3.1.
- Corrected a typo in 4.3.1.2 of FAC-003-3.
- Changed “RE” to “Regional Entity” in 4.3.1 of FAC-003-X.

As it discusses in the document titled “[Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface](#),” the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.

To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight. 4.3.1 of FAC-003-X now reads:

Generator Owner that owns an overhead transmission line(s) that (1) extends greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) does not have a clear line of sight from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and is operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.

4.3.1 of FAC-003-3 now reads:

Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) do not have a clear line of sight from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and are: Operated at 200kV or higher; or operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

Both references to clear line of sight include a footnote stating: "'Clear line of sight' means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day."

~~To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: "Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are..."~~

With this reference, the SDT simply seeks to clarify the exception language based on the intent that has been agreed upon by the stakeholder body. In its [Consideration of Comments report](#) from the last formal comment period, which ended on July 17, 2011, the SDT explained "We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor." With the addition of an explicit line of sight reference here, the SDT believes it has clarified its original intent and appropriately considered all comments submitted.

Some stakeholders suggested changes that should have been submitted when Project 2007-07 was revising FAC-003-2, because these suggestions dealt with the standard as a whole rather than the changes made by this SDT to ensure that GOs are included in the standard's applicability.

One commenter remains concerned about the scope of the SDT. The SDT reminded this commenter that its scope is addressed in the SAR and that its intent is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT also refers the commenter to the document titled Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document. Specifically, see the last paragraph on page 4 and first two on page 5.

Organization	Yes or No	Question 3 Comment
Ameren Services	Negative	<p>(a) There is no technical basis for the one mile length exemption. In fact, one could argue that a very short line, 300 feet in length, that experienced a fault from a tree at "the end of the circuit", i.e near the switchyard fence, would have much more of an impact on the BES because the fault would be limited by much less impedance.</p> <p>(b) It is also unclear in this version if a GO that owned one line that was 1.2 miles in length would have to comply for the entire length of said line, or just 0.2 miles of said line. If the GO is responsible for 1.2 miles, then that argues that the first mile is important and consequently there is no basis for ignoring the first mile on other lines. If the GO is only responsible for 0.2 miles, what is the technical basis to ignore a mile? And would it be the first mile from the switchyard that is ignored, or is the middle mile, or the last mile where it connects to the TO? Or could the GO decide? Or could the GO pick sections of the line that amount to a mile that they can ignore? This seems like something that should be addressed for compliance.</p> <p>(c) The 2 year compliance time line is far too long. There is significant industry evidence that was developed in the drafting of Version 2 that supports a one year compliance time-line for new lines. This is evidenced in Version 2. Thus there is no basis for the 2 years</p>
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled "<a href="#">Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface</a>," the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p>		

Organization	Yes or No	Question 3 Comment
<p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: <del>“Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”</del>;</p> <p>With respect to your second comment, the SDT intended for the length qualifier to be just that; if the overhead portion of a Facility exceeds the distance, <u>the entire Facility</u> is subject to the requirements of the standard.</p> <p>The SDT chose the time in the implementation plan based upon reasons it documented in the <a href="#">accompanying implementation plan</a> and also based upon comments of stakeholders.</p>		
Wisconsin Public Service Corp Electric Cooperative	Negative	R1.2 refers to an encroachment due to a fall in. This is confusing because according to the dictionary “Webster’s II” encroachment reads: “to intrude gradually”, and a ‘fall in’ is not usually gradual.
<p><b>Response:</b> Thank you for your comment. This is outside the scope of the <a href="#">SAR</a>. The SDT reviewed comments submitted as part of the <a href="#">Project 2007-07</a> effort and did not find this comment had been submitted.</p>		
Wisconsin Public Service Corp.	Negative	The concern with the proposed wording is that many generating station may not have a “generating station switchyard” as implied by the proposed wording. Often the generator leads (e.g. 20 kV) will exit the generator and connect to transformers located in transformer bays directly adjacent to the plant. From the transformers the now greater than 200 kV lines will be routed to the point of interconnect or a generating unit switchyard, possibly miles or yards away. By no one’s definitions would the transformer bays adjacent to the plant be considered a switchyard. The plant fence may be yards or hundreds of yards from the bays and on a multiple unit site, there may be a site fence or boundary, which could be comprise of fences, security patrols, or other barriers yards or miles from the transformer but enveloping the switchyard. The valid assumption made by the drafting team is that transmission lines within an area tightly controlled by the generator operator poses very little risk to the BES as a result of vegetation contact. This assumption is based on the valid observation that these areas are routinely occupied and observed by station

Organization	Yes or No	Question 3 Comment
		<p>personnel and as a result unexpected and unacceptable vegetation growth is highly unlikely because it is controlled by routine maintenance. It also correctly assumes that some distance past the controlled area is acceptable since this area would also be under near continuous observation. The problem comes in defining both a tightly controlled area and a line of site. We suggest the following: Controlled Area: A perimeter around a power plant, power plants, or switchyard which is prevents intrusion by the use of physical barriers, observation, or electronic monitoring and is routinely occupied such that unexpected and unacceptable vegetation growth would be observed and correct as a matter of routine maintenance. Line of Sight: A two kilometer distance from the controlled area perimeter.</p>
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled <a href="#">“Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface,”</a> the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: <del>“Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”</del>.</p>		
<p>Florida Reliability Coordinating Council</p>	<p>Negative</p>	<p>There is no technical justification for excluding 1 mile beyond the fence in the applicability of generators.</p>
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled <a href="#">“Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface,”</a> the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: <del>“Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from</del></p>		



Organization	Yes or No	Question 3 Comment
the switchyard fence to the point of interconnection and are...".		
Southern Company	No	<p>â€¢,All of these comments pertain to FAC-003-3:</p> <ol style="list-style-type: none"> <li>1) We suggest referring to the Implementation Plan in the Effective Date sub-section of Section A of the standard rather than repeating the content of the Implementation Plan in the standard. There exists unnecessary duplication with including the information in both places.</li> <li>2) We suggest simplifying the purpose statement to more succinctly say the intent, for example: "To maintain a reliable transmission system by managing vegetation located on transmission rights of way to minimize vegetation encroachments and thereby minimize the risk of vegetation related outages". If this change is not acceptable, at least change the phrase "preventing the risk" to "minimizing the risk".</li> <li>3) We feel that the Enforcement paragraphs between 4.3.1.3 and 5.0 seem to be out of place. Those paragraphs don't belong in this location - consider moving them to Section C. Compliance. The fourth paragraph belongs in the background section.</li> <li>4) We suggest moving the background section to Section F. "Associated Documents". It gets in the way of getting to the requirements of the standard.</li> <li>5) We suggest moving Table 2 of the "Guideline and Technical Basis" document into R1, since it seems to be the only part of the document that is enforceable. Further we suggest that the Guideline and Technical Basis document be removed from the standard. The inclusion of this document in the standard makes the standard unwieldy.</li> <li>6) We suggest reordering the words in R1 to more clearly state the requirement. Please consider this rephrasing: "For lines which are either an element of an IROL or an element of a Major WECC Transfer Path, each applicable TO and applicable GO shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) when operating within their Rating during all Rated Electrical Operating Conditions of the types shown below:..." (remainder is unchanged).</li> </ol>

Organization	Yes or No	Question 3 Comment
		<p>7) We suggest reordering the words of R2 to more clearly state the requirement. Please consider the this rephrasing: "For lines which are neither an element of an IROL nor an element of a Major WECC Transfer Path, each applicable TO and applicable GO shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) when operating within its Rating and during all Rated Electrical Operating Conditions of the types listed below:..." (remainder is unchanged).</p> <p>8) On Page 11 of the posted clean draft standard, is the reference to the previous footnote 2 correct? We recommend eliminating footnotes where possible to minimize redirections.</p> <p>9) The Rationale text-box on page 13 of the clean version of FAC-003-3 overlaps some of the text of footnote #6.   â€¢,â€¢,â€¢,</p>
<p><b>Response:</b> Thank you for your comment.</p> <p>With respect to your suggestion regarding the implementation plan, the SDT simply followed the NERC-mandated document guidelines. Making the change you suggest would deviate from that process and thus the SDT has not made it.</p> <p>With respect to comments 2-8, any standard changes that go beyond making a standard applicable to a GO or GOP are beyond the scope of this SDT. Any redline changes the SDT has made within standards were made to clarify or qualify the GO or GOP applicability. These comments would have been more appropriate to make during the comment period for Project 2007-07 Vegetation Management, the project that revised the version of FAC-003 from which this SDT is working.</p> <p>We have modified the rationale box on page 13 so that it does not overlap with the text of footnote 6.</p>		
Dominion	No	<p>Dominion suggests in FAC-003-X; 4.3.1. Regional Entity be changed to RE as listed in 4.2.1 for consistency. Also Regional Entity is used throughout the rest of the document, suggest using RE for consistency overall. Dominion suggests in FAC-003-3; 4.3.1. adding station to the following " Overhead transmission lines that extend greater than one mile or 1.609 kilometers beyond the fenced area of the generation station switchyard and are" to show consistency as it is written in FAC-003-X 4.3.1. Further, Dominion is concerned that the technical justification characterized the exclusion (i.e., one mile or 1.609 kilometers beyond the fenced area of the</p>

Organization	Yes or No	Question 3 Comment
		<p>generating station switchyard) as “approximate line of sign [sic] from a fixed point” and notes that this line of sight may be limited by local terrain. Where line of sight of the radial corridor is limited on a clear day due to terrain, the one mile exemption must be limited in distance to no more than the line of sight on a clear day beyond the fenced area.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees with your comment about the Regional Entity, but will instead use Regional Entity throughout.</p> <p>Thank you for your comment. As it discusses in the document titled <a href="#">“Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface,”</a> the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: <del>“Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”</del>.</p>		
Exelon	No	<p>FAC-003 - Exelon supports the one mile length qualifier, but feels that additional clarification is needed to determine the points of demarcation. There are too many differing physical configurations to use a “fence line” as a determination of applicability. Suggest that the tie line length be defined as “from the Generator Step up Transformer GSU to the point of interconnection between the GO and TO owned equipment.” Also suggest that the standard define what constitutes a generation station switchyard.</p>
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled <a href="#">“Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface,”</a> the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p>		

Organization	Yes or No	Question 3 Comment
<p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: <del>“Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”</del>.</p>		
<p>Ingleside Cogeneration LP (Occidental Chemical)</p>	<p>No</p>	<p>Ingleside Cogeneration LP is very concerned that the attempt to develop “bright-line” criteria to assign applicability to either version of FAC-003 is misplaced. As seen with NERC’s recent proposed directive related to Generator-Transmission interconnections, those thresholds can be arbitrarily reduced based upon regulators aversion to risk - not scientific evidence. (As it stands today, NERC has proposed any interconnection facility operating at 100 kV or higher and greater than 3 spans in length be applicable - which is even stricter than the TO thresholds in FAC-003.) This would suggest that a reliability assessment consistent with the TPL standards must be the determining factor. If the Planning Coordinator or Transmission Planner can show that the Generator-Transmission interconnection could contribute to a violation of an SOL or IROL, then a vegetation management program may be in order. Furthermore, there needs to be some level of common sense applied if a GO-TO interconnection is located in an area where vegetation clearance is never an issue. A one-size-fits-all requirement based upon vegetation growth in the sub-tropics, should not automatically apply in the desert. In our view, every dollar spent to control vegetation in an arid climate is one less dollar available to purchase advanced telemetry, AGC systems, and other items which have a far greater impact on reliability.</p>
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled <a href="#">“Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface,”</a> the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: <del>“Overhead transmission lines that extend</del></p>		

Organization	Yes or No	Question 3 Comment
<p><del>greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...".</del></p> <p>The SDT also took into consideration the stakeholder comments submitted and believes this exemption adequately addresses the reliability impact for a majority of the Facilities, while balancing the efforts necessary to support the standard from all entities.</p>		
Manitoba Hydro	No	<p>Manitoba Hydro does not support the changes being proposed in this project. If a Generator Owner is required to register as a TO, all the Requirements applicable to a TO should apply. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions.</p>
<p><b>Response:</b> Thank you for your comment. The scope of this SDT is addressed in the <a href="#">SAR</a>. The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT also refers the commenter to the document titled <a href="#">Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document</a>. Specifically, see the last paragraph on page 4 and first two on page 5.</p>		
Northeast Power Coordinating Council, Northeast Power Coordinating Council	No	<p>Suggest in FAC-003-X; 4.3.1. that Regional Entity be changed to RE as listed in 4.2.1 for consistency. Also Regional Entity is used throughout the rest of the document, suggest using RE for consistency. In FAC-003-3; 4.3.1. add station to the following: “Overhead transmission lines that extend greater than one mile or 1.609 kilometers beyond the fenced area of the generation station switchyard and are” to show consistency as it is written in FAC-003-X 4.3.1. The technical justification characterized the exclusion (i.e., one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard) as “approximate line of sight [sic] from a fixed point” and noted that this line of sight may be limited by local terrain. Where line of sight of the radial corridor is limited on a clear day due to terrain, the one mile exemption must be limited in distance to no more than the line of sight on a clear day beyond the fenced area.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees with your comment about the Regional Entity, but will instead use Regional Entity throughout.</p>		

Organization	Yes or No	Question 3 Comment
<p>Thank you for your comment. As it discusses in the document titled <a href="#">“Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface,”</a> the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: <del>“Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”</del>.</p>		
MRO NSRF	No	<p>The NSRF agrees with the drafting committees desire to eliminate arbitrary and capricious behavior of auditors and industry staff by precisely defining the point at which measurement starts for the length of transmission line. The concern the NSRF has with the proposed wording is that many generating station may not have a “generating station switchyard” as implied by the proposed wording. Often the generator leads (e.g. 20 kV) will exit the generator and connect to transformers located in transformer bays directly adjacent to the plant. From the transformers the now greater than 200 kV lines will be routed to the point of interconnect or a generating unit switchyard, possibly miles or yards away. By no one’s definitions would the transformer bays adjacent to the plant be considered a switchyard. The plant fence may be yards or hundreds of yards from the bays and on a multiple unit site, there may be a site fence or boundary, which could be comprise of fences, security patrols, or other barriers yards or miles from the transformer but enveloping the switchyard. The valid assumption made by the drafting team is that transmission lines within an area tightly controlled by the generator operator poses very little risk to the BES as a result of vegetation contact. This assumption is based on the valid observation that these areas are routinely occupied and observed by station personnel and as a result unexpected and unacceptable vegetation growth is highly unlikely because it is controlled by routine maintenance. It also correctly assumes that some distance past the controlled area is acceptable since this area would also be under near continuous observation. The problem comes in defining both a tightly</p>

Organization	Yes or No	Question 3 Comment
		<p>controlled area and a line of site. We suggest the following: Controlled Area: A perimeter around a power plant, power plants, or switchyard which is prevents intrusion by the use of physical barriers, observation, or electronic monitoring and is routinely occupied such that unexpected and unacceptable vegetation growth would be observed and correct as a matter of routine maintenance. Line of Sight: NSRF recommends a two kilometer distance from the controlled area perimeter. Our assessment is that an individual of average height would have a line of site of approximately 4 Kilometers. Therefore, we recommended a distance of 2 kilometers from the Controlled Area of the plant to provide margin. The revised applicability statement would read as follows: “Generator Owner that owns an overhead transmission line(s) that extends greater than 2.0 kilometers beyond the Controlled Area of the generating station up to the point of interconnection with a Transmission Owner’s Facility and is operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region. Furthermore we applaud the committee for using the metric system to identify the acceptable distance for this standard and urge it to remove all references to English units. We strongly suggest this drafting team and all future drafting team abandon the anachronistic English measurement system. This archaic system, based on the length of an average barley corn, should be abandon in all scientific and engineering endeavors.</p>
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled <a href="#">“Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface,”</a> the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: <del>“Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”</del>;</p>		

Organization	Yes or No	Question 3 Comment
Southwest Power Pool Standards Development Team	No	There is a possibility of some conflict with the Bulk Electric System Definition. This should be consistent with the Transmission Owner requirements if the lead is determined part of the BES.
<p><b>Response:</b> Thank you for your comment. The SDT intended this standard to be applied to Facilities of GO and TO equally, with the exception of the distance exemption for a generator interconnection Facility. The SDT also notes that FAC-003-2 (approved by the NERC’s Board of Trustees on Nov. 3, 2011) does not rely upon the BES definition to determine the facility to which this standard applies (200 kV or higher, or IROL or WECC Transfer Path).</p>		
South Carolina Electric and Gas	No	There should be no qualifying exemption to FAC-003 for Generator Owners.
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled <a href="#">“Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface,”</a> the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: <del>“Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”</del>.</p>		
SERC Planning Standards Subcommittee	No	We believe there should be no exemption for Generator Owners.
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled <a href="#">“Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface,”</a> the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: <del>“Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight</del></p>		



Organization	Yes or No	Question 3 Comment
<del>from the switchyard fence to the point of interconnection and are...".</del>		
PSEG	No	
Infigen Energy US	Affirmative	Infigen finds the DST supporting details regarding FAC-003-X to be appropriate. We support maintaining "reasonable and appropriate" risk prevention measures to minimize encroachment that could trigger vegetation-related outages.
<b>Response:</b> Thank you for your comment and support.		
Seattle City Light	Affirmative	Key points are the greater than one mile with clear statement of "...beyond the fenced area of the generating switchyard."
<b>Response:</b> Thank you for your comment and support.		
RES Americas Development / American Wind Energy Association	Yes	Applying the vegetation management requirements to only generator lead lines that extend more than "one mile beyond the fenced area of the generating station switchyard" strikes a reasonable balance among the many stakeholder positions expressed on this topic. We think that as this criterion recognizes that there is little need for a vegetation management plan for shorter lines, it should explicitly state that this is true for all such facilities with lines of that length or smaller.
<b>Response:</b> Thank you for your comment and support.		
Texas Reliability Entity	Yes	In the description of the "second effective date" in FAC-003-X there is an erroneous reference to "Requirement R3," which should be corrected to "Requirement R1."
<b>Response:</b> Thank you for your comment and support. This conforming change was made.		
Seattle City Light	Yes	Key points are the greater than one mile with clear statement of "...beyond the fenced area of the generating switchyard."

Organization	Yes or No	Question 3 Comment
<p><b>Response:</b> Thank you for your comment and support.</p>		
<p>ACES Power Marketing Standards Collaborators</p>	<p>Yes</p>	<p>We support the changes to FAC-003 suggested by the drafting team because we believe the drafting team has provided the best solution in face of a difficult problem. However, in general, we do not support registration of GOs and GOPs as TOs and TOPs or applicability of any TO/TOP requirements to the GO/GOP simply because they have a radial interconnection greater than one mile in length. While there may be some generators that own interconnecting facilities of significant length operated at a significant voltage that could impact BES reliability, we do not believe that the number of generating facilities that fit into that category is significantly large. When one considers that the majority of generators are still owned and operator by utilities that are also registered as a TO and TOP, there is only a minority subset of generators left that could be considered. NERC has the registration for this remaining set of generators and could use the data to evaluate how many of this remaining subset have interconnections owned by the generator that are substantial enough to affect reliability. It seems that NERC could determine the boundaries of this problem before registering anymore GOs and GOPs as TOs and TOPs or before applying additional requirements through this effort on the GOs and GOPs.</p>
<p><b>Response:</b> Thank you for your comment and support.</p>		
<p>SERC OC Standards Review Group</p>	<p>Yes</p>	
<p>Southwest Power Pool Regional Entity</p>	<p>Yes</p>	
<p>Florida Municipal Power Agency</p>	<p>Yes</p>	

Organization	Yes or No	Question 3 Comment
PPL NERC Registered Affiliates	Yes	
Electric Power Supply Association	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
American Transmission Company	Yes	
Sempra Generation	Yes	
Entergy Services	Yes	
Xcel Energy	Yes	
Cowlitz County PUD	Yes	
Constellation Power Source Generation	Yes	

Organization	Yes or No	Question 3 Comment
Western Electricity Coordinating Council		
Puget Sound Energy, Inc.		
Compliance & Responsibility Organization		
Bonneville Power Administration		
Consolidated Edison Co. of NY, Inc.		
ReliabilityFirst		
Tennessee Valley Authority		

**4. Do you support compliance timeframe for Generator Owners as included and explained in the Implementation Plans for FAC-003-X?**

**Summary Consideration:**

The SDT thanks all stakeholders for their comments. The vast majority of stakeholders support the compliance timeframes as proposed and explained in the Implementation Plan for FAC-003-X.

One commenter found a typo in the effective dates section of FAC-003-X, where one section referenced R3 when it should have referenced R1. That has been corrected in both the standard and the Implementation Plan.

A few stakeholders thought that two years was too long for an Implementation Plan for this standard. The SDT reminded those commenters that the time frame was based on previous stakeholder comments and the fact that the Implementation Plan for Version 0 standards stated “the Version 0 Reliability Standards are generally a translation and clarification of existing operating policies and planning standards, entities that are in compliance with NERC policies and standards today are expected to be able to remain in compliance with the Version 0 Reliability Standards with their existing procedures, tools, and practices.” This process occurred over more than two years. It is therefore reasonable to assume that GOs, having never had to comply with a vegetation management standard, be afforded adequate time to do so.

Beyond the corrected typo, no changes were made.

Organization	Yes or No	Question 4 Comment
Ameren Services	Negative	The 2 year compliance time line is far too long. There is significant industry evidence that was developed in the drafting of Version 2 that supports a one year compliance time-line for new lines. This is evidenced in Version 2. Thus there is no basis for the 2 years.
<p><b>Response:</b> Thank you for your comment. The SDT choose the time in the implementation plan based upon comments of stakeholders and the fact that the implementation plan for <u>Version 0 standards</u> stated “the Version 0 Reliability Standards are generally a translation and clarification of existing operating policies and planning standards, entities that are in compliance with NERC policies</p>		

Organization	Yes or No	Question 4 Comment
<p>and standards today are expected to be able to remain in compliance with the Version 0 Reliability Standards with their existing procedures, tools, and practices.” This process occurred over more than two years. It is therefore reasonable to assume that GOs, having never had to comply with a vegetation management standard, be afforded adequate time to do so.</p>		
Texas Reliability Entity	No	<p>A compliance timeframe for the applicable GOs of two years is too long and the scenario used as a basis provides no timing specifics or details. Moreover, the 12 months for an existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard is arguably the same situation as an applicable GO but the applicable GO has an additional 12 months to come into compliance.</p>
<p><b>Response:</b> Thank you for your comment. The SDT choose the time in the implementation plan based upon comments of stakeholders and the fact that the implementation plan for <a href="#">Version 0 standards</a> stated “the Version 0 Reliability Standards are generally a translation and clarification of existing operating policies and planning standards, entities that are in compliance with NERC policies and standards today are expected to be able to remain in compliance with the Version 0 Reliability Standards with their existing procedures, tools, and practices.” This process occurred over more than two years. It is therefore reasonable to assume that GOs, having never had to comply with a vegetation management standard, be afforded adequate time to do so. The SDT does not believe that a TO’s acquisition of a new asset is the same as applying new requirements to a GO.</p>		
Ingleside Cogeneration LP (Occidental Chemical)	No	<p>Based upon similar issues addressed in Compliance Application Notices (CANs), the drafting team needs to specify when the first vegetation management inspection quarterly report, and any other requirement with an assigned interval in FAC-003-3 or FAC-003-X. Even if the decision is to adopt the same criteria proposed in CAN-0012, the industry is better served with a clear distinction made up front.</p>
<p><b>Response:</b> Thank you for your comment. This is a comment that is outside the scope of the SDT, and in fact deals with a larger body of standards than just FAC-003. No change made.</p>		
PSEG	No	It’s no longer applicable.
<p><b>Response:</b> Thank you for your comment. The SDT acknowledges that in November 2011, NERC’s Board of Trustees adopted FAC-003-2</p>		

Organization	Yes or No	Question 4 Comment
<p>– Transmission Vegetation Management (developed under Project 2007-07 Vegetation Management). Based on this approval, NERC staff will file FAC-003-2 with the applicable regulatory authorities. The Project 2010-07 SDT will move forward with ballots for both FAC-003-3 (proposed changes to the BOT-adopted FAC-003-2) and FAC-003-X (proposed changes to the FERC-approved FAC-003-1) with the intention of eventually only filing FAC-003-3. The SDT has elected to carry FAC-003-X through to ballot because if FAC-003-2 and FAC-003-3 are not approved by FERC, the SDT wants to be ready to file FAC-003-X to ensure that there is a functional entity responsible for managing vegetation on the piece of line commonly known as the generator interconnection Facility.</p> <p>Note that for its recirculation ballot, the SDT will be balloting <b>both</b> FAC-003-3 and FAC-003-X, but stakeholders should <b>not</b> vote as though they are choosing one or the other. As stated above, the SDT plans to present FAC-003-3 alone to NERC’s Board of Trustees, but it wants to have FAC-003-X ready to submit to the Board if, for some reason, neither FAC-003-2 nor FAC-003-3 are approved by FERC. Members of the ballot body should vote on the merits of each version of FAC-003 individually. <b>In other words, stakeholders who support adding GOs to the applicability of FAC-003 should vote in the affirmative for both FAC-003-3 and FAC-003-X.</b></p>		
Manitoba Hydro	No	See question 3 comments.
<p><b>Response:</b> See the SDT’s response to Question 3.</p>		
Southwest Power Pool Standards Development Team	No	The effective dates should be consistent with the original standard. If there is a reason for the extension we would like to know why.
<p><b>Response:</b> Thank you for your comment. The SDT choose the time in the implementation plan based upon comments of stakeholders and the fact that the implementation plan for <a href="#">Version 0 standards</a> stated “the Version 0 Reliability Standards are generally a translation and clarification of existing operating policies and planning standards, entities that are in compliance with NERC policies and standards today are expected to be able to remain in compliance with the Version 0 Reliability Standards with their existing procedures, tools, and practices.” This process occurred over more than two years. It is therefore reasonable to assume that GOs, having never had to comply with a vegetation management standard, be afforded adequate time to do so.</p>		
Southern Company	Yes	The development of a working TVMP will take some time to initialize. The 1 year time frame for R3 is appropriate. The 2 year time frame for all other requirements is appropriate.

Organization	Yes or No	Question 4 Comment
<b>Response:</b> Thank you for your comment and support.		
Seattle City Light	Yes	The explanation deals with the fact that there are simultaneous revisions of FAC-003 underway by two different teams.
<b>Response:</b> Thank you for your comment and support.		
MRO NSRF	Yes	There may be a typographical error on the effective date. As currently drafted the standard states: In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption. Should it be worded as follows? In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 R1 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.
<b>Response:</b> Thank you for your comment. The SDT agrees with you. "Requirement R3," will be corrected to "Requirement R1."		
RES Americas Development/ American Wind Energy Association	Yes	Yes, as with our comments to question 2, since there is no exigent reason why this standard needs to be put in place at once, we support the proposed compliance timeframe. We believe that it will allow generators a reasonable time to comply with the requirement.



Organization	Yes or No	Question 4 Comment
<b>Response:</b> Thank you for your comment and support.		
SERC OC Standards Review Group	Yes	
Northeast Power Coordinating Council, Northeast Power Coordinating Council	Yes	
Southwest Power Pool Regional Entity	Yes	
SERC Planning Standards Subcommittee	Yes	
Florida Municipal Power Agency	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Electric Power Supply Association	Yes	
American Electric Power	Yes	
BP Wind Energy North	Yes	

Organization	Yes or No	Question 4 Comment
America Inc.		
Exelon	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
American Transmission Company	Yes	
South Carolina Electric and Gas	Yes	
Sempra Generation	Yes	
Entergy Services	Yes	
Xcel Energy	Yes	
Cowlitz County PUD	Yes	
Constellation Power Source Generation	Yes	
Western Electricity Coordinating Council		

Organization	Yes or No	Question 4 Comment
Puget Sound Energy, Inc.		
Compliance & Responsibility Organization		
Bonneville Power Administration		
Consolidated Edison Co. of NY, Inc.		
ReliabilityFirst		
Tennessee Valley Authority		

5. In the FAC-003-3 implementation plan, the SDT has attempted to account for a number of different scenarios that could play out with respect to the filing and approvals of FAC-003-2 and FAC-003-3. Do you support this approach? If there are other scenarios that the SDT needs to account for, please suggest them here.

#### Summary Consideration:

The SDT thanks all stakeholders for their comments. The vast majority of stakeholders support the compliance timeframes as proposed and explained in the Implementation Plan for FAC-003-3.

One commenter thought that two years was too long for an Implementation Plan for this standard. The SDT reminded those commenters that the time frame was based on previous stakeholder comments and the fact that the Implementation Plan for Version 0 standards stated “the Version 0 Reliability Standards are generally a translation and clarification of existing operating policies and planning standards, entities that are in compliance with NERC policies and standards today are expected to be able to remain in compliance with the Version 0 Reliability Standards with their existing procedures, tools, and practices.” This process occurred over more than two years. It is therefore reasonable to assume that GOs, having never had to comply with a vegetation management standard, be afforded adequate time to do so.

Some stakeholders expressed confusion about the relationship between FAC-003-3 and the recently BOT-approved FAC-003-2. The SDT acknowledges that in November 2011, NERC’s Board of Trustees adopted FAC-003-2 – Transmission Vegetation Management (developed under Project 2007-07 Vegetation Management). Based on this approval, NERC staff will file FAC-003-2 with the applicable regulatory authorities. The Project 2010-07 SDT will move forward with ballots for both FAC-003-3 (proposed changes to the BOT-adopted FAC-003-2) and FAC-003-X (proposed changes to the FERC-approved FAC-003-1) with the intention of eventually only filing FAC-003-3. The SDT has elected to carry FAC-003-X through to ballot because if FAC-003-2 and FAC-003-3 are not approved by FERC, the SDT wants to be ready to file FAC-003-X to ensure that there is a functional entity responsible for managing vegetation on the piece of line commonly known as the generator interconnection Facility.

All stakeholders should note that for its recirculation ballot, the SDT will be balloting **both** FAC-003-3 and FAC-003-X, but stakeholders should **not** vote as though they are choosing one or the other. As stated above, the SDT plans to present FAC-003-3 alone to NERC’s Board of Trustees, but it wants to have FAC-003-X ready to submit to the Board if, for some reason, neither FAC-003-2 nor FAC-003-3 are approved by FERC. Members of the ballot body should vote on the merits of each version of FAC-003 individually. **In other words, stakeholders who support adding GOs to the applicability of FAC-003 should vote in the affirmative for both FAC-003-3 and FAC-003-X.**

Organization	Yes or No	Question 5 Comment
Manitoba Hydro	No	See question 3 comments.
<b>Response:</b> See the SDT’s response to Question 3.		
Southern Company	No	We believe that a standard development process should not have parallel paths where the same version is being modified by multiple teams. The uncertainty in which development path leads to confusion in the industry and ultimately proves to have wasted some resources for the path that does not come to fruition.
<p><b>Response:</b> Thank you for your comment. While the SDT agrees this is not preferable, it was necessary given the urgency of both projects. The SDT did the best it could to describe the scenarios and reasons for posting multiple versions.</p> <p>In November 2011, NERC’s Board of Trustees adopted FAC-003-2 – Transmission Vegetation Management (developed under Project 2007-07 Vegetation Management). Based on this approval, NERC staff will file FAC-003-2 with the applicable regulatory authorities. The Project 2010-07 SDT will move forward with ballots for both FAC-003-3 (proposed changes to the BOT-adopted FAC-003-2) and FAC-003-X (proposed changes to the FERC-approved FAC-003-1) with the intention of eventually only filing FAC-003-3. The SDT has elected to carry FAC-003-X through to ballot because if FAC-003-2 and FAC-003-3 are not approved by FERC, the SDT wants to be ready to file FAC-003-X to ensure that there is a functional entity responsible for managing vegetation on the piece of line commonly known as the generator interconnection Facility.</p>		
Ingleside Cogeneration LP (Occidental Chemical)	Yes	Ingleside Cogeneration agrees that the SDT’s approach is thorough. We are far more concerned about FAC-003’s applicability criteria and implementation time frame at this point - as stated in our responses to questions 3 and 4.
<b>Response:</b> Thank you for your comment and support. Please refer to the SDT’s responses to Questions 3 and 4.		
ACES Power Marketing Standards Collaborators	Yes	With recent NERC BOT approval of the FAC-003-2 standard, the drafting team should continue to monitor the standard progress with FERC and make necessary adjustments to the implementation plan.
<b>Response:</b> Thank you for your comment. The SDT acknowledges that FAC-003-2 was recently approved by the BOT. The SDT does not		

Organization	Yes or No	Question 5 Comment
<p>see the need to revise the GO implementation plan, as it already accounts for a number of scenarios that could occur based on how FERC handles the filing of FAC-003-2.</p>		
<p>Ameren</p>		<p>(a) There is no technical basis for the one mile length exemption. In fact, one could argue that a very short line, 300 feet in length, that experienced a fault from a tree at "the end of the circuit", i.e near the switchyard fence, would have much more of an impact on the BES because the fault would be limited by much less impedance.</p> <p>(b) It is also unclear in this version if a GO that owned one line that was 1.2 miles in length would have to comply for the entire length of said line, or just 0.2 miles of said line. If the GO is responsible for 1.2 miles, then that argues that the first mile is important and consequently there is no basis for ignoring the first mile on other lines. If the GO is only responsible for 0.2 miles, what is the technical basis to ignore a mile? And would it be the first mile from the switchyard that is ignored, or is the middle mile, or the last mile where it connects to the TO? Or could the GO decide? Or could the GO pick sections of the line that amount to a mile that they can ignore? This seems like something that should be addressed for compliance.</p> <p>(c) The 2 year compliance time line is far too long. There is significant industry evidence that was developed in the drafting of Version 2 that supports a one year compliance time-line for new lines. This is evidenced in Version 2. Thus there is no basis for the 2 years</p>
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled "<a href="#">Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface</a>," the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: <del>“Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”</del></p> <p>With respect to your second comment, the SDT intended for the length qualifier to be just that; if the overhead portion of a Facility</p>		

Organization	Yes or No	Question 5 Comment
<p>exceeds the distance, <a href="#">the entire Facility</a> is subject to the requirements of the standard.</p> <p>The SDT choose the time in the implementation plan based upon reasons it documented in the <a href="#">accompanying implementation plan</a> and also based upon comments of stakeholders.</p>		
PSEG	Yes	
SERC OC Standards Review Group	Yes	
Southwest Power Pool Standards Development Team	Yes	
Northeast Power Coordinating Council, Northeast Power Coordinating Council	Yes	
MRO NSRF	Yes	
SERC Planning Standards Subcommittee	Yes	
Florida Municipal Power Agency	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
Electric Power Supply Association	Yes	

Organization	Yes or No	Question 5 Comment
American Wind Energy Association	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Exelon	Yes	
Seattle City Light	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
American Transmission Company	Yes	
South Carolina Electric and Gas	Yes	
RES Americas Development	Yes	
Sempra Generation	Yes	
Entergy Services	Yes	



Organization	Yes or No	Question 5 Comment
Xcel Energy	Yes	
Cowlitz County PUD	Yes	
Texas Reliability Entity	Yes	
Constellation Power Source Generation	Yes	
Tennessee Valley Authority	Yes	
Southwest Power Pool Regional Entity		
Western Electricity Coordinating Council		
Puget Sound Energy, Inc.		
Compliance & Responsibility Organization		
Bonneville Power Administration		
Consolidated Edison Co. of NY, Inc.		
ReliabilityFirst		

6. In its technical justification document, the SDT reviews all standards that had been proposed for substantive modification in the Ad Hoc Group’s original support and explains why, with the exception of FAC-003, modifying them would not provide any reliability benefit. Do you support these justifications? If you believe the SDT needs to add more information to its rationale for any of these decisions, please include suggested language here.

**Summary Consideration:**

The SDT thanks all stakeholders for their comments.

A few commenters pointed out that the wording in R1 and R2 of PRC-005-1a requires the same explicit reference to a generator interconnection Facility that was added in PRC-004-2a R2. The SDT is developing revisions to PRC-005-1a and will post them soon.

Many commenters encouraged the SDT to reexamine the standards and requirements that FERC and NERC applied to GOs and GOPs in their Milford/Cedar Creek order and draft compliance directive regarding generator leads. The SDT pointed out that the NERC Standard Processes Manual does not address the issue of how to deal with FERC Orders (that don’t include explicit directives), or NERC directives, within the standards process, and until this round of comments, when NERC staff submitted comments, the SDT had no formal mandate that would have made it appropriate to consider the content of the proposed directive.

Based on stakeholder comments, the SDT expanded its technical justification document (posted under “Supporting Materials”) to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.

One commenter remains concerned about the scope of the SDT. The SDT reminded this commenter that its scope is addressed in the SAR and that its intent is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT also refers the commenter to the document titled Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document. Specifically, see the last paragraph on page 4 and first two on page 5.

Organization	Yes or No	Question 6 Comment
Manitoba Hydro	Negative	The intention of the NERC SDT in revising these standards is not clear. While the Technical Justification document states that the SDT intended to focus on a Generator

Organization	Yes or No	Question 6 Comment
		<p>Owner’s radial interconnection facilities, the scope of the revised standard (s) is not confined to such facilities. The very broadly defined term “Facility” is used. Moreover, the Technical Justification document’s reference to the FERC decision in Cedar Creek as a basis for the revision of additional standards is confusing, since that decision did not specifically address the issue of radial facilities and supported NERC’s registration of GOs as TOs.</p>
<p><b>Response:</b> Thank you for your comment. The scope of this SDT is addressed in the <a href="#">SAR</a>. The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT determined that it should first address “low-hanging fruit” and believes these to be sole-use Facilities (see posted examples under “Supporting Materials”) – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP). Through our deliberations, we came to the conclusion that an interconnection Facility owned or operated by a GO or GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT.</p> <p>The SDT also refers the commenter to the document titled <a href="#">Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document</a>. Specifically, see the last paragraph on page 4 and first two on page 5.</p>		
Texas Reliability Entity	No	<p>Our negative votes on FAC-003 reflect our concern that this project has not considered all of the applicable standards. Why did the SDT choose to only review the Ad Hoc Group’s standards when there have been multiple registration appeals in which FERC and NERC have repeatedly cited specific additional TO/TOP standards that were determined to be applicable to GO/GOPs? This SDT project would serve a tremendous value to the ERO and in particular industry if it were to address the technical aspects of the following FERC ordered applicable standards: PRC-001-1 R2, R4; PRC-004-1 R1; TOP-004-2 R6; PER-003-1 R1; FAC-003-1 R1, R2; TOP-001-1a R1 and FAC-004-2 R2. The SDT team should analyze the FERC orders, the applicable standards indicated, and the circumstances and facts involved, and technically justify why no reliability gap exists if these standards are not applied to GO interface facilities. The SDT should include more “technical” information in its technical justification document. For example, in regards to TOP-004-2 R7, the SDT technical</p>

Organization	Yes or No	Question 6 Comment
		<p>justification states that there is no reliability gap because, “. . . because an operator has a fiduciary obligation to protect a Facility for which it is operationally responsible.” An entity having a fiduciary obligation is not a technical justification of why a reliability gap does not exist. Moreover, by that logic there would be no need for many standards because every registered entity has a fiduciary obligation to protect its facilities.</p>
<p><b>Response:</b> Thank you for your comment. The NERC <a href="#">Standard Processes Manual</a> does not address the issue of how to deal with FERC Orders (that don’t include explicit directives), or NERC directives, within the standards process, and until this round of comments, when NERC staff submitted comments, the SDT had no formal mandate that would have made it appropriate to consider the content of the directive you reference.</p> <p>We would like to clarify, in response to the comment concerning TOP-004-2 R7, that in the document titled “<a href="#">Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface</a>” the SDT also stated “FAC-008-1—Facility Ratings Methodology and FAC-009-1—Establish and Communicate Facility Ratings already infer that the reason for establishing a ratings methodology and communicating facility ratings to the Reliability Coordinator, Planning Authority, Transmission Planner, and Transmission Operator is for use in reliable planning and operation of the Bulk Electric System.”</p> <p>Based on your and other comments, we have expanded our technical justification document (posted under “Supporting Materials”) to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.</p>		
PSEG	No	<p>PRC-005-1 - Transmission and Generation Protection System Maintenance and Testing was recommended by the Ad Hoc Group for modification, but not addressed to the technical justification document. It should be.</p>
<p><b>Response:</b> Thank you for your comment. We have reviewed PRC-005-1a and believe that the wording in R1 and R2 of that standard require the same explicit reference to a generator interconnection Facility that was added in PRC-004-2a R2. The SDT is developing revisions to PRC-005-1a and will post them soon.</p>		
Florida Municipal Power	No	see comment to Question 7

Organization	Yes or No	Question 6 Comment
Agency		
<b>Response:</b> See the SDT’s response to Question 7.		
Manitoba Hydro	No	See Question 7 comments.
<b>Response:</b> See the SDT’s response to Question 7.		
MRO NSRF	No	The NSRF has one concern with the current justification and definitions. At some point, if enough interconnections are made to generator outlet leads in accordance with FAC-001, the original generator operator will be a Transmission Operator and a Transmission Owner. This point in time needs to be explicitly defined by the drafting team.
<b>Response:</b> The SDT cannot act on this comment. Registration is outside the scope of this SDT and resides with NERC and the Regional Entity.		
Manitoba Hydro		If the drafting team intends to limit the scope of FAC-001-1 to GO owned radial generator interconnection facilities that are not deemed BES transmission and therefore would not require the registration of the GO as a TO, Manitoba Hydro disagrees with the proposed changes to FAC-001-1 as Generator Owners may not have the models or expertise to perform interconnection studies to determine if there is an impact on the Transmission Network. This concern is echoed in the technical justification document provided by NERC: ‘the SDT acknowledges that the Generator Owner may not, at the time it agrees or is compelled to allow a third part to interconnect, have the necessary expertise to conduct the required interconnect studies to meet this standard... the Generator Owner will have to acquire such expertise. How the Generator Owner chooses to do so is not for the SDT to determine.’ Although it may not be for the SDT to determine how a GO obtains technical expertise, ensuring that such expertise is acquired before a GO conducts the required interconnection studies should be a concern to NERC as this directly affects

Organization	Yes or No	Question 6 Comment
		<p>the reliability of the BES. As a result, all interconnection requests should be implemented by the TO providing the GO with connection to the BES regardless if the interconnection point is within a Generation Owner facility or End-User facility as the TO is in the best position to set unbiased connection requirements to ensure the reliability of the BES is maintained. If the scope of FAC-001-1 also applies to GO owned BES transmission facilities, Manitoba Hydro strongly believes that the Compliance Registry should apply and the GOs should be required to register as a TO and abide by all applicable standards to that functional type. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. Reliability gaps would be better addressed if select GOs and GOPs registered as TOs and TOPs to ensure all reliability standards, including the protection standards, are met so the reliability of the BES is maintained. At this time, this would not lead to a large number of extra registrations since, as stated in the technical justification document, ‘interconnection requests for Generator Owner Facilities are still relatively rare.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees this is a complex issue and did its best to outline how it arrived at its position in the document titled <a href="#">“Technical Justification: FAC-001-1.”</a></p> <p>The SDT points out that if the GO is part of an RTO, then the GO will be coordinating any interconnection studies either directly or indirectly with the RTO interconnection process. If the GO is not part of an RTO, then the GO will be required to follow the pro forma interconnection procedures from Order 2003. The Order 2003 procedures require the GO to coordinate any studies with an affected system which could include Facilities owned by one, or more, TO on the other side of the GO’s existing point of interconnection.</p> <p>The SDT has proposed the modification of a select set of standards so that they apply to GOs and GOPs as an alternative to registering all GOs and GOPs as TOs and TOPs. The SDT does agree that upon interconnection of a third party, other standards or registrations may apply as appropriate.</p>		
Electric Power Supply Association	Affirmative	<p>All TO requirements for FAC-001-1 would apply if and when GO executes an Agreement to evaluate the reliability impact of interconnecting a third party Facility to its existing generation interconnection Facility. The execution of the agreement is necessary to comply with FAC-002-1 and start the compliance clock with the</p>

Organization	Yes or No	Question 6 Comment
		<p>applicable regulatory authority. Thus as the Project 2010-07 Standard Drafting Team (SDT) in its technical justification has stated, “If, and only if, the existing owner of a generator interconnection Facility has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to its existing generation Facility” then FAC-001-1 should apply. EPSA concurs with SDT’s conclusion. The SDT has examined the issue regarding if future requests for transmission service on the interconnection Facility and in doing so acknowledged that when that Facility adopted open access and was providing transmission service it would necessitate re-evaluation of the need for the Facility to be maintained in accordance with FAC-001-1, Requirements 2 and 4. This service would indeed prompt the necessary agreement the SDT contemplates in its technical justification of FAC-001-1. EPSA believes this serves as the necessary trigger for evaluation of Requirements 2 and 4 under FAC-001-1 for GOs.</p>
<p><b>Response:</b> Thank you for your comment and support.</p>		
<p>Infigen Energy US</p>	<p>Affirmative</p>	<p>Infigen supports the FAC-001-1 technical analysis by the Project 2010-07 SDT, which states in part that “If, and only if, the existing owner of a generator interconnection Facility has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to its existing generation Facility would the proposed FAC-001-1 apply”. We agree with the SDT’s reasoning that if the owner of the existing generator interconnection Facility agrees, or is compelled to allow a third party to interconnect, but can do so using existing agreements, contracts, and/or tariffs [to avoid requiring additional executed Agreement(s)], this is the most prudent and effective way to manage this process with continuity. In order to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility more expediently, it can avoid having to develop its own connection requirements or perform additional impact studies, to the extent possible. We find it reasonable to negotiate with the existing Transmission Owner, Transmission Planner, and/or Transmission Service Provider to manage this requirement, utilizing their</p>

Organization	Yes or No	Question 6 Comment
		existing processes and Agreements for the purpose of fulfilling FAC-001-1.
<p><b>Response:</b> Thank you for your comment and support.</p>		
Southern Company	Yes	Additional responses are needed to justify the exclusion of the list of requirements and standards found in the recent FERC order denying the rehearing request of the Compliance Registry Appeals of Cedar Creek and Milford. (135 FERC Para. 61,241). Please see our response to Question 10 for a detailed discussion on this topic.â€,â€,â€,
<p><b>Response:</b> Thank you for your comment. The NERC <a href="#">Standard Processes Manual</a> does not address the issue of how to deal with FERC Orders (that don't include explicit directives), or NERC directives, within the standards process, and until this round of comments, when NERC staff submitted comments, the SDT had no formal mandate that would have made it appropriate to consider the content of the directive you reference.</p> <p>Based on your and other comments, we have expanded our technical justification document (posted under "Supporting Materials") to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.</p>		
Constellation Power Source Generation	Yes	Constellation supports the SDT justifications and offers additional information in our response to question 10.
<p><b>Response:</b> Thank you for your comment and support.</p>		
Ingleside Cogeneration LP (Occidental Chemical)	Yes	Ingleside Cogeneration LP believes the SDT has spent a significant amount of time and effort to demonstrate that only FAC-001, FAC-003, and PRC-004 need to be modified to address any reliability gaps that may exist related to the GO-TO interconnection. We agree that the other standards/requirements identified by the Ad Hoc Group are covered elsewhere.
<p><b>Response:</b> Thank you for your comment and support.</p>		



Organization	Yes or No	Question 6 Comment
American Wind Energy Association	Yes	The reasoning of the SDT is comprehensive and makes a strong case for why there is no need for additional standards to be applied to GO/GOP lead lines as they will not improve the reliability of the Bulk Electric System. In fact, as noted above, such additional standards may decrease reliability by diverting the GO/GOP's resources from the operation of the equipment that actually produces electricity - the generation equipment itself.
<b>Response:</b> Thank you for your comment and support.		
RES Americas Development	Yes	The reasoning of the SDT is comprehensive and makes a strong case for why there is no need for additional standards to be applied to GO/GOP lead lines as they will not improve the reliability of the Bulk Electric System. In fact, as noted above, such additional standards may decrease reliability by diverting the GO/GOP's resources from the operation of the equipment that actually produces electricity - the generation equipment itself.
<b>Response:</b> Thank you for your comment and support.		
SERC OC Standards Review Group	Yes	
Southwest Power Pool Standards Development Team	Yes	
Northeast Power Coordinating Council, Northeast Power Coordinating Council	Yes	
Southwest Power Pool Regional Entity	Yes	

Organization	Yes or No	Question 6 Comment
SERC Planning Standards Subcommittee	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Electric Power Supply Association	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Exelon	Yes	
Seattle City Light	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
American Transmission Company	Yes	
South Carolina Electric and	Yes	

Organization	Yes or No	Question 6 Comment
Gas		
Sempra Generation	Yes	
Xcel Energy	Yes	
Cowlitz County PUD	Yes	
Western Electricity Coordinating Council		
Puget Sound Energy, Inc.		
Compliance & Responsibility Organization		
Bonneville Power Administration		
Independent Electricity System Operator		
Ameren		
Consolidated Edison Co. of NY, Inc.		
Entergy Services		
ReliabilityFirst		

Organization	Yes or No	Question 6 Comment
Tennessee Valley Authority		

**7. The SDT is attempting to modify a set of standards so that radial generator interconnection Facilities are appropriately accounted for in NERC's Reliability Standards, both to close reliability gaps and to prevent the unnecessary registration of GOs and GOPs at TOs and TOPs. Does the set of standards currently posted achieve this goal?**

**Summary Consideration:**

The SDT thanks all stakeholders for their comments. Most commenters support the SDT's work and agree that the set of standards for which the SDT has proposed modification ensure that radial generator interconnection Facilities are appropriately accounted for in NERC's Reliability Standards.

One commenter continues to express confusion about the scope of the SDT's work in general. The SDT reminded this commenter that its scope is addressed in the [SAR](#). The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT determined that it should first address "low-hanging fruit" and believes these to be sole-use Facilities (see posted examples under "Supporting Materials") – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP). Through its deliberations, the SDT came to the conclusion that an interconnection Facility owned or operated by a GO or GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT. The SDT also refers the commenter to the document titled [Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document](#) (specifically, the last paragraph on page 4 and first two on page 5). The SDT has proposed the modification of a select set of standards so that they apply to GOs and GOPs as an alternative to registering all GOs and GOPs as TOs and TOPs, a strategy that has been widely supported by the stakeholder body. The SDT does agree that upon interconnection of a third party, other standards or registrations may apply as appropriate.

One commenter asked the SDT to specify what it means by "radial." By "radial generator interconnection Facilities," the SDT means sole-use Facilities (see posted examples under "Supporting Materials") – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP).

A few commenters suggested that the SDT address those standards cited by FERC and NERC in related projects. The SDT pointed out that the NERC [Standard Processes Manual](#) does not address the issue of how to deal with FERC Orders (that don't include explicit directives), or NERC directives, within the standards process. However, based on stakeholder comments, the SDT has expanded its technical justification document (posted under "Supporting Materials") to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.

One commenter suggested that the SDT include the GO in TOP-004-2 R6, but the SDT continues to maintain that no gap exists because TOP-002-2 R3 already requires the GO to coordinate with its host BA and TSP, who in turn are required to coordinate with their TOPs.

One commenter pointed out that the Data Retention section of the proposed PRC-004-2.1a also requires modification to include the generator interconnection Facility. The SDT agrees and made this change.

Organization	Yes or No	Question 7 Comment
Manitoba Hydro	Negative	<p>Manitoba Hydro has the following comments:</p> <p>1) The intention of the NERC SDT in revising these standards is not clear. While the Technical Justification document states that the SDT intended to focus on a Generator Owner’s radial interconnection facilities, the scope of the revised standard (s) is not confined to such facilities. The very broadly defined term “Facility” is used. Moreover, the Technical Justification document’s reference to the FERC decision in Cedar Creek as a basis for the revision of additional standards is confusing, since that decision did not specifically address the issue of radial facilities and supported NERC’s registration of GOs as TOs.</p> <p>2) Manitoba Hydro strongly disagrees with bypassing the NERC Compliance Registry and only having a limited set of standards apply to the GOs ‘interconnection facilities’ If a Generator Owner wants to own transmission facilities and it falls under the definition of a Transmission Owner under the NERC Registry Criteria, then all the Requirements applicable to a TO should apply. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. Reliability gaps would be better closed if select GOs and GOPs simply registered as TOs and TOPs. At this time, this would not lead to a large number of extra registrations since, as stated in the technical justification document, ‘interconnection requests for Generator Owner Facilities are still relatively rare.</p>
<p><b>Response:</b> Thank you for your comment. The scope of this SDT is addressed in the <a href="#">SAR</a>. The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT determined that it should first address “low-hanging fruit” and believes these to be sole-use Facilities (see posted examples under</p>		

Organization	Yes or No	Question 7 Comment
<p>“Supporting Materials”) – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP). Through our deliberations, we came to the conclusion that an interconnection Facility owned or operated by a GO or GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT.</p> <p>The SDT also refers the commenter to the document titled <a href="#">Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document</a>. Specifically, see the last paragraph on page 4 and first two on page 5.</p> <p>The SDT has proposed the modification of a select set of standards so that they apply to GOs and GOPs as an alternative to registering all GOs and GOPs as TOs and TOPs, a strategy that has been widely supported by the stakeholder body. The SDT does agree that upon interconnection of a third party, other standards or registrations may apply as appropriate.</p>		
Manitoba Hydro	Negative	<p>Manitoba Hydro strongly disagrees with bypassing the NERC Compliance Registry and only having a limited set of standards apply to the GOs ‘interconnection facilities’ If a Generator Owner wants to own transmission facilities and it falls under the definition of a Transmission Owner under the NERC Registry Criteria, then all the Requirements applicable to a TO should apply. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. Reliability gaps would be better closed if select GOs and GOPs simply registered as TOs and TOPs. At this time, this would not lead to a large number of extra registrations since, as stated in the technical justification document, ‘interconnection requests for Generator Owner Facilities are still relatively rare.</p>
<p><b>Response:</b> Thank you for your comment. The SDT has proposed the modification of a select set of standards so that they apply to GOs and GOPs as an alternative to registering all GOs and GOPs as TOs and TOPs, a strategy that has been widely supported by the stakeholder body. The SDT does agree that upon interconnection of a third party, other standards or registrations may apply as appropriate.</p>		
PSEG	No	<p>It would be helpful if the SDT defined what it means by the term “radial generator interconnection Facilities.” Does it mean interconnection Facilities that under Normal Clearing for a fault do not interrupt flows on other BES Elements? This is also confusing because of the radial exclusion included in the BES definition work in</p>

Organization	Yes or No	Question 7 Comment
		Project 2010-17. That definition would allow part of a three-terminal circuit to be excluded from the BES, while the other parts are included in the BES.
<p><b>Response:</b> Thank you for your comment. By “radial generator interconnection Facilities,” the SDT means sole-use Facilities (see posted examples under “Supporting Materials”) – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP). Through our deliberations, we came to the conclusion that an interconnection Facility owned or operated by a GO/GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT.</p>		
Texas Reliability Entity	No	See comment 6.
<p><b>Response:</b> See the SDT’s response to Question 6.</p>		
Manitoba Hydro	No	<p>The SDT’s proposed modifications gives special treatment to the Generator Owner in that it allows the Generator Owner TO status for a couple of standards (FAC-001, FAC-003 and PRC-004), but exempts the Generator Owner from many of the standards applicable to a TO. The NERC Registry Criteria defines the various functional entities. If a Generator Owner wants to own transmission facilities and it falls under the definition of a Transmission Owner under the NERC Registry Criteria, then all the Requirements applicable to a TO should apply. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. Reliability gaps would be better closed if select GOs and GOPs simply registered as TOs and TOPs. At this time, this would not lead to a large number of extra registrations since, as stated in the technical justification document, ‘interconnection requests for Generator Owner Facilities are still relatively rare.</p>
<p><b>Response:</b> Thank you for your comment. The scope of this SDT is addressed in the <a href="#">SAR</a>. The intent of the SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT determined that it should first address “low-hanging fruit” and believes these to be sole-use Facilities (see posted examples under “Supporting Materials”) – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP). Through our deliberations, we came to the conclusion that an interconnection Facility owned or operated by a GO or</p>		



Organization	Yes or No	Question 7 Comment
<p>GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT.</p> <p>The SDT also refers the commenter to the document titled <a href="#">Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document</a>. Specifically, see the last paragraph on page 4 and first two on page 5.</p> <p>The SDT has proposed the modification of a select set of standards so that they apply to GOs and GOPs as an alternative to registering all GOs and GOPs as TOs and TOPs, a strategy that has been widely supported by the stakeholder body. The SDT does agree that upon interconnection of a third party, other standards or registrations may apply as appropriate.</p>		
<p>Southwest Power Pool Regional Entity</p>	<p>No</p>	<p>The Technical Justification document did not review the standards FERC identified in paragraphs 71 and 87 of 135 FERC ¶ 61,241 ORDER DENYING APPEALS OF ELECTRIC RELIABILITY ORGANIZATION REGISTRATION DETERMINATIONS. The SDT needs to review these standards to determine if changes are needed; otherwise, FERC will require registration of GOs and GOPs as TOs and TOPs to address reliability gaps. If the SDT determines no changes are needed to these FERC-identified standards, they should provide justification.</p>
<p><b>Response:</b> Thank you for your comment. The NERC <a href="#">Standard Processes Manual</a> does not address the issue of how to deal with FERC Orders (that don't include explicit directives) within the standards process. However, based on your and other comments, we have expanded our technical justification document (posted under "Supporting Materials") to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.</p>		
<p>Southern Company</p>	<p>No</p>	<p>We don't believe the effort realizes the goal because 1) it is inclusive of FAC-001 that does not need any modifications and 2) the effort needs to reinforce the appropriate justification not to include the additional standards FERC has identified in their Cedar Creek and Milford Orders.</p>
<p><b>Response:</b> The SDT thanks you for your comment. The SDT believes that comment (1) is a complex issue and did its best to outline how it arrived at its position in the document titled "<a href="#">Technical Justification: FAC-001-1.</a>"</p>		

Organization	Yes or No	Question 7 Comment
		<p>As for comment (2), the NERC <a href="#">Standard Processes Manual</a> does not address the issue of how to deal with FERC Orders (that don't include explicit directives) within the standards process. However, based on your and other comments, we have expanded our technical justification document (posted under "Supporting Materials") to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.</p>
Western Electricity Coordinating Council	No	<p>WECC casts an affirmative vote for the SDT proposal as a necessary but not sufficient step in addressing the GOTO matter. WECC, NERC, and the other Regions developed a subset of Standards and Requirements that were considered necessary to address potential gaps for transmission interconnection facilities and operations to be included in a proposed NERC Directive, which is expected to issue by year-end. The subset of requirements developed for the proposed NERC Directive were informed by the applicable FERC Orders. Consequently, it is important that the SDT address the comparative reliability risks between the proposed NERC Directive List and the SDT Proposal to assure that reliability gaps will not result from the SDT proposal. Please see NERC's proposed Directive for the rationale and technical justification.</p>
<p><b>Response:</b> Thank you for your comment. The NERC <a href="#">Standard Processes Manual</a> does not address the issue of how to deal with FERC Orders (that don't include explicit directives), or NERC directives, within the standards process, and until this round of comments, when NERC staff submitted comments, the SDT had no formal mandate that would have made it appropriate to consider the content of the directive you reference.</p> <p>However, based on your and other comments, we have expanded our technical justification document (posted under "Supporting Materials") to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.</p>		
Florida Municipal Power Agency		<p>FMPA believes that TOP-004-2 R6.2 ought to also be addressed in the standards as applicable to GOPs. The requirements reads: R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and</p>

Organization	Yes or No	Question 7 Comment
		<p>implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: R6.2. Switching transmission elements. Although planned outages are covered in other standards applicable to a GOP, switching to close / synchronize a generator back to the system is not specifically covered in the standards. Some have argued that TOP-002-2 R3 causes GOPs to coordinate its current day plans with the TOP; however, the name of the standard is “Transmission Operations Planning” and therefore implies the availability of the generator and related equipment and not necessary implies the policies and procedures for switching operations; which includes synchronization. FMPA cannot imagine a generator that would not have such switching / synchronization policies and procedures coordinated with its interconnecting TOP; as such would normally be required through a Large Generator Interconnection Agreement through a pro forma OATT; however, FMPA is not aware of any instance in the standards that covers this. As such, FMPA recommends including TOP-004-2 R6.2 as being applicable to a GOP.</p>
<p><b>Response:</b> Thank you for your comment. We don’t agree that the gap exists because TOP-002-2 R3 already requires the GO to coordinate with its host BA and TSP, who in turn are required to coordinate with their TOPs.</p>		
Manitoba Hydro		<p>If the redline changes are implemented, GOs are removed from R4, thereby removing the obligation for GOs to maintain their connection requirements. If GOs are included in FAC-001, they should be held accountable to the same level as TOs and should be required to maintain their connection requirements. Requiring a GO to maintain connection requirements would be especially beneficial to the GO themselves. In the majority of instances, any GO that is an Applicable Entity for FAC-001 would initially be inexperienced in performing interconnection studies and would benefit from regular and frequent review of their connection requirements as experience and expertise are gained.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees this is a complex issue and did its best to outline how it arrived at its position</p>		

Organization	Yes or No	Question 7 Comment
in the document titled " <a href="#">Technical Justification: FAC-001-1.</a> "		
SERC OC Standards Review Group		Please list the set of standards are you referencing.
<b>Response:</b> The SDT is referring to those standards posted for comment (FAC-001-1, FAC-003-X, FAC-003-3, and PRC-004-2.1).		
Constellation Power Source Generation, Inc.	Affirmative	Constellation appreciates and supports the work of the standard drafting team. We recognize the significant time invested by technical experts from industry to consider the appropriate application of reliability standards to address concerns raised about coverage of transmission at the generator interface. The drafting team analysis identified the standards in need of revision to appropriately address the reliability concerns raised. Please see more detailed comments submitted in the Project 2010-07 comment form submitted on November 18, 2011.
<b>Response:</b> Thank you for your comment and support.		
Infigen Energy US	Affirmative	Infigen finds the SDT supporting measures and analysis regarding FAC-003-3 to be appropriate, and believes that it is prudent for Generation Owners and Transmission Owners to manage vegetation maintenance records/inspections accordingly. We support maintaining "reasonable and appropriate" risk prevention measures to minimize encroachment that could trigger vegetation-related outages.
<b>Response:</b> Thank you for your comment and support.		
PPL EnergyPlus LLC	Affirmative	PPL Generation, LLC, on behalf of its NERC-registered subsidiaries, appreciates the effort by the Standard Development Team to address the GO-TO interface issues in a manner that enhances the reliability of the BES without adding unnecessary burden on Generators. As registered GOs/GOPs, the PPL Generation registered entities agree with the changes made by the SDT to these three standards. To the extent that GOs/GOPs are required to register as TOs/TOPs, PPL Generation would have

Organization	Yes or No	Question 7 Comment
		significant concerns with meeting the compliance requirements applicable to TOs in the standards included in the scope of this Project, as well as other TO/TOP requirements throughout other NERC standards.
<p><b>Response:</b> Thank you for your comment and support.</p>		
Puget Sound Energy, Inc.	Affirmative	The changes to this standard are minor, and seem to be centered around including "generator Interconnection facilities" to R2. This added phrase and the statement in 1.4 Data Retention "Generator Owner that owns a generation Protection System" seems to assume that the generator owner and generator interconnection facilities owner is always the same. This is not always the case, and will make this standard language confusing to prepare evidence for. A suggestion would be to revise the language to allow for a separate generator owner and generator interconnection facilities owner.
<p><b>Response:</b> Thank you for your comment. The SDT believes that the language makes clear that an entity need only be concerned with the Elements or Facilities that it owns.</p> <p>The SDT agrees with your comment regarding the language in the Data Retention section and has modified that section as follows: "The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation or generator interconnection Protection System..."</p>		
Southwest Transmission Cooperative, Inc. / ACES Power Marketing	Affirmative	We largely support the changes made by drafting team because we believe the drafting team has provided the best solution in face of a difficult problem. However, in general, we do not support registration of GOs and GOPs as TOs and TOPs or applicability of any TO/TOP requirements to the GO/GOP simply because they have a radial interconnection greater than one mile in length. While there may be some generators that own interconnecting facilities of significant length operated at a significant voltage that could impact BES reliability, we do not believe that the number of generating facilities that fit into that category is significantly large. When one considers that the majority of generators are still owned and operator by utilities that are also registered as a TO and TOP, there is only a minority subset of generators

Organization	Yes or No	Question 7 Comment
		<p>left that could be considered. NERC has the registration for this remaining set of generators and could use the data to evaluate how many of this remaining subset have interconnections owned by the generator that are substantial enough to affect reliability. It seems that NERC could determine the boundaries of this problem before registering anymore GOs and GOPs as TOs and TOPs or before applying additional requirements through this effort on the GOs and GOPs. Subjecting a GO/GOP to any TO/TOP standards requirements should require a clear demonstration of the reliability gap in each instance. Some additional changes are necessary to FAC-001.</p>
<p><b>Response:</b> Thank you for your comment and support. We are unsure as to what changes to FAC-001 you feel are necessary unless you are referring to comments stated previously.</p>		
<p>Ingleside Cogeneration LP (Occidental Chemical)</p>	<p>Yes</p>	<p>Although the SDT is nearing conclusion on the closing of reliability gaps, the unnecessary registration of GOs and GOPs as TOs and TOPs is far from resolved in our view. Ingleside Cogeneration’s concern is based upon NERC’s recent proposal to dictate an interim GO-TO interconnection solution which completely bypasses the Standards Development Process. Frankly, it seriously brings to question the nature of the consensus-driven process - which appears to be moving in a dictatorial direction.</p>
<p><b>Response:</b> Thank you for your comment and support.</p>		
<p>American Wind Energy Association</p>	<p>Yes</p>	<p>AWEA believes that the standards modifications proposed by the SDT should address any genuine reliability gap with regard to generator lead lines, rather than just perceived but unsupported threats. To that end, we support the approach that the SDT appears to be taking of modifying a limited number of applicable standards so that they apply to GO/GOP lead lines. In particular, we fully support the fact that the SDT recognizes that GO/GOPs should not automatically be required to register as TO/TOPs simply because of their ownership of generator lead lines. The SDT correctly recognizes that such registration should be done based on a case-by-case determination. As already noted, registering a GO/GOP as a TO/TOP may actually decrease reliability.</p>

Organization	Yes or No	Question 7 Comment
<b>Response:</b> Thank you for your comment and support.		
RES Americas Development	Yes	We believe that the standards modifications proposed by the SDT should address any genuine reliability gap with regard to generator lead lines, rather than just perceived but unsupported threats. To that end, we support the approach that the SDT appears to be taking of modifying a limited number of applicable standards so that they apply to GO/GOP lead lines. In particular, we fully support the fact that the SDT recognizes that GO/GOPs should not automatically be required to register as TO/TOPs simply because of their ownership of generator lead lines. The SDT correctly recognizes that such registration should be done based on a case-by-case determination. As already noted, registering a GO/GOP as a TO/TOP may actually decrease reliability.
<b>Response:</b> Thank you for your comment and support.		
Southwest Power Pool Standards Development Team	Yes	
Northeast Power Coordinating Council, Northeast Power Coordinating Council	Yes	
MRO NSRF	Yes	
SERC Planning Standards Subcommittee	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
ACES Power Marketing	Yes	

Organization	Yes or No	Question 7 Comment
Standards Collaborators		
Electric Power Supply Association	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Exelon	Yes	
Seattle City Light	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
Ameren	Yes	
American Transmission Company	Yes	
Sempra Generation	Yes	
Xcel Energy	Yes	



Organization	Yes or No	Question 7 Comment
Cowlitz County PUD	Yes	
Constellation Power Source Generation	Yes	
Puget Sound Energy, Inc.		
Compliance & Responsibility Organization		
Bonneville Power Administration		
South Carolina Electric and Gas		
Consolidated Edison Co. of NY, Inc.		
Entergy Services		
ReliabilityFirst		
Tennessee Valley Authority		

**8. If you answered “yes” to Question 7, are the modifications the SDT has made in this posting the appropriate ones?**

**Summary Consideration:**

The SDT thanks all stakeholders for their comments. In this section, commenters either offered their support or directed the SDT to their comments on other questions in this report.

Organization	Yes or No	Question 8 Comment
Ameren	No	Please refer to our comments in responses to #3, #4, and #5 above.
<b>Response:</b> Please see the SDT’s responses to Questions 3, 4, and 5.		
Texas Reliability Entity	No	See comment 6.
<b>Response:</b> Please see the SDT’s response to Question 6.		
Ingleside Cogeneration LP (Occidental Chemical)	No	See comments to questions 1 through 4.
<b>Response:</b> Please see the SDT’s responses to Questions 1-4.		
SERC Planning Standards Subcommittee	No	See our comments above for question # 3.
<b>Response:</b> Please see the SDT’s response to Question 3.		
South Carolina Electric and Gas	No	The modifications are appropriate with the exception noted in question #3.
<b>Response:</b> Please see the SDT’s response to Question 3.		
ACES Power Marketing	No	The modifications are largely the appropriate ones with the exceptions we noted in Q1

Organization	Yes or No	Question 8 Comment
Standards Collaborators		and Q10.
<b>Response:</b> Please see the SDT’s responses to Questions 1 and 10.		
Southwest Power Pool Standards Development Team	No	We agree that the standards being addressed are correct. See above comments. There are some issues with the determination of which facilities are deemed BES since ownership of what may be a BES facility may not always be by a Transmission Owner. All relevant standards should apply to BES facilities regardless of ownership.
<b>Response:</b> Thank you for your comment.		
PSEG	No	
<b>Response:</b>		
SERC OC Standards Review Group		See comments on Question 7. If the standards referenced in question 7 are FAC-001, FAC-003 and PRC-004, we would answer yes to this question.
<b>Response:</b> Thank you for your comment and support.		
Southern Company	Yes	“The version history table is incorrect - change version 3 to version 2.1.”
<b>Response:</b> Thank you for your comment. We have made this change.		
RES Americas Development/ American Wind Energy Association	Yes	For the most, we agree that the SDT proposal strikes a reasonable balance and provides the requisite level of clarity and certainty necessary for GO/GOPs to understand their responsibilities and compliance requirements.
<b>Response:</b> Thank you for your comment and support.		
MRO NSRF	Yes	The NSRF agrees if the drafting team incorporates as suggested improvements

Organization	Yes or No	Question 8 Comment
<b>Response:</b> Thank you for your comment and support.		
Northeast Power Coordinating Council, Northeast Power Coordinating Council	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
Electric Power Supply Association	Yes	
American Electric Power	Yes	
BP Wind Energy North America Inc.	Yes	
Exelon	Yes	
Seattle City Light	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
American Transmission	Yes	

Organization	Yes or No	Question 8 Comment
Company		
Sempra Generation	Yes	
Xcel Energy	Yes	
Cowlitz County PUD	Yes	
Constellation Power Source Generation	Yes	

**9. If you answered “no” to Question 7, what standards need to be added or removed to achieve the SDT’s goal? Please provide technical justification for your answer.**

**Summary Consideration:**

The SDT thanks all stakeholders who submitted comments. Few stakeholders suggested that standards need to be added or removed to achieve the SDT’s goal.

One commenter pointed out that PRC-005-1a required the same kind of change made in the proposed PRC-004-2.1a to ensure that generator interconnection Facility Protection Systems are included within that standard. The SDT agrees with this suggestion and has initiated a process to modify R1 and R2 in PRC-005-1a.

A few commenters returned to FAC-001-1 and stated their concern about the feasibility of adding FAC-001-1 to the applicability section of this standard. The SDT agrees with commenters that the issues surrounding the interconnection of a third party Facility to a GO’s existing Facilities are complex ones, and reminded commenters that it did its best to address these complexities in the resource document titled “[Technical Justification: FAC-001-1](#).” The SDT also points out that if the GO is part of an RTO, then the GO will be coordinating any interconnection studies either directly or indirectly with the RTO interconnection process. If the GO is not part of an RTO, then the GO will be required to follow the pro forma interconnection procedures from Order 2003. The Order 2003 procedures require the GO to coordinate any studies with an affected system which could include Facilities owned by one, or more, TO on the other side of the GO’s existing point of interconnection. The SDT acknowledges that upon interconnection of a third party, other standards or registrations may apply as appropriate.

Some commenters suggested that the SDT reexamine the standards cited in the Milford and Cedar Creek FERC orders. The SDT continues to find clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards and not requiring the GO or GOP to register as a TO or TOP. However, to address stakeholder concern, the SDT has expanded its technical justification document (posted under “Supporting Materials”) to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive.

Organization	Yes or No	Question 9 Comment
Cowlitz County PUD	No	N/A
Manitoba Hydro	No	See question 7 comments.

Organization	Yes or No	Question 9 Comment
<p><b>Response:</b> See the SDT’s response to Question 7.</p>		
<p>Southern Company</p>	<p>Yes</p>	<p>Southern does not think that the revision to FAC-001-1 is necessary. A Generator Owner (GO) cannot assess reliability impacts to the Bulk Electric System (BES) and determine acceptability without support and involvement of the applicable owner and operator of the Transmission System (i.e., the “interconnected TO” or “interconnected TP”). A generator tie-line does not equate to a Transmission System. A GO must already adhere to a TO’s Facility connection requirements whether the GO wants to connect additional facilities or a third parties’ facilities to its own interconnection Facilities. Stated another way, the GO does not need Facility Connection requirements to govern how multiple units are tied to a collector bus so why are they needed for a third party to connect to an existing tie-line? In either case it is the interconnected TO or interconnected TP that has connection requirements that must be fulfilled. The GO’s Interconnection Agreement would prohibit it from connecting additional facilities without a new application for Interconnection Service with its interconnected TO or interconnected TP. A GO should not need to develop “connection requirements” unless it is in the business of owning and operating facilities independently of its interconnected TO or interconnected TP. We do not believe a reliability gap exists in FAC-001-1 because the requestor for interconnecting another Facility to an existing generation Facility must coordinate with the applicable TO, TP, and PA in accordance with FAC-002-0 to ensure they meet all applicable facility connection and performance requirements. If and when there is an agreement in place for a third party to connect to a generator tie-line then the tie-line would become part of the integrated system and its purpose and the owner’s function would likely warrant registration as a TO/TOP and FAC-001 would then apply. The following excerpt from the 2010-07 Background Resource White Paper acknowledges that this may be necessary: “The drafting team also acknowledges that, if another party interconnects to a Facility owned by a Generator Owner, there may be the need to address MOD or TPL standards. However, the drafting team believes that this, too, is best handled through specific evaluation, perhaps accompanied by changes to the</p>

Organization	Yes or No	Question 9 Comment
		<p>compliance registry. Entities that face this kind of scenario may also meet criteria applicable to other registrations such as Transmission Service Provider or Transmission Planner.” [Arguments related to jurisdictional, interconnection policy and open access transmission tariff issues](1) Because of (a) jurisdiction under Section 215, (b) FERC’s interconnection policy, and (c) the requirements of the pro forma open access transmission tariff (OATT), a GO should not be required to comply with FAC-001-1 until that GO’s generating Facility reaches commercial operation. NERC should not make facilities subject to the mandatory reliability standards before the facilities are actually part of the BES.(a) Jurisdiction under FPA Section 215. First, it is not clear that NERC or FERC has jurisdiction under FPA Section 215 to require generation facilities that have not actually reached commercial operation to be subject to reliability standards. Section 215(a)(2) of the FPA defines the “Electric Reliability Organization” as “the organization certified by the Commission ... the purpose of which is to establish and enforce reliability standards for the bulk-power system, subject to Commission review.” Further, (a)(3) provides that “The term ‘reliability standard’ means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system. The term includes requirements for the operation of existing bulk-power system facilities ... the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system ....” Thus, under Section 215 NERC can develop reliability standards that address requirements for existing bulk-power system facilities (i.e., facilities that have reached “commercial operation”) and for the design of planned additions or modifications. It is logical to interpret the phrase “design of new facilities” as meaning that new facilities must be designed to comply with existing reliability standards. However, it is not clear that this provision should be interpreted as requiring that a generating facility that has not yet reached commercial operation should be subject to reliability standards (including audit and penalties). Therefore, the GO with the existing generation facilities should not be required to incorporate the proposed generation facility into its Facility connection requirements before the proposed generation facility is subject to NERC or FERC jurisdiction. (b) FERC’s</p>



Organization	Yes or No	Question 9 Comment
		<p>interconnection policy. In addition, the revised FAC-001 would appear to place restrictions on interconnection customers in contravention of Order Nos. 2003 and 2006 (Standard Large and Small Interconnection Procedures and Agreements). FERC was very concerned about the ability of interconnection customers to interconnect their generating facilities and gave them a fair amount of flexibility. However, this revised FAC-001 would appear to restrict some of this flexibility.(i) Order No. 2003 gives the interconnection customer the ability to terminate a proposed interconnection on ninety days notice. Therefore, the interconnection customer is not required to build the facility. However, this revised FAC-001 appears to assume that the interconnection customer does not have this flexibility. What if the interconnection customer (the GO building a new generator on its site or the third party building a new generation facility) decides to terminate the Large Generator Interconnection Agreement (LGIA) or not proceed with the generation facility? In such event, the GO may be required to revert to its previous Facility connection requirements in order to accommodate the original configuration. (ii) The LGIA permits modifications to the proposed interconnection. How would this affect the Facility connection requirements? How long would the GO have to revise its Facility connection requirements? In the event that there is a single modification, or perhaps multiple modifications, how does the GO stay in compliance with this standard? (iii) FAC-001-1, R4 provides that each GO with Facility connection requirements and each TO shall maintain Facility connection requirements and make documentation of these requirements available to users of the Transmission System upon request. However, Large Generator Interconnection Procedures (LGIP), Section 3.4 requires the posting of certain interconnection information but the identity of the interconnection customer is not to be disclosed (unless it is an Affiliate). Requirement R4 would appear to potentially require disclosure of information and (more importantly) of the interconnection customer's identity in contravention of the requirements in Order No. 2003 and the LGIP.(c) OATT requirements. The definition of “applicable Generator Owner” (Section 4.2.1) and Requirement R2 provide that the GO will have an executed Agreement to evaluate the impact of interconnecting a new facility to the GO’s</p>

Organization	Yes or No	Question 9 Comment
		<p>existing generation facility. This statement is ambiguous. This statement could be understood to mean that the GO of the existing generation Facility will enter into an Agreement with the GO proposing to interconnect and the existing GO will evaluate the impact of the proposed interconnection. However, requests to interconnect new generation are processed under an OATT. In that case, it would be the Transmission Provider (not the existing GO) that would evaluate the impact of interconnecting the new facility. Thus, the language in FAC-001-1 would need to be revised to clarify that the owner of the new facility will need to interconnect under the OATT of an appropriate Transmission Provider (i.e., the Transmission Provider to which the existing GO is interconnected, not with the existing GO). Therefore, the owner of the new facility will most likely be the entity with the executed Agreement (with the Transmission Provider). Another consideration is that the existing GO could be developing a merchant transmission line. In that case, the existing GO would need to evaluate whether it needs have its own OATT and OASIS. In that case, the new generator owner would be interconnecting to the existing GO. However, the existing GO's line would not be a generator tie-line. This issue is not clear from the draft standard. (2) The following are suggested changes to FAC-001-1. (a) We recommend the Purpose statement be revised to state, "To avoid adverse impacts on BES reliability..." (b) It is unclear in Applicability section 4.2.1 that the term "Agreement" means that the GO has an executed agreement with a TO/TSP or that the GO and the third party have an executed agreement. Without further explanation, the capitalized term "Agreement" has the effect of introducing confusion. If the SDT does not intend to propose a new addition to the NERC Glossary of Terms, it should use the lower case term, "agreement." With respect to the capitalized term, "Transmission System," the SDT should consider clarifying if it intends to propose adding this to the Glossary. (3) Effect of the proposed revisions to FAC-001-1 on FAC-002-1.(a) As drafted, there are scenarios under which a new GO may attempt to interconnect to an existing GO even though, as explained above, the interconnection should actually be done to the appropriate Transmission Provider. If the appropriate Transmission Provider is not included in the evaluation of the interconnection various types of harm may occur. In</p>

Organization	Yes or No	Question 9 Comment
		<p>such event, the TPs and PAs should be indemnified from any liability with respect to performance of the evaluations required by FAC-002. (b) FAC-001 and FAC-002 should be revised to be clear that the existing GO and any new GOs must coordinate any interconnection with the appropriate Transmission Provider, TP and PA.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees this is a complex issue and did its best to outline how it arrived at its position in the document titled "<a href="#">Technical Justification: FAC-001-1.</a>"</p> <p>The SDT points out that if the GO is part of an RTO, then the GO will be coordinating any interconnection studies either directly or indirectly with the RTO interconnection process. If the GO is not part of an RTO, then the GO will be required to follow the pro forma interconnection procedures from Order 2003. The Order 2003 procedures require the GO to coordinate any studies with an affected system which could include Facilities owned by one, or more, TO on the other side of the GO's existing point of interconnection.</p> <p>The SDT does agree that upon interconnection of a third party, other standards or registrations may apply as appropriate.</p>		
PSEG	Yes	<p>We believe that the Ad Hoc Group's suggestions regarding PRC-005-1 - Transmission and Generation Protection System Maintenance were correct and that this standard should have been modified by the SDT in a manner similar to the way the SDT modified PRC-004-2. This would require modifying R1 and R2 in PRC-005-1a (the current version) to include protection systems in the generator interconnection Facility. In addition, the SDT should evaluate modifying PER-002-0 - Operation Personnel Training. In doing so the SDT completes one of the open FERC directives in Order 693. Paragraph 1363 addresses GOP training:1363. Further, the Commission agrees with MidAmerican, SDG&amp;E and others that the experience and knowledge required by transmission operators about Bulk-Power System operations goes well beyond what is needed by generation operators; therefore, training for generator operators need not be as extensive as that required for transmission operators. Accordingly, the training requirements developed by the ERO should be tailored in their scope, content and duration so as to be appropriate to generation operations personnel and the objective of promoting system reliability. Thus, in addition to modifying the Reliability Standard to identify generator operators as applicable entities, we direct the ERO to develop specific Requirements addressing the scope,</p>

Organization	Yes or No	Question 9 Comment
		content and duration appropriate for generator operator personnel.
<p><b>Response:</b> Thank you for your comment. The SDT agrees with the comment concerning PRC-005-1a and will be initiating a process to make that change.</p> <p>With respect to PER-002-0, the SDT continues to find that there are no clear and technical reliability reasons that support adding GOP requirements to any PER standard <i>based on the fact that the GOP operates a generator interconnection Facility</i>. While the SDT does not necessarily disagree that some training requirements for GOPs may be necessary, it does not see how these changes fall within its scope.</p>		
Ingleside Cogeneration LP (Occidental Chemical)		Ingleside Cogeneration LP believes that the set of standards proposed by the SDT is technologically accurate and defensible. The open issue is if the ERO and FERC expect more standards to be included - whether based upon sound reliability principals or not.
<p><b>Response:</b> Thank you for your comment and support.</p>		
Western Electricity Coordinating Council		Please see response to question #7.
<p><b>Response:</b> See the SDT's response to Question 7.</p>		
Texas Reliability Entity		See comment 6.
<p><b>Response:</b> See the SDT's response to Question 6.</p>		
SERC OC Standards Review Group		See comments on Questions 7 & 8.
<p><b>Response:</b> See the SDT's responses to Questions 7 and 8.</p>		
Florida Municipal Power		see response to Question 7

Organization	Yes or No	Question 9 Comment
Agency		
<p><b>Response:</b> See the SDT’s response to Questions 7.</p>		
Manitoba Hydro		<p>The revision to FAC-001-1 R2 may be problematic, depending on what was intended. Under the revised requirement, the obligation to comply is dependent on the execution of an agreement to evaluate reliability impacts under FAC-002-1. However, FAC-002-1 does not clearly require the execution of an agreement by the Generator Owner. FAC-002-1 only requires the Generator Owner to “coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority”. Accordingly if a Generator Owner coordinates without executing an agreement to perform an assessment, compliance with FAC-001 R1 will not be required.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees this is a complex issue and did its best to outline how it arrived at its position in the document titled “<a href="#">Technical Justification: FAC-001-1</a>.”</p>		
Southwest Power Pool Regional Entity		<p>The SDT should consider the standards that FERC identified in 135 FERC ¶ 61,241.</p>
<p><b>Response:</b> Thank you for your comment. The NERC <a href="#">Standard Processes Manual</a> does not address the issue of how to deal with FERC Orders (that don’t include explicit directives). However, based on your and other comments, we have expanded our technical justification document (posted under “Supporting Materials”) to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.</p>		

## 10. Do you have any other comments that you have not yet addressed? If yes, please explain.

### Summary Consideration:

The SDT thanks all stakeholders for their comments. In this section, many stakeholders offered supportive comments. Others offered a variety of suggestions, many of which were addressed.

One commenter suggested that the word “system” should not be capitalized in “Transmission System” in FAC-001-1 because the NERC glossary term “System” does not apply within the standard. The SDT agreed with this suggestion, and changed all references to “Transmission System” to “interconnected Transmission systems” for consistency in other parts of the standard and with FAC-002. Another commenter pointed out that “within” should be “with” in Section 4.2.1, and the SDT made this change.

A few commenters repeated their concern with the exclusion in FAC-003 for GOs with specific kinds of interconnection Facilities. For these commenters, the SDT reemphasized that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.

To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: ~~“Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are...”~~

Some stakeholders offered comments that were outside the scope of this SDT’s work. A few offered comments on the overall strategy of the FAC-003-2 standard, and the SDT informed them that these comments should have been submitted when the Project 2007-7 Vegetation Management posted its work for comment.

One commenter suggested changes to the VSLs for R1 and R4. Because the SDT made no changes to these requirements, modifying the VSLs for these requirements is outside the scope of this team. This item will be added to the issues database.

Several stakeholders suggested the SDT review the standards cited in the draft NERC directive regarding generator interconnection leads and in the FERC orders regarding Milford and Cedar Creek. The SDT continues to find clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards and not requiring the GO or GOP to register as a TO or TOP. However, to address stakeholder concern, the SDT has expanded its

technical justification document (posted under “Supporting Materials”) to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive.

Organization	Yes or No	Question 10 Comment
Gainesville Regional Utilities	Negative	<p>1. It would seem that the impetus for FAC003 is to eliminate vegetation related outages within the rights-of-way as defined and subject to the exclusions as stated in footnote</p> <p>2. Thus the requirement is to manage the ROW to prevent vegetation related sustained outages with the measure being no outages. With grow-ins and fall-ins from within the defined ROW being controllable factors. 2. Including encroachments leaves the door open for fines to be imposed with no actual outage(s) having occurred. This may be like being found guilty of a crime that has not yet taken place.</p> <p>3. Combine vegetation related sustained outages by “grow-ins” and “blowing together of lines and vegetation located inside the ROW” as one item as they are both consequences of the growth of vegetation either vertically and horizontally.</p> <p>4. Leave vegetation related sustained outages by “fall-in” as a standalone as this will be related to structural problems occurring from a variety of sources.</p> <p>5. Combine R3 and R7 to R1 (development and implementation of a Transmission Vegetation Management Plan which shall include documented maintenance strategies or procedures or processes or specifications, delineation of an annual work plan and completion of same). Thus this would be the competency based requirements as a program without execution is meaningless.</p> <p>6. R1 and R2 become R2 and R3.</p>
<p><b>Response:</b> Thank you for your comment. This is outside the scope of the <a href="#">SAR</a> for this project. This SDT did review comments submitted as part of the <a href="#">Project 2007-07</a> effort and found that a response to this comment was provided. No change made.</p>		
Northern Indiana Public Service Co.	Negative	Ballot needs work

Organization	Yes or No	Question 10 Comment
<p><b>Response:</b> The SDT does not understand your specific concern.</p>		
<p>PSEG Energy Resources &amp; Trade LLC, PSEG Fossil LLC, Public Service Electric and Gas Co.</p>	<p>Negative</p>	<p>FAC-003-X is not applicable since FAC-003-2 was approved by the BOT on November 4, 2011</p>
<p><b>Response:</b> Thank you for your comment. You are correct that in November 2011, NERC’s Board of Trustees adopted FAC-003-2 – Transmission Vegetation Management (developed under Project 2007-07 Vegetation Management). Based on this approval, NERC staff will file FAC-003-2 with the applicable regulatory authorities. The Project 2010-07 SDT will move forward with ballots for both FAC-003-3 (proposed changes to the BOT-adopted FAC-003-2) and FAC-003-X (proposed changes to the FERC-approved FAC-003-1) with the intention of eventually only filing FAC-003-3. The SDT has elected to carry FAC-003-X through to ballot because if FAC-003-2 and FAC-003-3 are not approved by FERC, the SDT wants to be ready to file FAC-003-X to ensure that there is a functional entity responsible for managing vegetation on the piece of line commonly known as the generator interconnection Facility.</p> <p>Note that for its recirculation ballot, the SDT will be balloting <b>both</b> FAC-003-3 and FAC-003-X, but stakeholders should <b>not</b> vote as though they are choosing one or the other. As stated above, the SDT plans to present FAC-003-3 alone to NERC’s Board of Trustees, but it wants to have FAC-003-X ready to submit to the Board if, for some reason, neither FAC-003-2 nor FAC-003-3 are approved by FERC. Members of the ballot body should vote on the merits of each version of FAC-003 individually. <b>In other words, stakeholders who support adding GOs to the applicability of FAC-003 should vote in the affirmative for both FAC-003-3 and FAC-003-X.</b></p>		
<p>Hydro-Quebec TransEnergie</p>	<p>Negative</p>	<p>Hydro-Quebec TransEnergie is casting a negative vote again because our comment from the last posting was not considered in the current draft: The minimum frequency of Vegetation Inspection should be based upon an average growth rates of smaller regions than all North America. Example, above the latitude of 50 degrees North, the vegetation growth rates is limited. The Vegetation Inspection frequency in the territories located above 50 degrees of latitude must be relaxed to 3 years.</p>
<p><b>Response:</b> Thank you for your comment. This is outside the scope of the <a href="#">SAR</a> for this project. This SDT did review comments submitted as part of the <a href="#">Project 2007-07</a> effort and did not find this comment had been submitted as part of that project effort. No changes made.</p>		



Organization	Yes or No	Question 10 Comment
New Brunswick System Operator	Negative	Since NBSO voted 'affirmative' for FAC-003-3, it makes sense for us to vote 'negative' for this standard.
<p><b>Response:</b> Thank you for your comment. In November 2011, NERC’s Board of Trustees adopted FAC-003-2 – Transmission Vegetation Management (developed under Project 2007-07 Vegetation Management). Based on this approval, NERC staff will file FAC-003-2 with the applicable regulatory authorities. The Project 2010-07 SDT will move forward with ballots for both FAC-003-3 (proposed changes to the BOT-adopted FAC-003-2) and FAC-003-X (proposed changes to the FERC-approved FAC-003-1) with the intention of eventually only filing FAC-003-3. The SDT has elected to carry FAC-003-X through to ballot because if FAC-003-2 and FAC-003-3 are not approved by FERC, the SDT wants to be ready to file FAC-003-X to ensure that there is a functional entity responsible for managing vegetation on the piece of line commonly known as the generator interconnection Facility.</p> <p>Note that for its recirculation ballot, the SDT will be balloting <b>both</b> FAC-003-3 and FAC-003-X, but stakeholders should <b>not</b> vote as though they are choosing one or the other. As stated above, the SDT plans to present FAC-003-3 alone to NERC’s Board of Trustees, but it wants to have FAC-003-X ready to submit to the Board if, for some reason, neither FAC-003-2 nor FAC-003-3 are approved by FERC. Members of the ballot body should vote on the merits of each version of FAC-003 individually. <b>In other words, stakeholders who support adding GOs to the applicability of FAC-003 should vote in the affirmative for both FAC-003-3 and FAC-003-X.</b></p>		
PSEG Energy Resources & Trade LLC/ Public Service Electric and Gas Co./ PSEG Fossil LLC	Negative	The phrase “generator Facility” should be “generator Transmission Facility,” and the phrase “Transmission System” should be “Transmission system.”
<p><b>Response:</b> Thank you for your comment. We agree with your change to “Transmission system” but not to the addition of “Transmission” in the phrase “generator Facility.” The SDT does not agree with labeling a GO’s Facility as “Transmission,” in part because in some areas (like Texas), GOs, by statute, can’t own Transmission. It was also brought to the SDT’s attention that in most cases, the Facility in question is referred to as the Interconnection Facility in documents filed by the GO with FERC. Therefore, the SDT intentionally modified language so that a Facility owned by a generation entity did not contain the term “Transmission.”</p>		
SERC Reliability Corporation	Negative	There should not be a weak link under the standard. This proposed revision would create a weak-link where a portion of the otherwise covered right-of-way would be exposed.

Organization	Yes or No	Question 10 Comment
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled "<a href="#">Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface</a>," the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: <del>"Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are..."</del>.</p>		
<p>New York State Department of Public Service/ National Association of Regulatory Utility Commissioners</p>	<p>Negative</p>	<p>Understand that there is an open issue regarding the availability of generation compliance documentation that needs to be satisfactorily addressed.</p>
<p><b>Response:</b> The SDT does not understand your specific concern.</p>		
<p>Infigen Energy US</p>	<p>Affirmative</p>	<p>Infigen supports the efforts of the SDT to ensure that Protection System Misoperations affecting the reliability of the BES are thoroughly analyzed and mitigated. Generator Owners are already analyzing Misoperations as/if they occur, and are employing Corrective Action Plans to avoid future Misoperations. We support maintaining "reasonable and appropriate" preventative measures and risk assessment tools to ensure that misoperations are evaluated and corrected expediently.</p>
<p><b>Response:</b> Thank you for your comment and support.</p>		
<p>PPL EnergyPlus LLC/PPL NERC Registered Affiliates</p>	<p>Affirmative</p>	<p>PPL Generation, LLC, on behalf of its NERC-registered subsidiaries, appreciates the effort by the Standard Development Team to address the GO-TO interface issues in a manner that enhances the reliability of the BES without adding unnecessary burden on Generators. As registered GOs/GOPs, the PPL Generation registered entities agree with the changes made by the SDT to these three standards. To the extent that GOs/GOPs are required to register as TOs/TOPs, PPL Generation would have</p>

Organization	Yes or No	Question 10 Comment
		significant concerns with meeting the compliance requirements applicable to TOs in the standards included in the scope of this Project, as well as other TO/TOP requirements throughout other NERC standards.
<b>Response:</b> Thank you for your comment and support.		
SERC Reliability Corporation	Affirmative	The Generator Owner may be required to self-certify and report periodically to the region whether they have become applicable to the standard.
<b>Response:</b> Thank you for your comment and support.		
Southwest Transmission Cooperative, Inc./ ACES Power Marketing Standards Collaborators/ ACES Power Marketing	Affirmative	The modifications to PRC-004-2.1 R2 could be interpreted as requiring the GO to analyze Protection System Misoperations on the generator interconnection Facility even if it does not own the Facility. We suggest modifying the requirement as shown below to address this issue.”The Generator Owner shall analyze Protection System Misoperations on its generator and generator interconnection Facility that it owns ...”
<b>Response:</b> Thank you for your comment. The SDT believes that the language makes clear that an entity need only be concerned with the Elements or Facilities that it owns.		
SERC Reliability Corporation	Affirmative	With the understanding the Generator Interconnection FACilities will be grouped with Transmission Protection Systems for analysis at the regional level.
<b>Response:</b> Thank you for your comment and support.		
Entergy Services		We suggest that the Vegetation Management Standards should be consistent for both the TO and GO facilities. We would also like to suggest an additional Recommendation for added clarity regarding Category 3 Outages (Off-ROW Fall-in Outages). We understand that the Category 3 Outages are not a violation of the Standard, but we feel that there should be some level of comment added within the Standard clearly stating that these Outages are “Reportable Only” during the

Organization	Yes or No	Question 10 Comment
		<p>Quarterly Outage reports to the RE's, and that there are no associated violations/sanctions for this Category Of Outage, and that an Off-ROW fall-in outage would not be considered an encroachment into the MVCD in any way. The Technical Reference Document does a good job of clearly stating this in the Introduction on Page 5 ("This standard is not intended to address outages such as those due to vegetation fall-ins or blow-ins from outside the Right-of-Way, vandalism, human activities or acts of nature.") and we feel that this should also be stated clearly in the Standard.</p>
<p><b>Response:</b> Thank you for your comment. As it discusses in the document titled "<a href="#">Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface</a>," the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.</p> <p>To clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight: <del>"Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are..."</del>.</p> <p>The remainder of your comment is outside the scope of this SDT.</p>		
Southern Company		<p>We agree with the 2010-17 Standard Drafting Team's conclusion to not modify other standards such as those mentioned on page 4 of the Technical Justification document. In addition, we wish to provide the following support for exclusion of these specific standards. Southern Company believes NERC's Project 2010-07 SDT must challenge making revisions to the standards included in the FERC order on Cedar Creek and Milford. (This order supports NERC's requirement for those entities to register as a TO/TOP due to their ownership of generator interconnection circuits &gt; 100kV.) We believe there are clear technical and reliability-based reasons that support not adding GO and GOP requirements to these standards and not requiring the GO or GOP to register as a TO or TOP. Furthermore, we also believe there are clear distinctions between GO/GOP responsibilities and TO/TOP responsibilities that must be</p>

Organization	Yes or No	Question 10 Comment
		<p>maintained to ensure BES reliability. Revising standards to assign TO/TOP responsibilities to a GO/GOP or requiring a GO/GOP to register as a TO/TOP because of generator interconnection circuits &gt; 100kV will reduce the clarity of these responsibilities. We have provided specific comments on each standard below:</p> <p>EOP-005-1 R1, R2, R6, R7R1 and R2 require each TOP to have and maintain a system restoration plan. R6 requires the TOP to train its operating personnel in implementing this plan. R7 requires the TOP to verify its restoration plan by actual testing or simulation. These requirements are clearly the role and responsibility of the TOP, not a GO/GOP who happens to have generator interconnection facilities in the TOP's control area. The GOP's roles and responsibilities are clearly and appropriately addressed EOP-005-2. The presence of a generator interconnection circuit &gt; 100kV that happens to be owned by the GO instead of the TOP fundamentally does not change the roles and responsibilities of the TOP or the GOP. Thus, no changes due to EOP-005 are needed.</p> <p>FAC-014-2, R2: FAC-014-2 R2 states "The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology." FAC-014-2 R2 should not be revised to include GOPs. The GO is required by FAC-008-1 R1 and FAC-009-1 (FERC approved version) and pending FAC-008-3 R3 and R6 (FAC-008-3 filed with FERC for approval) to document the Facility Ratings for a GO-owned generator interconnection circuit &gt;100kV. The established Facility Rating must respect the most limiting applicable equipment rating in the circuit and must consider operating limitations and ambient conditions. The thermal or ampere rating of this circuit would equal its ampere operating limit and should be conveyed by the GO to the GOP if they are not the same entity. The operating voltage limits for this circuit are established by the applicable TO/TOP, not the GO or GOP. Therefore, we believe adding the GO to FAC-014-2 R2 would be redundant.</p> <p>PER-003-1 R2, R2.1, R2.2PER-003-1 R2 and its sub-requirements state:"R2. Each Transmission Operator shall staff its Real-time operating positions performing</p>

Organization	Yes or No	Question 10 Comment
		<p>Transmission Operator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates (1 ) : [Risk Factor: High][Time Horizon: Real-time Operations]: R2.1. Areas of Competency R2.1.1. Transmission operations R2.1.2. Emergency preparedness and operations R2.1.3. System operations R2.1.4. Protection and control R2.1.5. Voltage and reactive R2.2. Certificates o Reliability Operator o Balancing, Interchange and Transmission Operator o Transmission Operator This requirement is specifically for TOPs. Personnel training for GOPs needs to be addressed separately and not mingled with responsibilities of the TOP. The GOPs role in supporting BES reliability needs to be clearly understood and defined prior to establishing training requirements in the standards.</p> <p>PRC-001-1, R2, R2.2, R4, R6Generator Operators (GOPs) and the scope of protection equipment for generation interconnection Facilities are already appropriately accounted for in this standard in requirement R2 and sub-requirement R2.2 The language used in requirement R2 which applies to the GOP uses the general terms “relay or equipment failures” which would include not only generator relaying, but generator interconnection relaying in the GOPs scope as well. The GOP is required to notify the TOP and Host BA in R2.1 “if a protective relay or equipment failure reduces system reliability.” Requirement R2.2 requires the affected TOP to notify its RC and affected TOPs and BAs. Thus, applying R2.2 to a GOP would be redundant to R2.1. Requirement R4 states, “Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.” A generator interconnection tie line does not constitute a ‘major tie line” or major “interconnection with neighboring GOPs, TOPs, and BAs.” Thus, R4 should not be revised to include GOPs. If a GO exists within NERC that does own such interconnection facilities, the responsibility for coordination of protection systems on such a line or interconnection should be the responsibility of the TOP in that area, not the GO/GOP. This may require formal agreements between the TO/TOP and GO/GOP, since the GO may own protection equipment on his end. The same logic applies to</p>

Organization	Yes or No	Question 10 Comment
		<p>R6. R6 states, “Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.” This is clearly the responsibility of the TOP and/or BA, not a GO/GOP who happens to have generator interconnection facilities in the area. An SPS function by definition is to maintain BES reliability. If a GO/GOP has equipment within the equipment scope of a Special Protection System (SPS), responsibility for monitoring the SPS should be conveyed in a formal agreement as appropriate.</p> <p>TOP-001-1 R1 Requirement R1 states, “Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.” This is clearly the responsibility of the TOP, not a GO/GOP who happens to have generator interconnection facilities in the TOP’s area. Thus, R1 should not be applied to a GO/GOP who owns or operates generator interconnection facilities. Furthermore, TOP-001-1 R3 (proposed to be covered in the future in the proposed IRO-001-2 R2 and R3) appropriately requires the GOP to comply with reliability directives issued by the TO “unless such actions would violate safety, equipment, regulatory or statutory requirements.” These requirements effectively give the TOP the necessary decision-making authority over operation of all generator Facilities up to the point of interconnection. They also give the GOP the necessary authority to take appropriate actions to ensure safety and protection of the GO’s equipment. Thus, no changes to TOP-001-1 are necessary.</p> <p>TOP-004-2 R6, R6.1, R6.2, R6.3, R6.4 Requirement R6 and its sub-requirements state: “R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: R6.1. Monitoring and controlling voltage levels and real and reactive power flows. R6.2. Switching transmission elements. R6.3. Planned outages of transmission elements. R6.4. Responding to IROL and SOL violations.” These are clearly</p>

Organization	Yes or No	Question 10 Comment
		<p>the responsibility of the TOP, not a GO/GOP who happens to have generator interconnection facilities in the TOP’s area. Thus, these requirements should not be applied to a GO/GOP who owns or operates generator interconnection facilities. The same logic applies here as stated above in our discussion on TOP-001-1. We believe it is inappropriate and would be adverse to BES reliability to apply these requirements to a GOP. TOP-004-2 effectively gives the TOP the necessary decision-making authority over operation of all generator Facilities up to the point of interconnection. They also give the GOP the necessary authority to take appropriate actions to ensure safety and protection of the GO’s equipment, such as opening high voltage generator output breakers when required to protect the unit. Thus, no changes to TOP-004-2 are necessary. TOP-006-2 R3 Requirement R3 states, “R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel. The intent of this requirement when applied to a GOP is already addressed in PRC-001-1 R1 which states, “Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.” Thus, no change to TOP-006-2 is necessary. ”</p>
<p><b>Response:</b> Thank you for your comment and support. We agree that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards and not requiring the GO or GOP to register as a TO or TOP. We have expanded our technical justification document (posted under “Supporting Materials”) to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive, and many of your explanations are included therein.</p>		
<p>American Wind Energy Association</p>		<p>AWEA appreciates the opportunity to submit these comments on the NERC Project 2010-07. AWEA supports the general direction indicated by both the Generator Requirements at the Transmission Interface Ad Hoc Group and the Project 2010-07 Standards Development Team. We agree with the sentiments from both groups that a GO or GOP that also owns or operates a generator lead line should not be required to register as a TO or TOP strictly because they own or operate a generator lead line. We also agree that requiring these GO/GOPs to comply with all the TO/TOP standards</p>



Organization	Yes or No	Question 10 Comment
		<p>would have little effect on or benefits to reliability of the Bulk Electric System, and could even detract from it. AWEA supports the intent and goal of the SDT to ensure that all generator-owned Facilities are appropriately covered under NERC’s Reliability Standards. We also agree with the SDT that while many GO/GOPs operate Elements and Facilities that might be considered by some entities to be Transmission, these are most often radial Facilities that are not part of the integrated grid, and as such should not be subject to the same standards applicable to TO/TOPs, who own and operate Transmission Elements and Facilities that are part of the integrated grid. Therefore, we support the SDT’s approach of identifying a very limited number of TO/TOP standards, such as FAC-001 and FAC-003, which should also apply to GO/GOP owners of generator lead lines. We would be concerned, however, if additional requirements were added beyond FAC-001, FAC-003, and PRC-004. Consideration of any additional standards with respect to generator lead lines should be done on a standard-by-standard basis, reviewing the applicability of each standard as well as the impact on the reliability of the Bulk Electric System.</p>
<p><b>Response:</b> Thank you for your comment and support.</p>		
<p>Bonneville Power Administration</p>		<p>BPA thanks you for the opportunity to comment on Project 2010-07, Generator Requirements at the Transmission Interface. BPA stands in support of the proposed revisions and has no comments or concerns at this time.</p>
<p><b>Response:</b> Thank you for your comment and support.</p>		
<p>Constellation Power Source Generation</p>		<p>Constellation appreciates and supports the work of the standard drafting team. We recognize the significant time invested by technical experts from industry to consider the appropriate application of reliability standards to address concerns raised about coverage of transmission at the generator interface. The drafting team analysis identified the standards in need of revision to appropriately address the reliability concerns raised. While the revision process focuses on specific standards, it is important to consider the reliability questions in the context of the full complement</p>

Organization	Yes or No	Question 10 Comment
		<p>of reliability standards that apply to entities. For instance, the following standards already apply to generators and relate to the reliability considerations around transmission at the generator interface:</p> <ul style="list-style-type: none"> <li>o PRC-001-1 addresses coordination of protection system components by requiring all GOs to ensure coordination of their protection system with interconnected parties. Further, FAC-002 requires that all new facilities undergo reviews by the TOP, BA, etc.</li> <li>o PRC-004-1 requires all GOs to ensure that they analyze all misoperations on their protection system which would include the protection of the tie line.</li> <li>o TOP standards applicable to GOs aid coordination between a GO and a TO with regards to the generator tie line by requiring all GOs to coordinate all maintenance and emergency outages (both forced and planned) with all applicable interconnected parties. Further, all ISO procedures require the same of GOs.</li> <li>o RC, TOP and/or BA certified operators control and are responsible for overseeing that transmission. According to the NERC functional model, a Generator Operator is defined as “operat(ing) generating unit(s) and perform(ing) the functions of supplying energy and reliability related services.” Given this limited scope, the Generator Operator (GOP) cannot be considered as operating on the same level as the Reliability Coordinator, Transmission Operator or Balancing Authority when it comes to real time information on the status of the BES. The GOP does not monitor and control the BES, rather the GOP only monitors and controls the generators that it operates and relays information to other operating entities.</li> <li>o IRO and TOP standards applicable to GOs include tie lines in their pool of resources to alleviate operational emergencies by requiring all GOs to operate as directed by their TOP, BA, or RC as directed and must render emergency assistance.</li> <li>o FAC-8 and FAC-9 manage rating methodology consistency by requiring all GOs to develop a methodology to rate all equipment, and that the RC has the authority to challenge the GO on that methodology. The onus is on the GO to either change their methodology and rating accordingly, or provide a technical justification as to why</li> </ul>

Organization	Yes or No	Question 10 Comment
		they cannot adopt the changes. Further, a generator will never be limited by its tie line, as a generator’s profits are directly tied to its output. Therefore no generator would limit its facility to the equipment that is delivering that output.
<p><b>Response:</b> Thank you for your comment and support. We agree that it is important to consider the reliability questions in the context of the full complement of reliability standards, and we have endeavored to make these broader connections clear in our revised technical justification document (posted under “Supporting Materials”). That document has been expanded to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive, and the kinds of further justifications you also provided are included therein. After another thorough review of these standards, the SDT continues to believe that there are clear and technical reliability-based reasons that support not adding GO and GOP requirements to these standards.</p>		
Cowlitz County PUD		In answer to the SDT request for feedback on FERC's Order concerning Cedar Creek and Milford, the District finds no technical reason to add any of the listed standard requirements, and struggles to understand why FERC would even consider this listing as applicable.
<p><b>Response:</b> Thank you for your comment and support.</p>		
Southwest Transmission Cooperative, Inc.		In section 4.2.1 of the Applicability Section, “within” should be “with”. Because NERC’s Glossary of Terms establishes that an Agreement can be verbal and not enforceable by law, section 4.2.1 should be further modified to clarify that it is a legally enforceable and fully executed Agreement. The language in R3 in parenthesis after Generation Owner should be modified to “once required by Requirement R2”. This makes it clearer that R3 does not apply until the GO has an executed Agreement to evaluate a request by a third part to interconnect.
<p><b>Response:</b> Thank you for your comment. We agree that “within” should be “with.” The SDT chose not to adopt the second recommendation as the requirement already contains the term “executed.” The SDT also chose not to adopt the third recommendation as the requirement already contains the parenthetical (in accordance with Requirement R2) which we feel is synonymous with the comment.</p>		

Organization	Yes or No	Question 10 Comment
Manitoba Hydro		Manitoba Hydro would also like to point out that if the redline changes are implemented, it will greatly increase the complexity of coordination required under FAC-002-1 for Transmission Planners/Planning Authorities.
<p><b>Response:</b> Thank you for your comment. The SDT agrees this is a complex issue and did its best to outline how it arrived at its position in the document titled "<a href="#">Technical Justification: FAC-001-1.</a>"</p>		
Compliance & Responsibility Organization		<p>NextEra Energy, Inc. (NextEra) appreciates the work of the Project 2010-07 Generator Requirements at the Transmission Interface Standard Drafting Team (SDT) on a subject that NextEra has a significant interest in resolving. In fact, NextEra has been a member of the SDT and an active observer. Given the recent events - such as (a) the North American Electric Reliability Commission's draft interim directive; (b) the denial of the Milford and Cedar Cheek requests for reconsideration at the Federal Energy Regulatory Commission (FERC) and (c) the record in this case which, at times, suggests the SDT needs to more formally consider the Milford and Cedar Cheek Reliability Standards - NextEra requests that SDT more formally consider the merits of each Reliability Standard adopted the Milford and Cedar Cheek FERC orders and the NERC draft interim directive. Although NextEra does not condone the manner in which NERC issued the interim draft directive and stated so in its comments to NERC on the interim draft directive, NextEra's overarching objective on this issue is to bring a uniform, fair and technically supported approach that resolves the interface issue. Thus, NextEra requests that the SDT (prior to proceeding any further or any additional comments or votes on specific draft Reliability Standards) issue a technical paper that point-by-point addresses the merits of including the Reliability Standards set forth in the FERC Orders and NERC's draft interim directive, and request stakeholder, including NERC staff, comment. For example, this technical paper would likely the merits of NERC's draft interim directive not requiring NERC-certified operators (but require training of interface operators), while FERC's orders require NERC-certified operators. While NextEra does not agree five days of training is necessary for an interface operator, as the draft interim directive appears to propose, NextEra does</p>

Organization	Yes or No	Question 10 Comment
		<p>believe a technical case can be made why NERC-certification is not required, and that some degree of training related to the applicable Reliability Standards is reasonable. Similar, on FAC-003 (as well as several other Standards), the draft interim directive proposes a slightly different approach than the SDT. NextEra would rather these approaches reconciled than be in conflict, with the potential for continued conflict as the SDT's work product proceeds. Further, NextEra requests that the SDT's review the technical merits of NERC's proposed criteria to determine what generator transmission lead is required to comply with additional Reliability Standards. As noted, above, this technical paper should be posted for stakeholder, including NERC staff, comment. Accordingly, while NextEra would have preferred that NERC and the Regional Entities express there interim draft directive approach on the record in this proceeding, NextEra believes it is appropriate for the SDT to draft a comprehensive technical paper that, with an open approach, considers the inclusion of additional Reliability Standards, if appropriate, as a way of building lasting support for its approach.</p>
<p><b>Response:</b> Thank you for your comment and support. We certainly agree that is important for NERC staff and the SDT to continue to work together to try to develop a mutually agreed upon solution for dealing with this reliability gap, and to a certain extent, the SDT has tried to provide the kind of technical paper you suggest in its modified technical justification document (posted under "Supporting Materials"), which has been expanded to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive. The SDT does not, at this point, plan to develop a technical paper that discusses the merits of the standards introduced by FERC and NERC, because its current focus is on filing the FAC-001-1, FAC-003-3, and PRC-004-2.1a with FERC. As it moves forward to a final solution, however, this kind of technical paper may prove useful. We appreciate the suggestion.</p>		
Dominion		No
Tennessee Valley Authority		No
Exelon		<p>PRC-004 - suggest that the Standard state that responsibility for the analysis of missoperations of protective equipment shall be the responsibility of the owner of the protective equipment.</p>

Organization	Yes or No	Question 10 Comment
<p><b>Response:</b> Thank you for your comment and support. The SDT believes that the language makes clear that an entity need only be concerned with the Elements or Facilities that it owns.</p>		
ReliabilityFirst		<p>ReliabilityFist has found a number of editorial erros for the FAC-001-1 VSLs. They include the following:1. VSL R1 - should not reference sub-requirements, should reference the sub-parts consistent with the requirement (i.e. Requirement R1, Part 1.1, 1.2 or 1.3) 2. VSL for R3 - the VSL should referenced Requirement 3, Part 3.1.1 through 3.1.16 rather than what is currently stated (Requirement R3, Part 3.1.1 R3.1.6)</p>
<p><b>Response:</b> Thank you for your comment. While we agree that the VSLs for R1 need to be updated, that change is outside the scope of this SDT because our changes are limited to those that incorporate the GO into the applicability of the requirement; the team made no changes to R1 as it only includes the TO. We have, however, made the suggested changes to the VSLs for R3.</p>		
RES Americas Development		<p>RES and AWEA appreciates the opportunity to submit these comments on the NERC Project 2010-07. We support the general direction indicated by both the Generator Requirements at the Transmission Interface Ad Hoc Group and the Project 2010-07 Standards Development Team. We agree with the sentiments from both groups that a GO or GOP that also owns or operates a generator lead line should not be required to register as a TO or TOP strictly because they own or operate a generator lead line. We also agree that requiring these GO/GOPs to comply with all the TO/TOP standards would have little effect on or benefits to reliability of the Bulk Electric System, and could even detract from it. RES and AWEA supports the intent and goal of the SDT to ensure that all generator-owned Facilities are appropriately covered under NERC’s Reliability Standards. We also agree with the SDT that while many GO/GOPs operate Elements and Facilities that might be considered by some entities to be Transmission, these are most often radial Facilities that are not part of the integrated grid, and as such should not be subject to the same standards applicable to TO/TOPs, who own and operate Transmission Elements and Facilities that are part of the integrated grid. Therefore, we support the SDT’s approach of identifying a very limited number of</p>

Organization	Yes or No	Question 10 Comment
		TO/TOP standards, such as FAC-001 and FAC-003, which should also apply to GO/GOP owners of generator lead lines. We would be concerned, however, if additional requirements were added beyond FAC-001, FAC-003, and PRC-004. Consideration of any additional standards with respect to generator lead lines should be done on a standard-by-standard basis, reviewing the applicability of each standard as well as the impact on the reliability of the Bulk Electric System.
Sempra Generation		Sempra Generation also supports the comments, being concurrently filed, of the Electric Power Supply Association (EPSA).
<b>Response:</b> Thank you for your comment and support.		
Puget Sound Energy, Inc.		The changes to this standard are minor, and seem to be centered around including "generator Interconnection facilities" to R2. This added phrase and the statement in 1.4 Data Retention "Generator Owner that owns a generation Protection System" seems to assume that the generator owner and generator interconnection facilities owner is always the same. This is not always the case, and will make this standard language confusing to prepare evidence for. A suggestion would be to revise the language to allow for a separate generator owner and generator interconnection facilities owner.
<b>Response:</b> Thank you for your comment and support. The SDT believes that the language makes clear that an entity need only be concerned with the Elements or Facilities that it owns.		
SERC Planning Standards Subcommittee/ SERC OC Standards Review Group		The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers”
<b>Response:</b> Thank you for your comment and support.		

END OF REPORT



# Standards Announcement

## Project 2010-07 Generator Requirements at the Transmission Interface

Formal Comment Period Open March 9 – April 9, 2012

Successive Ballot Window Open March 30 – April 9, 2012

### [Available Now](#)

The Generator Requirements at the Transmission Interface drafting team has posted limited revisions to the Applicability sections of FAC-003-X—Transmission Vegetation Management Program and FAC-003-3—Transmission Vegetation Management, along with implementation plans, for parallel formal 30-day comment periods and successive ballots.

### Instructions for Commenting

Please use this [electronic form](#) to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at [monica.benson@nerc.net](mailto:monica.benson@nerc.net). An off-line, unofficial copy of the comment form is posted on the [project page](#).

### Special Instructions for Submitting Comments with a Ballot

Please note that comments submitted during the formal comment period and ballot for the standard all use the same electronic form, and it is NOT necessary for ballot pool members to submit more than one set of comments. The drafting team requests that all stakeholders (ballot pool members as well as other stakeholders) submit all comments through the electronic comment form.

### Next Steps

Successive ballots of FAC-003-X and FAC-003-3 will begin on Friday, March 30, 2012 and will end at 8 p.m. Eastern on Monday, April 9, 2012.

### Background

A Level 1 Appeal of FAC-003-3/FAC-003-X was received and reviewed by the Vice President of Standards and Training and then the Standards Committee's Executive Committee. They determined the appellant's claim to be valid in part, and determined that the modifications the SDT made to the applicability of FAC-003-3 and FAC-003-X prior to the recirculation ballot were substantive.

Consequently, the results of the recirculation ballots for FAC-003-3 and FAC-003-x have been declared void. The Standards Committee's Executive Committee remanded FAC-003-3 and FAC-003-x to the SDT with direction to consider the issues raised in the Exelon appeal and either:

- Modify the language added following the initial ballot and then post the standard for a successive ballot, or
- Remove the language added following the initial ballot and go directly to recirculation ballot.

A copy of the Executive Committee meeting minutes has been posted on the [project page](#) for information.

The SDT reviewed FAC-003-X and FAC-003-3 again and modified them slightly. More detail is available in the background section of the posted Unofficial Comment form, as well as in the updated [Considerations of Comments](#) report.

The purpose of Project 2010-07 is to ensure that all generator-owned Facilities are appropriately covered under NERC's Reliability Standards. While many Generator Owners and Generator Operators operate Facilities, commonly known as generator interconnection Facilities, that are considered by some entities to be transmission, these are most often radial Facilities that are not part of the integrated grid. As such, they should not be subject to the same standards applicable to Transmission Owners and Transmission Operators who own and operate Transmission Elements and Facilities that are part of the integrated grid.

As part of the BES, generators affect the overall reliability of the BES. But registering a Generator Owner or Generator Operator as a Transmission Owner or Transmission Operator, as has been the solution in some cases in the past, may decrease reliability by diverting the Generator Owner's or Generator Operator's resources from the operation of the equipment that actually produces electricity – the generation equipment itself.

The drafting team's goal is to ensure that an adequate level of reliability is maintained in the BES by clearly describing which standards need to be applied to generator interconnection Facilities that are not already applicable to Generator Owners or Generator Operators. The SDT believes that properly applying FAC-003 to Generator Owners as proposed in the redline standards posted for comment supports this objective.

Before reviewing the standards, the drafting team encourages all stakeholders to read the technical justification resource document it has provided to describe its rationale and its work thus far.

Additional information is available on the [project page](#).

### Standards Development Process

The [Standard Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. For more information or assistance, please contact Monica Benson at [monica.benson@nerc.net](mailto:monica.benson@nerc.net).

*For more information or assistance, please contact Monica Benson,  
Standards Process Administrator, at [monica.benson@nerc.net](mailto:monica.benson@nerc.net) or at 404-446-2560.*

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3353 Peachtree Rd. NE  
Suite 600, North Tower  
Atlanta, GA 30326  
404-446-2560 | [www.nerc.com](http://www.nerc.com)

## Standards Announcement

### Project 2010-07 – Generator Requirements at the Transmission Interface

#### Successive Ballot Results

#### [Now Available](#)

Ballots of two Generator Requirements at the Transmission Interface standards concluded Monday, April 9, 2012:

- FAC-003-3 – Transmission Vegetation Management
- FAC-003-X – Transmission Vegetation Management Program

Voting statistics for each ballot are listed below, and the [Ballots Results](#) page provides a link to the detailed results.

Standard	Quorum	Approval
FAC-003-3 – Transmission Vegetation Management	Quorum: 80.37%	Approval: 85.18%
FAC-003-X – Transmission Vegetation Management Program	Quorum: 80.10%	Approval: 85.01%

#### Next Steps

The drafting team will consider all comments received during the formal comment period and successive ballot. If the comments received during this formal comment period and ballot do not indicate the need for significant changes, the drafting team will post its consideration of those comments along with the standard and a recirculation ballot will be conducted.

#### Background

A Level 1 Appeal of FAC-003-3/FAC-003-X was received and reviewed by the Vice President of Standards and Training and then the Standards Committee's Executive Committee. They determined the appellant's claim to be valid in part, and determined that the modifications the SDT made to the applicability of FAC-003-3 and FAC-003-X prior to the recirculation ballot were substantive.

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- Remove the language added following the initial ballot and go directly to recirculation ballot.

A copy of the Executive Committee meeting minutes has been posted on the [project page](#) for information.

The purpose of Project 2010-07 is to ensure that all generator-owned Facilities are appropriately covered under NERC's Reliability Standards. While many Generator Owners and Generator Operators operate Facilities, commonly known as generator interconnection Facilities, that are considered by some entities to be transmission, these are most often radial Facilities that are not part of the integrated grid. As such, they should not be subject to the same standards applicable to Transmission Owners and Transmission Operators who own and operate Transmission Elements and Facilities that are part of the integrated grid.

As part of the BES, generators affect the overall reliability of the BES. But registering a Generator Owner or Generator Operator as a Transmission Owner or Transmission Operator, as has been the solution in some cases in the past, may decrease reliability by diverting the Generator Owner's or Generator Operator's resources from the operation of the equipment that actually produces electricity – the generation equipment itself.

The drafting team's goal is to ensure that an adequate level of reliability is maintained in the BES by clearly describing which standards need to be applied to generator interconnection Facilities that are not already applicable to Generator Owners or Generator Operators. The SDT believes that properly applying FAC-003 to Generator Owners as proposed in the redline standards posted for comment supports this objective.

Before reviewing the standards, the drafting team encourages all stakeholders to read the technical justification resource document it has provided to describe its rationale and its work thus far.

Additional information is available on the [project page](#).

### **Standards Development Process**

The [Standard Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. For more information or assistance, please contact Monica Benson at [monica.benson@nerc.net](mailto:monica.benson@nerc.net).

User Name

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Register

- Ballot Pools
- Current Ballots
- Ballot Results
- Registered Ballot Body
- Proxy Voters

Home Page

Ballot Results	
<b>Ballot Name:</b>	Project 2010-07 FAC-003-x Successive Ballot March 2012_in
<b>Ballot Period:</b>	3/30/2012 - 4/9/2012
<b>Ballot Type:</b>	Initial
<b>Total # Votes:</b>	306
<b>Total Ballot Pool:</b>	382
<b>Quorum:</b>	<b>80.10 % The Quorum has been reached</b>
<b>Weighted Segment Vote:</b>	85.01 %
<b>Ballot Results:</b>	<b>The drafting team is considering comments.</b>

Summary of Ballot Results									
Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain # Votes	No Vote	
			# Votes	Fraction	# Votes	Fraction			
1 - Segment 1.	95	1	55	0.887	7	0.113	13	20	
2 - Segment 2.	9	0.8	8	0.8	0	0	0	1	
3 - Segment 3.	80	1	44	0.8	11	0.2	13	12	
4 - Segment 4.	31	1	19	0.864	3	0.136	5	4	
5 - Segment 5.	94	1	52	0.839	10	0.161	9	23	
6 - Segment 6.	51	1	31	0.861	5	0.139	8	7	
7 - Segment 7.	1	0	0	0	0	0	0	1	
8 - Segment 8.	7	0.4	3	0.3	1	0.1	1	2	
9 - Segment 9.	5	0.1	1	0.1	0	0	0	4	
10 - Segment 10.	9	0.7	5	0.5	2	0.2	0	2	
<b>Totals</b>	<b>382</b>	<b>7</b>	<b>218</b>	<b>5.951</b>	<b>39</b>	<b>1.049</b>	<b>49</b>	<b>76</b>	

Individual Ballot Pool Results				
Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	<a href="#">View</a>
1	American Electric Power	Paul B. Johnson	Affirmative	<a href="#">View</a>
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman		
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	

1	Beaches Energy Services	Joseph S Stonecipher	Affirmative	<a href="#">View</a>
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Abstain	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	George S. Carruba		
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Abstain	
1	Georgia Transmission Corporation	Harold Taylor	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt	Affirmative	<a href="#">View</a>
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	<a href="#">View</a>
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Negative	<a href="#">View</a>
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney	Abstain	
1	Northeast Utilities	David Boguslawski		
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Matthey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	PECO Energy	Ronald Schloendorn	Negative	<a href="#">View</a>
1	Platte River Power Authority	John C. Collins		
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Brett A Koelsch		
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Duncel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	



1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	Santee Cooper	Terry L Blackwell	Abstain	
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Sierra Pacific Power Co.	Rich Salgo		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	<a href="#">View</a>
1	Southern Illinois Power Coop.	William Hutchison	Abstain	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Vermont Electric Power Company, Inc.	Kim Moulton		
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	<a href="#">View</a>
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	<a href="#">View</a>
3	Alabama Power Company	Richard J. Mandes	Negative	<a href="#">View</a>
3	Ameren Services	Mark Peters	Negative	
3	Anaheim Public Utilities Dept.	Kelly Nguyen		
3	APS	Steven Norris	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	<a href="#">View</a>
3	City of Alexandria	Michael Marcotte	Negative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	<a href="#">View</a>
3	City of Clewiston	Lynne Mila	Affirmative	<a href="#">View</a>
3	City of Green Cove Springs	Gregg R Griffin	Abstain	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Roseville	Susan E Gill-Zobitz		
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Negative	<a href="#">View</a>
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy	Richard Blumenstock	Abstain	
3	Cowlitz County PUD	Russell A Noble	Negative	<a href="#">View</a>
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Energy Delivery	Stephan Kern	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	<a href="#">View</a>
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Negative	<a href="#">View</a>
3	Georgia Systems Operations Corporation	William N. Phinney	Affirmative	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Sam Kokkinen		
3	Gulf Power Company	Paul C Caldwell	Negative	<a href="#">View</a>



3	Harney Electric Cooperative, Inc.	Shane Sweet	<a href="#">Abstain</a>	
3	Holland Board of Public Works	William Bush	<a href="#">Affirmative</a>	
3	Hydro One Networks, Inc.	David Kiguel	<a href="#">Affirmative</a>	
3	Imperial Irrigation District	Jesus S. Alcaraz	<a href="#">Affirmative</a>	
3	JEA	Garry Baker	<a href="#">Affirmative</a>	
3	Kansas City Power & Light Co.	Charles Locke	<a href="#">Affirmative</a>	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik	<a href="#">Abstain</a>	
3	Louisville Gas and Electric Co.	Charles A. Freibert	<a href="#">Affirmative</a>	
3	Manitoba Hydro	Greg C. Parent	<a href="#">Negative</a>	<a href="#">View</a>
3	Mississippi Power	Jeff Franklin	<a href="#">Negative</a>	<a href="#">View</a>
3	Municipal Electric Authority of Georgia	Steven M. Jackson	<a href="#">Affirmative</a>	
3	Muscatine Power & Water	John S Bos	<a href="#">Affirmative</a>	<a href="#">View</a>
3	Nebraska Public Power District	Tony Eddleman	<a href="#">Affirmative</a>	<a href="#">View</a>
3	New York Power Authority	Marilyn Brown	<a href="#">Affirmative</a>	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	<a href="#">Affirmative</a>	
3	Northern Indiana Public Service Co.	William SeDoris	<a href="#">Affirmative</a>	
3	NRG Energy Power Marketing, Inc.	Rick Keetch	<a href="#">Abstain</a>	
3	Ocala Electric Utility	David Anderson		
3	Orange and Rockland Utilities, Inc.	David Burke	<a href="#">Abstain</a>	
3	Oregon Trail Electric Cooperative	ned ratterman		
3	Orlando Utilities Commission	Ballard K Mutters	<a href="#">Affirmative</a>	
3	Owensboro Municipal Utilities	Thomas T Lyons	<a href="#">Affirmative</a>	
3	Pacific Gas and Electric Company	John H Hagen	<a href="#">Affirmative</a>	
3	PacifiCorp	Dan Zollner	<a href="#">Affirmative</a>	
3	Platte River Power Authority	Terry L Baker	<a href="#">Affirmative</a>	
3	PNM Resources	Michael Mertz	<a href="#">Affirmative</a>	
3	Potomac Electric Power Co.	Robert Reuter	<a href="#">Abstain</a>	
3	Progress Energy Carolinas	Sam Waters	<a href="#">Affirmative</a>	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	<a href="#">Affirmative</a>	
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	<a href="#">Affirmative</a>	
3	Sacramento Municipal Utility District	James Leigh-Kendall	<a href="#">Affirmative</a>	
3	Salt River Project	John T. Underhill	<a href="#">Affirmative</a>	
3	Santee Cooper	James M Poston	<a href="#">Abstain</a>	
3	Seattle City Light	Dana Wheelock	<a href="#">Affirmative</a>	
3	Seminole Electric Cooperative, Inc.	James R Frauen	<a href="#">Affirmative</a>	
3	Snohomish County PUD No. 1	Mark Oens	<a href="#">Affirmative</a>	
3	South Carolina Electric & Gas Co.	Hubert C Young	<a href="#">Abstain</a>	
3	Tacoma Public Utilities	Travis Metcalfe	<a href="#">Affirmative</a>	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	<a href="#">Affirmative</a>	
3	Tri-State G & T Association, Inc.	Janelle Marriott	<a href="#">Affirmative</a>	
3	Westar Energy	Bo Jones	<a href="#">Affirmative</a>	
3	Wisconsin Electric Power Marketing	James R Keller	<a href="#">Negative</a>	<a href="#">View</a>
3	Xcel Energy, Inc.	Michael Ibold	<a href="#">Negative</a>	<a href="#">View</a>
4	Alabama Municipal Electric Authority	Raymond Phillips	<a href="#">Affirmative</a>	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	<a href="#">Affirmative</a>	
4	American Municipal Power	Kevin Koloini	<a href="#">Affirmative</a>	
4	Blue Ridge Power Agency	Duane S Dahlquist	<a href="#">Affirmative</a>	
4	City of Clewiston	Kevin McCarthy	<a href="#">Affirmative</a>	<a href="#">View</a>
4	City of Redding	Nicholas Zettel	<a href="#">Affirmative</a>	
4	City Utilities of Springfield, Missouri	John Allen	<a href="#">Affirmative</a>	
4	Consumers Energy	David Frank Ronk	<a href="#">Abstain</a>	
4	Cowlitz County PUD	Rick Syring	<a href="#">Negative</a>	<a href="#">View</a>
4	Detroit Edison Company	Daniel Herring		
4	Flathead Electric Cooperative	Russ Schneider	<a href="#">Negative</a>	
4	Florida Municipal Power Agency	Frank Gaffney	<a href="#">Affirmative</a>	<a href="#">View</a>
4	Fort Pierce Utilities Authority	Thomas Richards		
4	Georgia System Operations Corporation	Guy Andrews	<a href="#">Abstain</a>	
4	Imperial Irrigation District	Diana U Torres	<a href="#">Affirmative</a>	
4	Indiana Municipal Power Agency	Jack Alvey	<a href="#">Affirmative</a>	<a href="#">View</a>
4	Integrus Energy Group, Inc.	Christopher Plante	<a href="#">Abstain</a>	
4	Madison Gas and Electric Co.	Joseph DePoorter	<a href="#">Abstain</a>	
4	Modesto Irrigation District	Spencer Tacke		
4	North Carolina Electric Membership Corp.	Bob Beadle	<a href="#">Affirmative</a>	
4	Northern California Power Agency	Tracy R Bibb	<a href="#">Affirmative</a>	

4	Ohio Edison Company	Douglas Hohlbaugh	<a href="#">Abstain</a>	
4	Old Dominion Electric Coop.	Mark Ringhausen	<a href="#">Affirmative</a>	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	<a href="#">Affirmative</a>	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	<a href="#">Affirmative</a>	
4	Sacramento Municipal Utility District	Mike Ramirez	<a href="#">Affirmative</a>	
4	Seattle City Light	Hao Li	<a href="#">Affirmative</a>	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	<a href="#">Affirmative</a>	
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	<a href="#">Affirmative</a>	
4	Wisconsin Energy Corp.	Anthony Jankowski	<a href="#">Negative</a>	<a href="#">View</a>
5	AEP Service Corp.	Brock Ondayko		
5	AES Corporation	Leo Bernier	<a href="#">Affirmative</a>	
5	Amerenue	Sam Dwyer	<a href="#">Negative</a>	
5	American Wind Energy Association	Natalie McIntire	<a href="#">Affirmative</a>	<a href="#">View</a>
5	Arizona Public Service Co.	Edward Cambridge	<a href="#">Affirmative</a>	
5	Avista Corp.	Edward F. Groce	<a href="#">Affirmative</a>	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar		
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	<a href="#">Affirmative</a>	
5	Bonneville Power Administration	Francis J. Halpin	<a href="#">Affirmative</a>	
5	BP Wind Energy North America Inc	Carla Bayer	<a href="#">Affirmative</a>	
5	BrightSource Energy, Inc.	Chifong Thomas	<a href="#">Affirmative</a>	<a href="#">View</a>
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	<a href="#">Affirmative</a>	
5	City of Redding	Paul Cummings	<a href="#">Affirmative</a>	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick		
5	City of Tallahassee	Brian Horton		
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy, Inc.	Mike D Hirst	<a href="#">Affirmative</a>	
5	Colorado Springs Utilities	Jennifer Eckels	<a href="#">Affirmative</a>	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	<a href="#">Abstain</a>	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	<a href="#">Abstain</a>	
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex	<a href="#">Negative</a>	<a href="#">View</a>
5	CPS Energy	Robert Stevens		
5	Detroit Edison Company	Christy Wicke	<a href="#">Affirmative</a>	
5	Dominion Resources, Inc.	Mike Garton	<a href="#">Affirmative</a>	
5	Duke Energy	Dale Q Goodwine	<a href="#">Affirmative</a>	
5	Dynegy Inc.	Dan Roethemeyer	<a href="#">Negative</a>	<a href="#">View</a>
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	<a href="#">Abstain</a>	
5	East Kentucky Power Coop.	Stephen Ricker		
5	Electric Power Supply Association	John R Cashin	<a href="#">Affirmative</a>	
5	Energy Northwest - Columbia Generating Station	James Saucedo		
5	Entegra Power Group, LLC	Kenneth B Parker	<a href="#">Abstain</a>	
5	Exelon Nuclear	Michael Korchynsky	<a href="#">Negative</a>	<a href="#">View</a>
5	ExxonMobil Research and Engineering	Martin Kaufman	<a href="#">Negative</a>	
5	FirstEnergy Solutions	Kenneth Dresner	<a href="#">Abstain</a>	
5	Florida Municipal Power Agency	David Schumann	<a href="#">Affirmative</a>	<a href="#">View</a>
5	Great River Energy	Preston L Walsh	<a href="#">Affirmative</a>	<a href="#">View</a>
5	Green Country Energy	Greg Froehling		
5	Imperial Irrigation District	Marcela Y Caballero	<a href="#">Affirmative</a>	
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	Infigen Energy US	Pamela C Zdenek		
5	Invenergy LLC	Alan Beckham	<a href="#">Affirmative</a>	
5	JEA	John J Babik	<a href="#">Affirmative</a>	
5	Kissimmee Utility Authority	Mike Blough	<a href="#">Affirmative</a>	
5	Lakeland Electric	James M Howard	<a href="#">Affirmative</a>	<a href="#">View</a>
5	Liberty Electric Power LLC	Daniel Duff	<a href="#">Negative</a>	
5	Lincoln Electric System	Dennis Florom	<a href="#">Abstain</a>	
5	Los Angeles Department of Water & Power	Kenneth Silver	<a href="#">Affirmative</a>	
5	Lower Colorado River Authority	Tom Foreman	<a href="#">Affirmative</a>	
5	Luminant Generation Company LLC	Mike Laney	<a href="#">Affirmative</a>	

5	Manitoba Hydro	S N Fernando	Negative	<a href="#">View</a>
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	<a href="#">View</a>
5	Nebraska Public Power District	Don Schmit	Affirmative	<a href="#">View</a>
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern California Power Agency	Hari Modi	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson		
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oklahoma Gas and Electric Co.	Kim Morphis		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	Colin Anderson	Abstain	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Gary L Tingley		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Fossil LLC	Mikhail Falkovich	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Abstain	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	RES Americas Inc	Ravi Bantu		
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	<a href="#">View</a>
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	<a href="#">View</a>
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	ACES Power Marketing	Jason L Marshall	Abstain	
6	AEP Marketing	Edward P. Cox	Affirmative	<a href="#">View</a>
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	RANDY A YOUNG	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirschak	Affirmative	
6	Colorado Springs Utilities	Lisa C Rosintoski		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Abstain	
6	Constellation Energy Commodities Group	Brenda L Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Negative	<a href="#">View</a>
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	<a href="#">View</a>
6	Florida Municipal Power Pool	Thomas Washburn	Abstain	
6	Florida Power & Light Co.	Silvia P. Mitchell	Negative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Luminant Energy	Brad Jones	Affirmative	

6	Manitoba Hydro	Daniel Prowse	Negative	<a href="#">View</a>
6	MidAmerican Energy Co.	Dennis Kimm	Affirmative	
6	New York Power Authority	William Palazzo		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	
6	South California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	<a href="#">View</a>
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		James A Maenner	Abstain	
8		Edward C Stein		
8		Roger C Zaklukiewicz	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini		
8	Utility Services, Inc.	Brian Evans-Mongeon	Negative	<a href="#">View</a>
8	Volkman Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William M Chamberlain		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Affirmative	
9	New York State Department of Public Service	Thomas Dvorsky		
9	Public Utilities Commission of Ohio	Klaus Lambeck		
10	Florida Reliability Coordinating Council	Linda Campbell		
10	Midwest Reliability Organization	James D Burley	Affirmative	<a href="#">View</a>
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Negative	<a href="#">View</a>
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	
10	Western Electricity Coordinating Council	Steven L. Rueckert		

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Ballot Results	
<b>Ballot Name:</b>	Project 2010-07 FAC-003-3 Successive Ballot March 2012_in
<b>Ballot Period:</b>	3/30/2012 - 4/9/2012
<b>Ballot Type:</b>	Initial
<b>Total # Votes:</b>	307
<b>Total Ballot Pool:</b>	382
<b>Quorum:</b>	<b>80.37 % The Quorum has been reached</b>
<b>Weighted Segment Vote:</b>	85.18 %
<b>Ballot Results:</b>	<b>The drafting team is considering comments.</b>

Summary of Ballot Results									
Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain	No Vote	
			# Votes	Fraction	# Votes	Fraction	# Votes		
1 - Segment 1.	95	1	55	0.873	8	0.127	12	20	
2 - Segment 2.	9	0.8	7	0.7	1	0.1	0	1	
3 - Segment 3.	80	1	45	0.804	11	0.196	12	12	
4 - Segment 4.	31	1	22	0.88	3	0.12	3	3	
5 - Segment 5.	94	1	53	0.841	10	0.159	8	23	
6 - Segment 6.	51	1	32	0.865	5	0.135	7	7	
7 - Segment 7.	1	0	0	0	0	0	0	1	
8 - Segment 8.	7	0.4	4	0.4	0	0	1	2	
9 - Segment 9.	5	0.1	1	0.1	0	0	0	4	
10 - Segment 10.	9	0.7	5	0.5	2	0.2	0	2	
<b>Totals</b>	<b>382</b>	<b>7</b>	<b>224</b>	<b>5.963</b>	<b>40</b>	<b>1.037</b>	<b>43</b>	<b>75</b>	

Individual Ballot Pool Results				
Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	<a href="#">View</a>
1	American Electric Power	Paul B. Johnson	Affirmative	<a href="#">View</a>
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman		
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Negative	<a href="#">View</a>

1	Beaches Energy Services	Joseph S Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Abstain	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	George S. Carruba		
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Abstain	
1	Georgia Transmission Corporation	Harold Taylor	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt	Affirmative	<a href="#">View</a>
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	<a href="#">View</a>
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Negative	<a href="#">View</a>
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney	Abstain	
1	Northeast Utilities	David Boguslawski		
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Matthey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	PECO Energy	Ronald Schloendorn	Negative	<a href="#">View</a>
1	Platte River Power Authority	John C. Collins		
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Brett A Koelsch		
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Duncel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	



1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	Santee Cooper	Terry L Blackwell	Abstain	
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Sierra Pacific Power Co.	Rich Salgo		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	<a href="#">View</a>
1	Southern Illinois Power Coop.	William Hutchison	Abstain	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Vermont Electric Power Company, Inc.	Kim Moulton		
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	<a href="#">View</a>
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	<a href="#">View</a>
3	Alabama Power Company	Richard J. Mandes	Negative	<a href="#">View</a>
3	Ameren Services	Mark Peters	Negative	
3	Anaheim Public Utilities Dept.	Kelly Nguyen		
3	APS	Steven Norris	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	<a href="#">View</a>
3	City of Alexandria	Michael Marcotte	Negative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	<a href="#">View</a>
3	City of Green Cove Springs	Gregg R Griffin	Abstain	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Roseville	Susan E Gill-Zobitz		
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Negative	<a href="#">View</a>
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy	Richard Blumenstock	Abstain	
3	Cowlitz County PUD	Russell A Noble	Negative	<a href="#">View</a>
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	<a href="#">View</a>
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Negative	<a href="#">View</a>
3	Georgia Systems Operations Corporation	William N. Phinney	Affirmative	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Sam Kokkinen		
3	Gulf Power Company	Paul C Caldwell	Negative	<a href="#">View</a>



3	Harney Electric Cooperative, Inc.	Shane Sweet	<a href="#">Abstain</a>	
3	Holland Board of Public Works	William Bush	<a href="#">Affirmative</a>	
3	Hydro One Networks, Inc.	David Kiguel	<a href="#">Affirmative</a>	
3	Imperial Irrigation District	Jesus S. Alcaraz	<a href="#">Affirmative</a>	
3	JEA	Garry Baker	<a href="#">Affirmative</a>	
3	Kansas City Power & Light Co.	Charles Locke	<a href="#">Affirmative</a>	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik	<a href="#">Abstain</a>	
3	Louisville Gas and Electric Co.	Charles A. Freibert	<a href="#">Affirmative</a>	
3	Manitoba Hydro	Greg C. Parent	<a href="#">Negative</a>	<a href="#">View</a>
3	Mississippi Power	Jeff Franklin	<a href="#">Negative</a>	<a href="#">View</a>
3	Municipal Electric Authority of Georgia	Steven M. Jackson	<a href="#">Affirmative</a>	
3	Muscatine Power & Water	John S Bos	<a href="#">Affirmative</a>	<a href="#">View</a>
3	Nebraska Public Power District	Tony Eddleman	<a href="#">Affirmative</a>	<a href="#">View</a>
3	New York Power Authority	Marilyn Brown	<a href="#">Affirmative</a>	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	<a href="#">Affirmative</a>	
3	Northern Indiana Public Service Co.	William SeDoris	<a href="#">Affirmative</a>	
3	NRG Energy Power Marketing, Inc.	Rick Keetch	<a href="#">Abstain</a>	
3	Ocala Electric Utility	David Anderson		
3	Orange and Rockland Utilities, Inc.	David Burke	<a href="#">Abstain</a>	
3	Oregon Trail Electric Cooperative	ned ratterman		
3	Orlando Utilities Commission	Ballard K Mutters	<a href="#">Affirmative</a>	
3	Owensboro Municipal Utilities	Thomas T Lyons	<a href="#">Affirmative</a>	
3	Pacific Gas and Electric Company	John H Hagen	<a href="#">Affirmative</a>	<a href="#">View</a>
3	PacifiCorp	Dan Zollner	<a href="#">Affirmative</a>	
3	Platte River Power Authority	Terry L Baker	<a href="#">Affirmative</a>	
3	PNM Resources	Michael Mertz	<a href="#">Affirmative</a>	
3	Potomac Electric Power Co.	Robert Reuter	<a href="#">Abstain</a>	
3	Progress Energy Carolinas	Sam Waters	<a href="#">Affirmative</a>	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	<a href="#">Affirmative</a>	
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	<a href="#">Affirmative</a>	
3	Sacramento Municipal Utility District	James Leigh-Kendall	<a href="#">Affirmative</a>	
3	Salt River Project	John T. Underhill	<a href="#">Affirmative</a>	
3	Santee Cooper	James M Poston	<a href="#">Abstain</a>	
3	Seattle City Light	Dana Wheelock	<a href="#">Affirmative</a>	
3	Seminole Electric Cooperative, Inc.	James R Frauen	<a href="#">Affirmative</a>	
3	Snohomish County PUD No. 1	Mark Oens	<a href="#">Affirmative</a>	
3	South Carolina Electric & Gas Co.	Hubert C Young	<a href="#">Abstain</a>	
3	Tacoma Public Utilities	Travis Metcalfe	<a href="#">Affirmative</a>	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	<a href="#">Affirmative</a>	
3	Tri-State G & T Association, Inc.	Janelle Marriott	<a href="#">Affirmative</a>	
3	Westar Energy	Bo Jones	<a href="#">Affirmative</a>	
3	Wisconsin Electric Power Marketing	James R Keller	<a href="#">Negative</a>	<a href="#">View</a>
3	Xcel Energy, Inc.	Michael Ibold	<a href="#">Negative</a>	<a href="#">View</a>
4	Alabama Municipal Electric Authority	Raymond Phillips	<a href="#">Affirmative</a>	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	<a href="#">Affirmative</a>	
4	American Municipal Power	Kevin Koloini	<a href="#">Affirmative</a>	
4	Blue Ridge Power Agency	Duane S Dahlquist	<a href="#">Affirmative</a>	
4	City of Clewiston	Kevin McCarthy	<a href="#">Affirmative</a>	<a href="#">View</a>
4	City of Redding	Nicholas Zettel	<a href="#">Affirmative</a>	
4	City Utilities of Springfield, Missouri	John Allen	<a href="#">Affirmative</a>	
4	Consumers Energy	David Frank Ronk	<a href="#">Abstain</a>	
4	Cowlitz County PUD	Rick Syring	<a href="#">Negative</a>	<a href="#">View</a>
4	Detroit Edison Company	Daniel Herring		
4	Flathead Electric Cooperative	Russ Schneider	<a href="#">Negative</a>	
4	Florida Municipal Power Agency	Frank Gaffney	<a href="#">Affirmative</a>	<a href="#">View</a>
4	Fort Pierce Utilities Authority	Thomas Richards		
4	Georgia System Operations Corporation	Guy Andrews	<a href="#">Abstain</a>	
4	Imperial Irrigation District	Diana U Torres	<a href="#">Affirmative</a>	
4	Indiana Municipal Power Agency	Jack Alvey	<a href="#">Affirmative</a>	
4	Integrus Energy Group, Inc.	Christopher Plante	<a href="#">Abstain</a>	
4	Madison Gas and Electric Co.	Joseph DePoorter	<a href="#">Affirmative</a>	
4	Modesto Irrigation District	Spencer Tacke	<a href="#">Affirmative</a>	
4	North Carolina Electric Membership Corp.	Bob Beadle	<a href="#">Affirmative</a>	
4	Northern California Power Agency	Tracy R Bibb	<a href="#">Affirmative</a>	

4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	<a href="#">View</a>
5	AEP Service Corp.	Brock Ondayko		
5	AES Corporation	Leo Bernier	Affirmative	
5	Amerenue	Sam Dwyer	Negative	
5	American Wind Energy Association	Natalie McIntire	Affirmative	<a href="#">View</a>
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar		
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Bayer	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	<a href="#">View</a>
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick		
5	City of Tallahassee	Brian Horton		
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy, Inc.	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Abstain	
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex	Negative	<a href="#">View</a>
5	CPS Energy	Robert Stevens		
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Negative	<a href="#">View</a>
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	East Kentucky Power Coop.	Stephen Ricker		
5	Electric Power Supply Association	John R Cashin	Affirmative	
5	Energy Northwest - Columbia Generating Station	James Saucedo		
5	Entegra Power Group, LLC	Kenneth B Parker	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Negative	<a href="#">View</a>
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	<a href="#">View</a>
5	Great River Energy	Preston L Walsh	Affirmative	<a href="#">View</a>
5	Green Country Energy	Greg Froehling		
5	Imperial Irrigation District	Marcela Y Caballero	Affirmative	
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	Infigen Energy US	Pamela C Zdenek		
5	Invenergy LLC	Alan Beckham	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	<a href="#">View</a>
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	

5	Manitoba Hydro	S N Fernando	Negative	<a href="#">View</a>
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	<a href="#">View</a>
5	Nebraska Public Power District	Don Schmit	Affirmative	<a href="#">View</a>
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern California Power Agency	Hari Modi	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson		
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oklahoma Gas and Electric Co.	Kim Morphis		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	Colin Anderson	Abstain	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Gary L Tingley		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Fossil LLC	Mikhail Falkovich	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Abstain	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	RES Americas Inc	Ravi Bantu		
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	<a href="#">View</a>
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	<a href="#">View</a>
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	ACES Power Marketing	Jason L Marshall	Abstain	
6	AEP Marketing	Edward P. Cox	Affirmative	<a href="#">View</a>
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	RANDY A YOUNG	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirschak	Affirmative	
6	Colorado Springs Utilities	Lisa C Rosintoski		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Abstain	
6	Constellation Energy Commodities Group	Brenda L Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Negative	<a href="#">View</a>
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	<a href="#">View</a>
6	Florida Municipal Power Pool	Thomas Washburn	Abstain	
6	Florida Power & Light Co.	Silvia P. Mitchell	Negative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Luminant Energy	Brad Jones	Affirmative	

6	Manitoba Hydro	Daniel Prowse	Negative	<a href="#">View</a>
6	MidAmerican Energy Co.	Dennis Kimm	Affirmative	
6	New York Power Authority	William Palazzo		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	
6	South California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	<a href="#">View</a>
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein		
8		James A Maenner	Abstain	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini		
8	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
8	Volkman Consulting, Inc.	Terry Volkman	Affirmative	
9	California Energy Commission	William M Chamberlain		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Affirmative	
9	New York State Department of Public Service	Thomas Dvorsky		
9	Public Utilities Commission of Ohio	Klaus Lambeck		
10	Florida Reliability Coordinating Council	Linda Campbell		
10	Midwest Reliability Organization	James D Burley	Affirmative	<a href="#">View</a>
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Negative	<a href="#">View</a>
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	
10	Western Electricity Coordinating Council	Steven L. Rueckert		

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 Washington Office: 1120 G Street, N.W. : Suite 990 : Washington, DC 20005-3801

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**Individual or group. (23 Responses)**  
**Name (16 Responses)**  
**Organization (16 Responses)**  
**Group Name (7 Responses)**  
**Lead Contact (7 Responses)**  
**Question 1 (22 Responses)**  
**Question 1 Comments (23 Responses)**

Individual
Brenda Frazer
Edison Mission Marketing & Trading
Yes
Individual
John Bee
Exelon
No
<p>Exelon disagrees with the current proposed draft of FAC-003-3/X because the reference to a “clear line of sight from the generating station switchyard fence to the point of interconnection” does not clarify the Standard and is unsupported by any technical basis. Furthermore, the definition of “clear line of sight” added by the SDT does not address or remedy the substantive concerns raised in Exelon’s appeal. Exelon reiterates that the SDT should base the applicability of the Standard on the length of the transmission line, a measurable component of the bulk electric system, and remove all references to a “clear line of sight.” This approach is consistent with previous draft versions of FAC-003 proposed by the SDT and the Ad Hoc Group and the recent recommendation of the NERC Vice President of Standards and Training in response to Exelon’s appeal. Alternatively, if the “clear line of sight” verbiage remains, the Standards should be clarified to remove the requirement that the line of sight be established from “the generating station switchyard fence to the point of interconnection” and to add a requirement or clarify that “clear line of sight” for lines of one mile or less can include observation of the length of the transmission lines from various vantage points within the owner controlled property. The SDT states in the “Background” section of the Unofficial Comment Form that “a reference to the line of sight is clarifying and makes explicit the SDT’s implicit intent from day one.” Yet, the SDT offers no support for its “implicit intent from day one,” and a review of the history for these Standards certainly does not support an “implicit intent from day one” to require a clear line of sight from a fixed location, let alone the generating station switchyard fence, to the point of interconnection. The Technical Justification document posted in September 2011 (p. 3) refers to the Ad Hoc Group’s original thought to exclude from the Standards any transmission lines that were “less than two spans [long] (generally one half mile from the generator property line).” In agreeing “with that intended exclusion in principle,” the SDT explained (p. 3) that, “[a]fter reviewing formal comments, the SDT agreed to revise the exclusion so that it applies to a Facility [transmission line] if its length is ‘one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard’ to approximate line of sign [sic] from a fixed point,” (the fixed point being the fenced area of the generating station switchyard). From the start, the Ad Hoc Group and SDT focused on the length of the transmission line (either a half mile as proposed by the Ad Hoc Group or a mile as proposed by the SDT) as the proxy for line of sight, the presumption being that up to a certain distance, the overhead line is in the line of sight at various locations throughout the Generator Owner’s property and reasonably subject to being managed through normal day-to-day plant activities. The SDT has not, until the most recent iteration of the Standards, focused on requiring a “clear line of sight from the generating station switchyard fence to the point of interconnection.” As support for adding the “clear line of sight” requirement to the FAC-003-3/X Standards in December 2011, the SDT noted as follows: “We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor.” With the addition of an explicit line of sight reference here, the SDT believes it has clarified its original intent. (Side bar comments to FAC-003-3, Section 4.3.1 (December 1, 2011): FAC-003-X, Section</p>

4.3.1 (December 1, 2011)). This explanation does nothing more than (1) reiterate the point the SDT has maintained throughout the entire drafting process, namely that "the one mile length" of a transmission line "is a reasonable approximation of line of sight," and (2) explain that the SDT included a "fixed starting point" (the fenced area of the generation station switchyard) from which to measure the length of the transmission line to address stakeholder concerns about excessive Generator Owner discretion with respect to the location from which to take a measurement and inconsistent application of the Standards. Again, the SDT's "intent" (implicit or otherwise) "from day one" has nothing to do with establishing a "clear line of sight from the generating switchyard fence to the point of interconnection." In addition, requiring a "clear line of sight from the generating station switchyard fence to the point of interconnection" is technically unsupported. The SDT just added the requirement for a "clear line of sight to the point of interconnection" language without considering the implications of why such a change was required or reasonable. While a specific fixed starting point (the generating station switchyard fence) and end point (the point of interconnection) may make sense for establishing a starting and ending point from which to measure the length of the transmission line (the one-mile limitation), it does not make sense when considering a clear line of sight, especially in light of stakeholder comments and the SDT's repeated acknowledgment that in many cases, generation Facilities are either (1) staffed and the overhead portion is within the line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach. (Consideration of Comments, Generator Requirements at the Transmission Interface, Project 2010-07 (for November 9, 2011 successive ballot), p. 1; Technical Justification Resource Document (posted March 2012), p. 3.) By inserting the "clear line of sight" requirement now without modifying the fixed starting point, the SDT completely ignores its unequivocal acknowledgment that generation Facilities are unique in the sense that personnel can see the line from various locations within the owner controlled area and many generation Facilities are over paved surfaces. The absence of a technical justification for imposing a "clear line of sight" is illustrated by the following example. A Generator Owner transmission line leaving the generating station could take a "dog leg" turn (the line turns at one of the towers). Standing at the tower in this example, an individual would have a clear line of sight of the entire line to either end of the short-distance line (to the end leaving the station and to the end terminating at the point of interconnection). Since the generating Facility is within the Generator Owner's property line or controlled area and consistently staffed by personnel who patrol the owner controlled area, the line can be observed and maintained by staff in the same manner as any other short distance line with a "clear" line of sight from the "generating station switchyard fence to the point of interconnection." Moreover, to the extent a portion or the entire length of the line travels over paved surfaces or structures, any barriers or obstacles to a clear line of sight will not be caused by vegetation, as discussed in FAC-003-3/X but, rather, by equipment, components, or structures. Clearance between generator lines and structures is already covered in other NERC Standards. For those lines that do travel over areas of vegetation, the regular personnel monitoring and surveillance of the areas over which the lines travel provides reasonable assurance of protection from vegetation related events. Rather than clarifying the Standards, the SDT has introduced more ambiguity into the Standards. The addition of the "generating station switchyard fence" as the point of reference for a clear line of sight adds more confusion than it solves by introducing a variable that will be left to the discretion of generator owner and an auditor. What is the definition of a "generating station switchyard fence?" As Exelon noted in its Appeal and at least one other Registered Entity noted in its Comments for the first successive ballot (Consideration of Comments posted March 2012, p. 38), some generation facilities do not have generating switchyards or generating switchyard fences. A requirement that there be a clear line of sight from the "generating switchyard fence" is meaningless in cases where no such switchyard or fence exists. Is it the fence surrounding the generating unit or is it meant to refer to the fence surrounding the Transmission Owner's associated switchyard and relay house? What if there are multiple physical fence lines between the generating unit and the point of interconnection? In addition, by introducing a point of reference that is not a physical component or measurable reference of the bulk electric system, what precludes the Generator Owner from arbitrarily moving the fence line to avoid applicability? Also lacking in clarity is the addition of a footnote defining "clear line of sight" to mean "the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day." Generation Owners will be left to determine what constitutes an "average person," a "clear day," and

"special instrumentation." For all these reasons, Exelon requests that the SDT base the applicability of the Standard on the length of the transmission line, a measurable component of the bulk electric system, and remove all references to a "clear line of sight." Alternatively, if the "clear line of sight" verbiage remains, the Standards should be clarified to remove the requirement that the line of sight be established from "the generating station switchyard fence to the point of interconnection" and to add a requirement or clarify that "clear line of sight" for lines of one mile or less can include observation of the length of the transmission lines from various vantage points within the owner controlled property.

Individual

Ray Phillips

Alabama Municipal Electric Authority

Yes

Group

Northeast Power Coordinating Council

Guy Zito

No

The Applicability language used in FAC-003-X is different from that used in FAC-003-3. The language used in FAC-003-X uses "and" in several places which leads to confusion and a probable "null" result, whereas the language in FAC-003-3 is more straightforward and makes use of "or". The FAC-003-3 applicability language should be used in FAC-003-X. The explanation of what is meant by line of sight should be incorporated in the Applicability Section wording as standards, at NERC's direction, are supposed to be getting away from the use of footnotes.

Individual

Joe Petaski

Manitoba Hydro

No

Manitoba Hydro does not support the changes being proposed in Project 2010-07. If a Generator Owner is required to register as a TO, all the Requirements applicable to a TO should apply. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. For additional information, please see Manitoba Hydro's comments submitted in the comment period ending November 18, 2011. Manitoba Hydro does not believe that the SDT fully addressed our concerns in their responses to our comments in that commenting period.

Individual

Dan Roethemeyer

Dynegy

No

Using the switchyard fence is too restrictive. There could be too many different layouts to keep it fair for all GO's. For example, there could be an obstruction if limited to standing at the existing switchyard fence but if one were to move a short distance away (i.e. corner of GO's building) then it could be possible to see both ends of the tie line. This would also meet the intent of the added language since it is now within line of sight. I recommend deleting "switchyard fence". Also, in order to account for a GO not being able to dictate what happens inside a TO's switchyard, I recommend adding "entry or" between "of" and "interconnection".

Individual

Thad Ness

American Electric Power

Yes

Individual

John Seelke

Public Service Enterprise Group



Yes
Individual
Dale Fredrickson
Wisconsin Electric
No
We strongly oppose the addition of the "clear" line of sight criteria to the Applicability. The report of the GOTO Task Force, as well as prior draft revisions to FAC-003, included a test based solely on circuit length, which is sufficient in our view to assure that the BES is not at risk due to vegetation issues on generator tie lines. The expansion to include short tie lines, including those entirely on the Generator Owner's property which may not meet the line of sight qualifier, has no benefit to reliability. Rather, the expanded applicability and the requirement for a formal vegetation management program in these cases will consume resources for compliance that are better used for actual reliability improvements.
Group
Texas Reliability Entity
Don Jones
No
In FAC-003-X: 1. We appreciate that you took Regional Entity out of the Applicability section, but there is still a Requirement (R4) that applies to the Regional Entity. Is that Requirement intended to be enforceable against the Regional Entities? We suggest removing Requirement R4. 2. In Part D.1.1, only the Regional Entity should be listed as Compliance Monitor, since the Regional Entity has been removed as an Applicable entity. 3. In the Purpose section, update the reference to NERC (use "Corporation" instead of "Council"), and capitalize "Rights-of-Way" since it is a defined term. 4. We suggest that you spell out "Regional Entity" in Applicability part 4.2.1. 5. In the implementation plan, the reference to "R3" should be corrected to "R1" in the following sentence: "In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption." In FAC-003-3: 6. There is no Compliance Monitor listed on page 17. At least the Regional Entity should be listed here. 7. In the Severe VSL for R2, replace "Transmission Owner" with "responsible entity." 8. In the Severe VSL for R1 and R2, remove "active transmission line" before "ROW." That phrase is confusing in the VSLs because it does not appear in the requirements, and it is not clear whether it is intended to change the requirements. 9. In Table 2 (Alternating Current – meters AND Direct Current) the footnote references are wrong. We think they should be 9 and 10, rather than 7 and 8. 10. In Table 2 (Direct Current), the column headings are wrong. Only the first column heading should refer to voltage. The rest should refer to MVCD.
Individual
bf
asdf
Individual
Daniel Duff
Liberty Electric Power LLC
No
The "line of sight" should be removed. It opens up the entity to a finding of non-compliance if a temporary blockage of line of sight should occur.
Individual
Martin Kaufman
ExxonMobil Research and Engineering
No
While it is clear that the SDT is attempting to include those facilities owned by Generator Owners that travel long distances down right-of-ways, the applicability section of FAC-003-X and FAC-003-3, as written, require industrial complexes with cogeneration facilities to develop Transmission Vegetation

Management Programs for generator lead lines that are not exposed to vegetation. Industrial cogeneration location is typically chosen based on the availability of fuel, need for steam, or availability of real estate. This can result with the generation facilities (including the GSU transformer substation) being located deep within the plant with long cable routes and multiple substation connections between the GSU transformer substation and utility interconnection facility located near the perimeter of the industrial complex's fence line. Additionally, the routes of these generator lead lines fundamentally differ in nature from a typical IPP's generator lead line route. Since they are located within the fence line of an industrial complex, the routes rarely contain vegetation; are frequently travelled by plant personnel; rarely run in straight lines (i.e. no single line of sight); and frequently terminate at a facility located at the fence line of the industrial complex where a transmission company takes ownership of the power lines that leave the industrial complex. Furthermore, the use of the term "generating station switchyard" may result in inconsistent enforcement of the Transmission Vegetation Management Program Reliability Standard as the use of the term implies there is only one substation located within a Generator Owner's complex. Typically, there are multiple substations that connect an industrial complex's generator lead-line to the utility interconnection facility located near the perimeter of the industrial complex's fence line. The two obvious interpretations for the "generating station switchyard" are the substation that is directly connected to the generator's GSU, and the utility interconnection facility. The concerns raised by NERC and FERC staff related generator owned transmission like assets originate with those conductors that leave the Generator Owner's complex's fence line and travel long distances down vacant right-of-ways, and, therefore, the applicability of those Reliability Standards that apply to transmission facilities should start with the fence line. Since the Bulk Electric System is contiguous, reliability concerns related to the facilities between the GSU transformer substation and utility interconnection facility are covered by those Reliability Standards that apply to Generator Owners and Generator Operators. In order to account for the different nature of industrial complex's generation facilities, the SDT should consider re-phrasing the applicability section of FAC-003-X and FAC-003-3 to start counting the length of a generator lead line at the fence line of the Generator Owner's complex and not the generating station switchyard.

Individual

Brian Murphy

NextEra Energy, Inc.

No

Under the line of sight approach, a generation lead would be exempt from the requirements of FAC-003-3 if personnel can see the generation lead corridor and the generation lead is less than a mile. The rationale provided to support of this proposal is that "Stakeholders have generally supported the rationale for exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit." However, there is no data that supports that generation leads of less than a mile are categorically not subject to vegetation contacts and outages. Further, in practice this approach will unduly discriminate against longer generator leads, many of which are associated with renewable energy resource, such as wind and solar. NextEra Energy Inc. (NextEra) believes a more technically sound approach is that all generator leads be subject to FAC-003-3, with the opportunity to be exempted from FAC-003-3 regulation upon an affirmative demonstration that no vegetation threat exists. To implement this approach, NextEra proposes that FAC-003-3 applicability 4.3.1 be revised to read as follows: "Overhead transmission lines, including generation leads, beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner and are: 4.3.1.1. Operated at 200kV or higher; or 4.3.1.2. Operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator; or 4.3.1.3. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC." NextEra would also propose to add a new section 4.3.2 that reads as follows: "If a Generator Owner or Transmission Owner can demonstrate that the entire Right-of-Way is paved or otherwise devoid of vegetation, and reasonably expected to remain so, the Generation Owner or Transmission Owner is exempt from FAC-003-3." In addition, NextEra proposes that the drafting team consider a megawatt (MW) threshold for a generating plant from both a stand-alone and aggregate bases. For example, it is unlikely that vegetation contact tripping a 50 megawatt generator (or a generator of 100 MWs in the aggregate) connected to a robust transmission system with a large amount of load and generation will adversely impact reliability. Thus, NextEra proposes the addition of a provision that exempts a generation lead for stand-alone generators of 50 MWs and below and generators in the aggregate of

100 MWs and below, unless there is an affirmative request for the generator to comply with FAC-003-3 by a Transmission Operator or Reliability Coordinator. Such a provision could read as follows: "Unless a Transmission Operator or Reliability Coordinator requests in writing that a stand-alone generator of 50 Megawatts (MWs) or below (with a 200 kV or above generation lead) or a generator in the aggregate of 100 MWs or below (with a 200 kV or above generation lead) comply with FAC-003-3, these classes of generators and their associated generation leads are exempt from complying with FAC-003-3. In the event a Transmission Operator or Reliability Coordinator requests in writing that a stand-alone generator of 50 Megawatts (MWs) or below (with a 200 kV or above generation lead) or a generator in the aggregate of 100 MWs or below (with a 200 kV or above generation lead) comply with FAC-003-3, the associated registered entity shall have one-year from the date of the written correspondence to come into compliance with FAC-003-3."
Group
Southwest Power Pool Standards Development Team
Jonathan Hayes
No
Clear line of sight" means the distance that can be seen by the average person "standing at ground level "without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.
Individual
Jean Nitz
ACES Power Marketing
Yes
Group
Bonneville Power Administration
Chris Higgins
Yes
BPA has no other comments or concerns at this time.
Group
Southern Company
Antonio Grayson
No
The requirement as worded implies or could be interpreted to mean one's line of site would have to originate at the generating station switchyard fence. The "clear line of site" should also include that from a roadway that travels in proximity to the line. Such a roadway's purpose would likely include access to the line for inspections, maintenance, travel from the plant to the transmission substation, etc. Since the terrain between the generating station switchyard fence and the point of interconnection could obscure the view from the fence, the clear line of site from such a roadway should be allowed. The requirement should be revised to read, "...or (2) does not have clear line of sight1 from the generating station switchyard fence or a roadway to the point of interconnection with a Transmission Owner's Facility."
Group
NERC Compliance Policy
Mike Garton
Yes
Dominion offers the following comments on the Implementation Plan for FAC-003-3: 1. The last paragraph on page 2 refers to FAC-003-3 Requirement 1.3. FAC-003-3 does not appear to contain a Requirement 1.3; therefore, Dominion recommends that the reference in the Implementation Plan be clarified. 2. The 3rd paragraph on page 3 refers to FAC-003-3 Requirement 1.2. FAC-003-3 does not appear to contain a Requirement 1.2; therefore, Dominion recommends that the reference in the Implementation Plan be clarified.
Individual
Patrick Brown

Essential Power, LLC
Yes
Group
MRO NSRF
WILL SMITH
Yes
The NSRF agrees with the clarifying changes related to adding the phrase “.....do not have a clear line of sight from the generating station switchyard fence to the point of interconnection with a Transmission Owner’s Facility.....”, however, have the following comment for SDT consideration: • The Evidence Retention in FAC-003-3, Part C, Compliance, and Section 1.2 implies that an entity is required to retain evidence for the time period since the last audit. Since Generator Owners’ audit cycles are six (6) years, and the following paragraph states that to show compliance for R1, R2, R3, R5, R6 and R7 is three calendar years unless directed by the CEA to retain longer as part of an investigation, this section should be clarified to require six years retention for applicable Generator Owners.
Individual
Russell A. Noble
Cowlitz County PUD
No
Cowlitz must agree with Exelon’s position inasmuch that the vantage point must be related to the generating station switchyard maintenance or the operation and maintenance of the generation plant itself, and afford a clear perspective of vegetation proximity. Cowlitz also agrees with the SDT’s line of sight clarifying verbiage. However, restricting the vantage point to the generating station switchyard fence does not encompass the spirit of the exclusion. A short one-mile transmission interconnection line – from the generating station switchyard to the interconnection point – that is frequently viewed during the operation and maintenance of the generation plant itself should be the crux of the exemption. The exact location, i.e., the generating station switchyard fence, of the vantage point is not the make or break of whether the interconnection line will be routinely inspected by default. As an example, consider a hydro project where the generating station switchyard may be located near the tailrace inside a canyon. From the fence line of this particular switchyard, only the interconnection line traversing up the canyon wall is visible. However, topside of the dam where maintenance and operational personnel must daily traverse under the interconnection line to access the powerhouse and switchyard may afford a clear view of both the generating station switchyard below and the interconnection station which includes the whole interconnecting line in-between. Further, if parts of the interconnecting line is viewable in two or even three vantage points beneath the interconnection line during the normal transit to and from the generating station switchyard, the sum of which comprises the whole line, can this not also meet the spirit of the exclusion? Conversely, Cowlitz does not hold that any vantage point should be acceptable. Any vantage point that must require special effort to access no matter the ease is not acceptable. Also, a perpendicular view of a line (not under or near) complicates perception of the proximity of vegetation to a line. Views parallel down the right-of-way maximizes perception of vegetation proximity. Further, a long line that is fully viewable during transit to and from the generation plant increases the chance of hidden vegetation encroachment. Cowlitz strongly opposes any trivializing of reliability compliance collateral damage. Forcing compliance activities with no reliability return must be avoided wherever possible. As a stakeholder with limited time to invest reviewing all the comments submitted, Cowlitz offers an apology to Exelon for missing their initial comment. Cowlitz commends Exelon’s persistence in this matter. * * * Suggested language: ...or (2) do not have a clear line of sight (leave the footnote in place) up and/or down from a single vantage point within the transmission right-of-way where both the origin at the generating station switchyard and the termination interconnection point with the Transmission Owner’s Facility can be seen, and where operations or maintenance personnel frequent on foot during normal generation plant or generating station switchyard access is made...
Individual
Michelle R. D’Antuono
Ingleside Cogeneration LP

Yes

# Consideration of Comments

## Generator Requirements at the Transmission Interface Project 2010-07 (FAC-003-3 and FAC-003-x)

The Generator Requirements at the Transmission Interface Drafting Team thanks all commenters who submitted comments on the second formal posting of FAC-003-3 and FAC-003-X, as part of Project 2010-07—Generator Requirements at the Transmission Interface. These standards were posted for a 30-day public comment period from March 9, 2012 through April 9, 2012. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 22 sets of comments, including comments from approximately 83 different people from approximately 76 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

The SDT considered all comments submitted and has proposed the following minor changes to FAC-003-X and FAC-003-3:

- **FAC-003-X:**
  - The Applicability section was reformatted to make it clear that the standard applies on a Facility by Facility basis (as in FAC-003-3), not simply to all generator interconnection Facilities owned by a Generator Owner with at least one qualifying generator interconnection Facility.
  - In the Purpose section, Right-of-Way was capitalized because it is an approved NERC glossary term and “North American Electric Reliability Council” was changed to “North American Electric Reliability Corporation.”
  - Regional Entity was added back to the Applicability section of the standard. Requirement R4 is assigned to the Regional Entity, and the Project 2010-07 does not have the authority, based on the scope outlined in its SAR, to modify that requirement. Thus, Regional Entity must remain in the Applicability section. In all cases, Regional Entity has been spelled out rather than referred to as “RE.”
  - New boilerplate language, recently approved by NERC legal staff, was added to the Effective Dates section of the standard and the Implementation Plan.
- **FAC-003-3:**
  - A typo was found in the Severe VSL for R2; the previous reference to “Transmission Owner” was changed to “responsible entity,” as in all other FAC-003-3 VSLs.
  - New boilerplate language, recently approved by NERC legal staff, was added to the Effective Dates section of the standard and the Implementation Plan.

Other minority comments are addressed alongside their specific comments below.

*Note that if both FAC-003-X and FAC-003-3 are approved in this recirculation ballot, only FAC-003-3 will be presented to NERC's Board of Trustees. FAC-003-X has been modified so that the generator interconnection Facility gap can be quickly addressed in the event that neither FAC-003-2 nor FAC-003-3 is approved by FERC.*

All comments submitted may be reviewed in their original format on the standard's project page:

[http://www.nerc.com/filez/standards/Project2010-07\\_GOTO\\_Project.html](http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html)

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President of Standards and Training, Herb Schrayshuen, at 404-446-2560 or at [herb.schrayshuen@nerc.net](mailto:herb.schrayshuen@nerc.net). In addition, there is a NERC Reliability Standards Appeals Process.<sup>1</sup>

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<sup>1</sup> The appeals process is in the Standard Processes Manual:  
[http://www.nerc.com/files/Appendix\\_3A\\_Standard\\_Processes\\_Manual\\_Rev%201\\_20110825.pdf](http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_Rev%201_20110825.pdf).

## Index to Questions, Comments, and Responses

1. The Project 2010-07 SDT considered Exelon’s appeal in the context of other stakeholder comments submitted in the first successive ballot between October 5 and November 18, 2011, along with advice from NERC staff. The SDT continues to believe that a reference to line of sight is clarifying and makes explicit the SDT’s implicit intent from day one. Thus, it kept the line of sight reference but made a few additional changes for formatting clarity and language consistency. The team also added a footnote to further explain what it means by “line of sight.” Do you agree with these changes? If not, please provide specific alternative language. .... 8



**The Industry Segments are:**

- 1 — Transmission Owners
- 2 — RTOs, ISOs
- 3 — Load-serving Entities
- 4 — Transmission-dependent Utilities
- 5 — Electric Generators
- 6 — Electricity Brokers, Aggregators, and Marketers
- 7 — Large Electricity End Users
- 8 — Small Electricity End Users
- 9 — Federal, State, Provincial Regulatory or other Government Entities
- 10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment											
				1	2	3	4	5	6	7	8	9	10		
1.	Group	Guy Zito	Northeast Power Coordinating Council												X
Additional Member		Additional Organization		Region		Segment Selection									
1.	Alan Adamson	New York State Reliability Council, LLC		NPCC	10										
2.	Greg Campoli	New York Independent System Operator		NPCC	2										
3.	Sylvain Clermont	Hydro-Quebec TransEnergie		NPCC	1										
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.		NPCC	1										
5.	Gerry Dunbar	Northeast Power Coordinating Council		NPCC	10										
6.	Mike Garton	Dominion Resources Services, Inc.		NPCC	5										
7.	Kathleen Goodman	ISO - New England		NPCC	2										
8.	Chantel Haswell	FPL Group, Inc.		NPCC	5										
9.	David Kiguel	Hydro One Networks Inc.		NPCC	1										
10.	Michael R. Lombardi	Northeast Utilities		NPCC	1										

Group/Individual	Commenter	Organization	Registered Ballot Body Segment											
			1	2	3	4	5	6	7	8	9	10		
11. Randy MacDonald	New Brunswick Power Transmission	NPCC 9												
12. Bruce Metruck	New York Power Authority	NPCC 6												
13. Lee Pedowicz	Northeast Power Coordinating Council	NPCC 10												
14. Robert Pellegrini	The United Illuminating Company	NPCC 1												
15. Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC 1												
16. David Ramkalawan	Ontario Power Generation, Inc.	NPCC 5												
17. Brian Robinson	Utility Services	NPCC 8												
18. Saurabh Saksena	National Grid	NPCC 1												
19. Michael Schiavone	National Grid	NPCC 1												
20. Wayne Sipperly	New York Power Authority	NPCC 5												
21. Tina Teng	Independent Electricity System Operator	NPCC 2												
22. Donald Weaver	New Brunswick System Operator	NPCC 2												
23. Ben Wu	Orange and Rockland Utilities	NPCC 1												
24. Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC 3												
2.	Group	Don Jones	Texas Reliability Entity											X
<b>Additional Member Additional Organization Region Segment Selection</b>														
1.	Curtis Crews	Texas Reliability Entity	ERCOT 10											
2.	David Penney	Texas Reliability Entity	ERCOT 10											
3.	Group	Jonathan Hayes	Southwest Power Pool Standards Development Team	X	X	X		X	X					
<b>Additional Member Additional Organization Region Segment Selection</b>														
1.	Jonathan Hayes	Southwest Power Pool	SPP NA											
2.	Robert Rhodes	Southwest Power Pool	SPP NA											
3.	Dan Lusk	Xcel Energy	SPP 1, 3, 5, 6											
4.	Julie Lux	Westar	SPP 1, 3, 5, 6											
5.	Mahmood Safi	OPPD	MRO 1, 3, 5											
6.	Roy Boyer	Xcel Energy	SPP 1, 3, 5, 6											
7.	Mitchell Williams	Western Farmers	SPP 1, 3, 5											
8.	John Pasierb	East Texas	NA - Not Applicable NA											
9.	David Kral	Xcel Energy	SPP 1, 3, 5, 6											
10.	Tom Hesterman	Westar	SPP 1, 3, 5, 6											

Group/Individual	Commenter	Organization	Registered Ballot Body Segment											
			1	2	3	4	5	6	7	8	9	10		
11. Tiffani Lake	Westar	SPP	6, 1, 3, 5											
12. Don Taylor	Westar	SPP	1, 3, 5, 6											
4. Group	Chris Higgins	Bonneville Power Administration	X		X		X	X						
<b>Additional Member Additional Organization Region Segment Selection</b>														
1. Charles	Sheppard		1											
2. Rebecca	Berdahl		3											
5. Group	Mike Garton	NERC Compliance Policy	X		X		X	X						
<b>Additional Member Additional Organization Region Segment Selection</b>														
1. Connie Lowe	NERC Compliance Policy	RFC	5, 6											
2. Michael Crowley	Electric Transmission	SERC	1, 3											
3. Jeff Bailey	Nuclear	MRO	5											
4. Sean Iseminger	F&H	SERC	5											
5. Chip Humphrey	F&H	NPCC	5											
6. Group	WILL SMITH	MRO NSRF	X	X	X	X	X	X						
<b>Additional Member Additional Organization Region Segment Selection</b>														
1. MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6											
2. CHUCK LAWRENCE	ATC	MRO	1											
3. TOM WEBB	WPS	MRO	3, 4, 5, 6											
4. JODI JENSON	WAPA	MRO	1, 6											
5. KEN GOLDSMITH	ALTW	MRO	4											
6. ALICE IRELAND	XCEL(NSP)	MRO	1, 3, 5, 6											
7. DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6											
8. ERIC RUSKAMP	LES	MRO	1, 3, 5, 6											
9. JOE DEPOORTER	MGE	MRO	3, 4, 5, 6											
10. SCOTT NICKELS	RPU	MRO	4											
11. TERRY HARBOUR	MEC	MRO	5, 6, 1, 3											
12. MARIE KNOX	MISO	MRO	2											
13. LEE KITTLESON	OTP	MRO	1, 3, 4, 5											
14. TONY EDDLEMAN	NPPD	MRO	1, 3, 5											
15. MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6											
16. THERESA ALLARD	MPC	MRO	1, 3, 5, 6											

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
7.	Individual	Antonio Grayson	Southern Company	X		X		X	X				
8.	Individual	Brenda Frazer	Edison Mission Marketing & Trading	X				X					
9.	Individual	John Bee	Exelon	X		X		X	X				
10.	Individual	Ray Phillips	Alabama Municipal Electric Authority				X						
11.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
12.	Individual	Dan Roethemeyer	Dynegy					X					
13.	Individual	Thad Ness	American Electric Power	X		X		X	X				
14.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
15.	Individual	Dale Fredrickson	Wisconsin Electric			X	X	X					
16.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
17.	Individual	Martin Kaufman	ExxonMobil Research and Engineering	X				X					
18.	Individual	Brian Murphy	NextEra Energy, Inc.	X		X		X	X				
19.	Individual	Jean Nitz	ACES Power Marketing						X				
20.	Individual	Patrick Brown	Essential Power, LLC					X					
21.	Individual	Russell A. Noble	Cowlitz County PUD			X	X	X					
22.	Individual	Michelle R. D'Antuono	Ingleside Cogeneration LP					X					

1. **The Project 2010-07 SDT considered Exelon’s appeal in the context of other stakeholder comments submitted in the first successive ballot between October 5 and November 18, 2011, along with advice from NERC staff. The SDT continues to believe that a reference to line of sight is clarifying and makes explicit the SDT’s implicit intent from day one. Thus, it kept the line of sight reference but made a few additional changes for formatting clarity and language consistency. The team also added a footnote to further explain what it means by “line of sight.” Do you agree with these changes? If not, please provide specific alternative language.**

#### Summary Consideration:

Some commenters still do not support the qualifying language for Generator Owners (GOs) or believe that the qualifying language should be worded differently. The SDT continues to believe that the qualifying criteria for GOs are appropriate; it has explained its rationale in depth in the posted [Technical Justification Document](#). The SDT has considered all relevant stakeholder comments, including many possible language options, and is satisfied that it has determined the appropriate language to address the reliability gap.

Some commenters suggested changes to items – including the content of the VSLs and the tables attached to the standard that were outside the scope of the SDT’s work.

Some commenters raised questions about the language differences between FAC-003-X and FAC-003-3 and expressed concern that the language in FAC-003-X could lead to a “null” result whereby the qualifying language is not applied according to the SDT’s intent. The SDT sought to keep the language of 4.3.1 of FAC-003-X consistent with the language in 4.2.1 of FAC-003-X. The SDT does not believe the language in Version X can lead to a “null” result; we believe the language is as clear as possible as written, now that it has been reformatted to better match the formatting in FAC-003-3.

Some commenters questioned whether “clear line of sight” means from a fixed point or from any point along the line. The SDT clarified that it intends for the phrase “from the generating station switchyard fence to the point of interconnection” to mean that there is a clear line of sight from any point along that length of line.

One commenter questioned whether the standard applies to all generator interconnection Facilities that a GO owns if it applies to one of them. The SDT clarified that it intended for the standard to apply on a line by line basis in both FAC-003-X and FAC-003-3. To clarify this, it has reformatted the Applicability section of FAC-003-X to better match the formatting in FAC-003-3.

One commenter asked whether the standard applies to the entirety of an applicable generator interconnection Facility, or just the portion of the line greater than one mile. The SDT clarified that if a GO owns an applicable line, the GO is responsible for the entirety of that line. The SDT believes that this is clear in the standards as written.

One commenter expressed concern that the implementation timeframe is too long. The SDT reminded the commenter that the time frame was based on previous stakeholder comments and the fact that the implementation of Version 0 standards – the transition into which marked the time that TOs needed to begin applying FAC-003 on a mandatory basis – occurred over more than two years. It is therefore reasonable to assume that GOs, having never had to comply with a vegetation management standard, be afforded adequate time to do so.

One commenter continues to find the changes proposed under Project 2010-07 to be unnecessary. As it has in previous consideration of comment reports, the SDT points out that it must act within the scope of the SAR for this project. As mandated by its SAR, the SDT has addressed standards for which there is a reliability gap or possible perception of a gap when it comes to the generator interconnection Facility, as justified in great depth in its [Technical Justification document](#).

The SDT considered all comments received and decided to address typos, improve the formatting of the Applicability section of FAC-003-X, and update the boilerplate language in the Effective Dates sections of the standards and their implementations plans. The SDT has proposed no substantive changes to the standards.

Organization	Yes or No	Question 1 Comment
Ameren Services	Negative	<p>(a) There is no technical basis for the one mile length exemption. In fact, one could argue that a very short line, 300 feet in length, that experienced a fault from a tree at "the end of the circuit", i.e near the switchyard fence, would have much more of an impact on the BES because the fault would be limited by much less impedance.</p> <p>(b) For the GO that owns several lead lines but only one of the lines is greater than one mile in length, does this standard apply to all the lead lines he owns? A response can be affirmative with the current language of the section 4.2.1. If this is not the intent, it should be clarified.</p> <p>(c) It is also unclear in this version if a GO that owned one line that was 1.2 miles in length would have to comply for the entire length of said line, or just 0.2 miles of said line. If the GO is responsible for 1.2 miles, then that</p>

Organization	Yes or No	Question 1 Comment
		<p>argues that the first mile is important and consequently there is no basis for ignoring the first mile on other lines. If the GO is only responsible for 0.2 miles, what is the technical basis to ignore a mile? And would it be the first mile from the switchyard that is ignored, or is the middle mile, or the last mile where it connects to the TO? Or could the GO decide? Or could the GO pick sections of the line that amount to a mile that they can ignore? This seems like something that should be addressed for compliance.</p> <p>(d) The 2 year compliance time line is far too long. There is significant industry evidence that was developed in the drafting of Version 2 that supports a one year compliance time-line for new lines. This is evidenced in Version 2. Thus there is no basis for the 2 years</p>
<p><b>Response: Thank you for your comment. The SDT continues to believe that the qualifying criteria for GOs are appropriate; it has explained its rationale in depth in the posted <a href="#">Technical Justification Document</a>. The SDT has considered all relevant stakeholder comments and is satisfied that it has determined the appropriate language to address the reliability gap.</b></p> <p><b>The SDT intended for the standard to apply on a line by line basis in both FAC-003-X and FAC-003-3. To clarify this, it has reformatted the Applicability section of FAC-003-X to better match the formatting in FAC-003-3.</b></p> <p><b>If a GO owns an applicable line, the GO is responsible for the entirety of that line. The SDT believes that this is clear in the standards as written.</b></p> <p><b>With respect to the Implementation Plan, the SDT reminds Ameren that the time frame was based on previous stakeholder comments and the fact that the implementation of Version 0 standards – the transition into which marked the time that TOs needed to begin applying FAC-003 on a mandatory basis – occurred over more than two years. It is therefore reasonable to assume that GOs, having never had to comply with a vegetation management standard, be afforded adequate time to do so.</b></p>		
BC Hydro and Power Authority	Negative	<p>“BC Hydro agrees with the revisions to FAC-003-3 and would vote Affirmative except for the following two items.</p> <p>One: The FAC-003-2 adopted by the NERC Board of Trustees had a significant change to what was voted on in Draft 6 in the Table of Compliance Elements (R1 and R2). In the table on Page 13 of the version</p>

Organization	Yes or No	Question 1 Comment
		<p>adopted by the NERC Board of Trustees on November 3, 2011, the VSLs were changed and the staff proposed violation severity levels were adopted and the review team recommendations were rejected. Therefore, there is no Low or Moderate VSLs for these two violations only High and Severe. This was rejected earlier by a number of utilities including BC Hydro and was not in the version 6 draft that was voted for on the last ballot. This change as adopted is a concern as it expects a level of program perfection that seems unrealistic. It is also at odds with the Rationale for R1 and R2 outlined on Page 32 of the standard “Guideline and Technical Basis” section which gives an explanation for the increasing levels of violation severity. Program failures that were deemed to be “unusual conditions in an otherwise sound program” or “not adequately addressed by the program” formerly rated as Lower or Moderate VSL are now rated as High. It also extends the severity of the violation beyond what is currently in FAC-003-1 although the levels of non-compliance are not strictly comparable between versions. This change is carried on in the Draft FAC-003-3.</p> <p>Two: Table 2 (pg. 30 and 31 of FAC-003-3 Draft 3) for Minimum Vegetation Clearance Distances for AC Voltages now includes clearance calculations for 287 kV which is good and was something BC Hydro asked for. However, the calculations don’t seem to be correct as the limits are higher than for 345kV. BC Hydro recommends either providing an explanation as to why these limits seem to be out of sequence to increasing voltage or recalculate them.”</p>
<p><b>Response:</b> Thank you for your comment. The SDT's SAR is very limited in scope (determining which additional standards should apply to a GO/GOP). The SDT made no changes to the VSLs and simply included the FAC-003-2 VSLs that were approved by NERC’s BOT, as those are the VSLs that will be filed with FERC. Similarly, the SDT made no changes to Table 2, as that would also have been outside its scope; the SDT exclusively made changes that would add GOs or GOPs to standard requirements or applicability sections, and changes that would bring the standard up to date according to current NERC templates. No change made.</p>		



Organization	Yes or No	Question 1 Comment
ComEd	Negative	Please refer to Exelon's comments submitted in the electronic comment form
PECO Energy	Negative	Please refer to Exelon's comments submitted in the electronic comment form
Gulf Power Company	Negative	See comments submitted via the electronic comments form by Antonio Grayson.
Mississippi Power	Negative	See comments submitted via the electronic comments form by Antonio Grayson.
Alabama Power Company	Negative	See comments submitted via the electronic comments form by Antonio Grayson.
Utility Services, Inc.	Negative	The applicability language under Version X is not the same as the language in Version 3. We do not believe that applicability language in Version X can ever result in a “True” logical outcome whereas the language in Version 3 can. We understand the intent; however, applying the specific language using the logical "AND" in the applicability portion of the standard will always come out with a null result. We suggest the SDT adopt the applicability language in Version 3 in Version X.
<p><b>Response: Thank you for your comment. The SDT sought to keep the language of 4.3.1 of FAC-003-X consistent with the language in 4.2.1 of FAC-003-X. The SDT does not believe the language in Version X can lead to a “null” result; we believe the language is as clear as possible as written now that it has been reformatted to better match the formatting in FAC-003-3. No change made.</b></p>		
Xcel Energy, Inc.	Negative	This project is counter-productive to the efforts of the Protection System Maintenance and Testing Standard Drafting Team that concurrently has

Organization	Yes or No	Question 1 Comment
		PRC-005-2 posted for comment and successive ballot.
<p><b>Response: Thank you for your comment. The SDT believes this comment was submitted in response to PRC-005 and will address it with comments received under that standard.</b></p>		
SERC Reliability Corporation	Negative	<p>We have concern that if this passes there will be BES Elements that will not be covered by the vegetation management standard that are currently included in the standards and that this determination is based solely on ownership and not risk to reliability. SERC supports BES reliability and as vegetation management was identified as a significant contributor to the 2003 Blackout we do not support a revision that would create a gap in the results-based, defense-in-depth approach that has been determined to be necessary for the reliable operation of the interconnected transmission network.</p>
<p><b>Response: Thank you for your comment. GOs are not currently covered under any vegetation management requirements, so the SDT does not understand the comment about removing coverage for BES Elements “that are currently included in standards.” The applicability to TOs, the entity currently subject to vegetation management requirements, is not changing. The SDT recognizes that in many cases, generation Facilities are (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale for exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. No stakeholder has commented that there are similarly situated transmission facilities.</b></p>		
Southern Company	No	<p>The requirement as worded implies or could be interpreted to mean one's line of site would have to originate at the generating station switchyard fence. The "clear line of site" should also include that from a roadway that travels in proximity to the line. Such a roadway's purpose would likely include access to the line for inspections, maintenance, travel from the plant to the transmission substation, etc. Since the terrain between the generating station switchyard fence and the point of interconnection could obscure the view from the fence, the clear line of site from such a roadway</p>

Organization	Yes or No	Question 1 Comment
		<p>should be allowed. The requirement should be revised to read, "...or (2) does not have clear line of sight<sup>1</sup> from the generating station switchyard fence or a roadway to the point of interconnection with a Transmission Owner's Facility."</p>
<p><b>Response: Thank you for your comment. The SDT appreciates this discussion, and had many similar discussions during its own deliberations. The SDT intends for the phrase "from the generating station switchyard fence to the point of interconnection" to mean that there is a clear line of sight from any point along that length of line. The SDT has considered all relevant stakeholder comments and is satisfied that it has determined the appropriate language to address the reliability gap. No change made.</b></p>		
<p>Southwest Power Pool Standards Development Team</p>	<p>No</p>	<p>Clear line of sight" means the distance that can be seen by the average person "standing at ground level "without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.</p>
<p><b>Response: Thank you for your comment. The SDT has considered all relevant stakeholder comments and is satisfied that we have determined the appropriate language to address the reliability gap.</b></p>		
<p>Cowlitz County PUD</p>	<p>No</p>	<p>Cowlitz must agree with Exelon’s position inasmuch that the vantage point must be related to the generating station switchyard maintenance or the operation and maintenance of the generation plant itself, and afford a clear perspective of vegetation proximity. Cowlitz also agrees with the SDT’s line of sight clarifying verbiage. However, restricting the vantage point to the generating station switchyard fence does not encompass the spirit of the exclusion. A short one-mile transmission interconnection line - from the generating station switchyard to the interconnection point - that is frequently viewed during the operation and maintenance of the generation plant itself should be the crux of the exemption.</p> <p>The exact location, i.e., the generating station switchyard fence, of the vantage point is not the make or break of whether the interconnection line will be routinely inspected by default. As an example, consider a hydro project where the generating station switchyard may be located near the</p>

Organization	Yes or No	Question 1 Comment
		<p>tailrace inside a canyon. From the fence line of this particular switchyard, only the interconnection line traversing up the canyon wall is visible. However, topside of the dam where maintenance and operational personnel must daily traverse under the interconnection line to access the powerhouse and switchyard may afford a clear view of both the generating station switchyard below and the interconnection station which includes the whole interconnecting line in-between.</p> <p>Further, if parts of the interconnecting line is viewable in two or even three vantage points beneath the interconnection line during the normal transit to and from the generating station switchyard, the sum of which comprises the whole line, can this not also meet the spirit of the exclusion?</p> <p>Conversely, Cowlitz does not hold that any vantage point should be acceptable. Any vantage point that must require special effort to access no matter the ease is not acceptable. Also, a perpendicular view of a line (not under or near) complicates perception of the proximity of vegetation to a line. Views parallel down the right-of-way maximizes perception of vegetation proximity.</p> <p>Further, a long line that is fully viewable during transit to and from the generation plant increases the chance of hidden vegetation encroachment. Cowlitz strongly opposes any trivializing of reliability compliance collateral damage. Forcing compliance activities with no reliability return must be avoided wherever possible. As a stakeholder with limited time to invest reviewing all the comments submitted, Cowlitz offers an apology to Exelon for missing their initial comment. Cowlitz commends Exelon’s persistence in this matter.</p> <p>***Suggested language: ...or (2) do not have a clear line of sight (leave the footnote in place) up and/or down from a single vantage point within the transmission right-of-way where both the origin at the generating station switchyard and the termination interconnection point with the Transmission</p>

Organization	Yes or No	Question 1 Comment
		Owner’s Facility can be seen, and where operations or maintenance personnel frequent on foot during normal generation plant or generating station switchyard access is made...
<p>Response: Thank you for your comment. The SDT appreciates this discussion, and had many similar discussions during its own deliberations. The SDT intends for the phrase “from the generating station switchyard fence to the point of interconnection” to mean that there is a clear line of sight from any point along that length of line. We do not believe that adding the language you suggest necessarily adds clarity, and we’re concerned that it may raise additional questions. In sum, the SDT has considered all relevant stakeholder comments and is satisfied that we have determined the appropriate language to address the reliability gap. No change made.</p>		
Exelon	No	<p>Exelon disagrees with the current proposed draft of FAC-003-3/X because the reference to a “clear line of sight from the generating station switchyard fence to the point of interconnection” does not clarify the Standard and is unsupported by any technical basis. Furthermore, the definition of “clear line of sight” added by the SDT does not address or remedy the substantive concerns raised in Exelon’s appeal.</p> <p>Exelon reiterates that the SDT should base the applicability of the Standard on the length of the transmission line, a measurable component of the bulk electric system, and remove all references to a “clear line of sight.” This approach is consistent with previous draft versions of FAC-003 proposed by the SDT and the Ad Hoc Group and the recent recommendation of the NERC Vice President of Standards and Training in response to Exelon’s appeal.</p> <p>Alternatively, if the “clear line of sight” verbiage remains, the Standards should be clarified to remove the requirement that the line of sight be established from “the generating station switchyard fence to the point of interconnection” and to add a requirement or clarify that “clear line of sight” for lines of one mile or less can include observation of the length of the transmission lines from various vantage points within the owner controlled property. The SDT states in the “Background” section of the</p>

Organization	Yes or No	Question 1 Comment
		<p>Unofficial Comment Form that “a reference to the line of sight is clarifying and makes explicit the SDT’s implicit intent from day one.”</p> <p>Yet, the SDT offers no support for its “implicit intent from day one,” and a review of the history for these Standards certainly does not support an “implicit intent from day one” to require a clear line of sight from a fixed location, let alone the generating station switchyard fence, to the point of interconnection. The Technical Justification document posted in September 2011 (p. 3) refers to the Ad Hoc Group’s original thought to exclude from the Standards any transmission lines that were “less than two spans [long] (generally one half mile from the generator property line).” In agreeing “with that intended exclusion in principle,” the SDT explained (p. 3) that, “[a]fter reviewing formal comments, the SDT agreed to revise the exclusion so that it applies to a Facility [transmission line] if its length is ‘one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard’ to approximate line of sign [sic] from a fixed point,” (the fixed point being the fenced area of the generating station switchyard). From the start, the Ad Hoc Group and SDT focused on the length of the transmission line (either a half mile as proposed by the Ad Hoc Group or a mile as proposed by the SDT) as the proxy for line of sight, the presumption being that up to a certain distance, the overhead line is in the line of sight at various locations throughout the Generator Owner’s property and reasonably subject to being managed through normal day-to-day plant activities.</p> <p>The SDT has not, until the most recent iteration of the Standards, focused on requiring a “clear line of sight from the generating station switchyard fence to the point of interconnection.” As support for adding the “clear line of sight” requirement to the FAC-003-3/X Standards in December 2011, the SDT noted as follows: “We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and</p>

Organization	Yes or No	Question 1 Comment
		<p>any discretion on the part of a Generator Owner or an auditor.” With the addition of an explicit line of sight reference here, the SDT believes it has clarified its original intent. (Side bar comments to FAC-003-3, Section 4.3.1 (December 1, 2011); FAC-003-X, Section 4.3.1 (December 1, 2011)).</p> <p>This explanation does nothing more than (1) reiterate the point the SDT has maintained throughout the entire drafting process, namely that “the one mile length” of a transmission line “is a reasonable approximation of line of sight,” and (2) explain that the SDT included a “fixed starting point” (the fenced area of the generation station switchyard) from which to measure the length of the transmission line to address stakeholder concerns about excessive Generator Owner discretion with respect to the location from which to take a measurement and inconsistent application of the Standards.</p> <p>Again, the SDT’s “intent” (implicit or otherwise) “from day one” has nothing to do with establishing a “clear line of sight from the generating switchyard fence to the point of interconnection.” In addition, requiring a “clear line of sight from the generating station switchyard fence to the point of interconnection” is technically unsupported. The SDT just added the requirement for a “clear line of sight to the point of interconnection” language without considering the implications of why such a change was required or reasonable. While a specific fixed starting point (the generating station switchyard fence) and end point (the point of interconnection) may make sense for establishing a starting and ending point from which to measure the length of the transmission line (the one-mile limitation), it does not make sense when considering a clear line of sight, especially in light of stakeholder comments and the SDT’s repeated acknowledgment that in many cases, generation Facilities are either (1) staffed and the overhead portion is within the line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that</p>

Organization	Yes or No	Question 1 Comment
		<p>these qualifiers represent a reasonable and appropriate risk prevention approach.(Consideration of Comments, Generator Requirements at the Transmission Interface, Project 2010-07 (for November 9, 2011 successive ballot), p. 1; Technical Justification Resource Document (posted March 2012), p. 3.)</p> <p>By inserting the “clear line of sight” requirement now without modifying the fixed starting point, the SDT completely ignores its unequivocal acknowledgment that generation Facilities are unique in the sense that personnel can see the line from various locations within the owner controlled area and many generation Facilities are over paved surfaces. The absence of a technical justification for imposing a “clear line of sight” is illustrated by the following example.</p> <p>A Generator Owner transmission line leaving the generating station could take a “dog leg” turn (the line turns at one of the towers). Standing at the tower in this example, an individual would have a clear line of sight of the entire line to either end of the short-distance line (to the end leaving the station and to the end terminating at the point of interconnection). Since the generating Facility is within the Generator Owner’s property line or controlled area and consistently staffed by personnel who patrol the owner controlled area, the line can be observed and maintained by staff in the same manner as any other short distance line with a “clear” line of sight from the “generating station switchyard fence to the point of interconnection.” Moreover, to the extent a portion or the entire length of the line travels over paved surfaces or structures, any barriers or obstacles to a clear line of sight will not be caused by vegetation, as discussed in FAC-003-3/X but, rather, by equipment, components, or structures. Clearance between generator lines and structures is already covered in other NERC Standards. For those lines that do travel over areas of vegetation, the regular personnel monitoring and surveillance of the areas over which the lines travel provides reasonable assurance of protection from vegetation</p>



Organization	Yes or No	Question 1 Comment
		<p>related events.</p> <p>Rather than clarifying the Standards, the SDT has introduced more ambiguity into the Standards. The addition of the “generating station switchyard fence” as the point of reference for a clear line of sight adds more confusion than it solves by introducing a variable that will be left to the discretion of generator owner and an auditor. What is the definition of a “generating station switchyard fence?” As Exelon noted in its Appeal and at least one other Registered Entity noted in its Comments for the first successive ballot (Consideration of Comments posted March 2012, p. 38), some generation facilities do not have generating switchyards or generating switchyard fences. A requirement that there be a clear line of sight from the “generating switchyard fence” is meaningless in cases where no such switchyard or fence exists. Is it the fence surrounding the generating unit or is it meant to refer to the fence surrounding the Transmission Owner’s associated switchyard and relay house? What if there are multiple physical fence lines between the generating unit and the point of interconnection? In addition, by introducing a point of reference that is not a physical component or measurable reference of the bulk electric system, what precludes the Generator Owner from arbitrarily moving the fence line to avoid applicability? Also lacking in clarity is the addition of a footnote defining “clear line of sight” to mean “the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.” Generation Owners will be left to determine what constitutes an “average person,” a “clear day,” and “special instrumentation.”</p> <p>For all these reasons, Exelon requests that the SDT base the applicability of the Standard on the length of the transmission line, a measurable component of the bulk electric system, and remove all references to a “clear line of sight.” Alternatively, if the “clear line of sight” verbiage remains, the Standards should be clarified to remove the requirement that</p>

Organization	Yes or No	Question 1 Comment
		<p>the line of sight be established from “the generating station switchyard fence to the point of interconnection” and to add a requirement or clarify that “clear line of sight” for lines of one mile or less can include observation of the length of the transmission lines from various vantage points within the owner controlled property.</p>
<p><b>Response:</b> Thank you for your comment. The SDT appreciates this discussion, and had many similar discussions during its own deliberations. We maintain that the addition of the reference to “clear line of sight” is clarifying and helps support the rationale behind the one mile exemption. A line less than one mile that passes through a dense grove should not be exempt from this standard, but a line that is less than one mile and is either (1) staffed and within line of sight or (2) over a paved surface <i>should</i> be exempt.</p> <p>The SDT intends for the phrase “from the generating station switchyard fence to the point of interconnection” to mean that there is a clear line of sight from any point along that length of line. We do not believe that adding a reference to a fixed vantage point necessarily adds clarity, and we’re concerned that it may raise additional questions. In sum, the SDT has considered all relevant stakeholder comments and is satisfied that we have determined the appropriate language to address the reliability gap. No change made.</p>		
Texas Reliability Entity	No	<p>In FAC-003-X:</p> <ol style="list-style-type: none"> <li>1. We appreciate that you took Regional Entity out of the Applicability section, but there is still a Requirement (R4) that applies to the Regional Entity. Is that Requirement intended to be enforceable against the Regional Entities? We suggest removing Requirement R4.</li> <li>2. In Part D.1.1, only the Regional Entity should be listed as Compliance Monitor, since the Regional Entity has been removed as an Applicable entity.</li> <li>3. In the Purpose section, update the reference to NERC (use “Corporation” instead of “Council”), and capitalize “Rights-of-Way” since it is a defined term.</li> </ol>

Organization	Yes or No	Question 1 Comment
		<p>4. We suggest that you spell out “Regional Entity” in Applicability part 4.2.1.</p> <p>5. In the implementation plan, the reference to “R3” should be corrected to “R1” in the following sentence: “In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.”</p> <p>In FAC-003-3:</p> <p>6. There is no Compliance Monitor listed on page 17. At least the Regional Entity should be listed here.</p> <p>7. In the Severe VSL for R2, replace “Transmission Owner” with “responsible entity.”</p> <p>8. In the Severe VSL for R1 and R2, remove “active transmission line” before “ROW.” That phrase is confusing in the VSLs because it does not appear in the requirements, and it is not clear whether it is intended to change the requirements.</p> <p>9. In Table 2 (Alternating Current - meters AND Direct Current) the footnote references are wrong. We think they should be 9 and 10, rather than 7 and 8.</p> <p>10. In Table 2 (Direct Current), the column headings are wrong. Only the first column heading should refer to voltage. The rest should refer to MVCD.</p>
<p><b>Response: Thank you for your comment.</b></p> <ol style="list-style-type: none"> <li>1. The SDT has reverted back to the original Applicability (which included the Regional Entity) because deleting a requirement is outside the scope of this drafting team.</li> <li>2. Because the Regional Entity was returned to the Applicability section, the second bullet in section D1.1 must remain.</li> <li>3. Changes made.</li> <li>4. Regional Entity has been spelled out in all cases.</li> </ol>		

Organization	Yes or No	Question 1 Comment
<p>5. Change made.            6. The Compliance Enforcement Authority section has been updated as suggested.            7. Change made.            8. Modifying the VSLs beyond the change from “Transmission Owner” to “responsible entity” is not within the scope of the SDT, and these VSLs have already been approved by NERC’s BOT.            9. These are 9 and 10 in both the clean version and the redline version.            10. The Project 2010-07 SDT did not modify this table.</p>		
Manitoba Hydro	No	<p>Manitoba Hydro does not support the changes being proposed in Project 2010-07. If a Generator Owner is required to register as a TO, all the Requirements applicable to a TO should apply. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. For additional information, please see Manitoba Hydro's comments submitted in the comment period ending November 18, 2011. Manitoba Hydro does not believe that the SDT fully addressed our concerns in their responses to our comments in that commenting period.</p>
<p><b>Response:</b> Thank you for your comment. Under the SDT’s changes, GOs are not going to be required to register as TOs, so this comment does not apply.</p> <p>To reiterate our comments in previous comment reports, the intent of the SDT’s SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT determined that it should first address “low-hanging fruit” and believes these to be sole-use Facilities (see posted examples under “Supporting Materials” posted alongside the December ballot) – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP). Through our deliberations, we came to the conclusion that an interconnection Facility owned or operated by a GO or GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT.</p> <p>The SDT also refers the commenter to the document titled <a href="#">Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document</a>.</p>		
Liberty Electric Power LLC	No	The "line of sight" should be removed. It opens up the entity to a finding of

Organization	Yes or No	Question 1 Comment
		non-compliance if a temporary blockage of line of sight should occur.
<p>Response: Thank you for your comment. We maintain that the addition of the reference to “clear line of sight” is clarifying and helps support the rationale behind the one mile exemption. A line less than one mile that passes through a dense grove should not be exempt from this standard, but a line that is less than one mile and is either (1) staffed and within line of sight or (2) over a paved surface <i>should</i> be exempt. Nothing in the proposed standard prohibits an entity from self-imposing the requirements contained within in order to mitigate any perceived risk of potential non-compliance. No change made.</p>		
Northeast Power Coordinating Council	No	<p>The Applicability language used in FAC-003-X is different from that used in FAC-003-3. The language used in FAC-003-X uses “and” in several places which leads to confusion and a probable “null” result, whereas the language in FAC-003-3 is more straightforward and makes use of “or”. The FAC-003-3 applicability language should be used in FAC-003-X. The explanation of what is meant by line of sight should be incorporated in the Applicability Section wording as standards, at NERC’s direction, are supposed to be getting away from the use of footnotes.</p>
<p>Response: Thank you for your comment. The SDT sought to keep the language of 4.3.1 of FAC-003-X consistent with the formatting in 4.2.1 of FAC-003-X. The SDT does not believe the language in Version X can lead to a “null” result; we believe the language is as clear as possible as written now that the formatting has been updated to better reflect the formatting in FAC-003-3. No change made.</p>		
NextEra Energy, Inc.	No	<p>Under the line of sight approach, a generation lead would be exempt from the requirements of FAC-003-3 if personnel can see the generation lead corridor and the generation lead is less than a mile. The rationale provided to support of this proposal is that “Stakeholders have generally supported the rationale for exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit.”</p> <p>However, there is no data that supports that generation leads of less than a mile are categorically not subject to vegetation contacts and outages. Further, in practice this approach will unduly discriminate against longer</p>

Organization	Yes or No	Question 1 Comment
		<p>generator leads, many of which are associated with renewable energy resource, such as wind and solar.</p> <p>NextEra Energy Inc. (NextEra) believes a more technically sound approach is that all generator leads be subject to FAC-003-3, with the opportunity to be exempted from FAC-003-3 regulation upon an affirmative demonstration that no vegetation threat exists.</p> <p>To implement this approach, NextEra proposes that FAC-003-3 applicability 4.3.1 be revised to read as follows: “Overhead transmission lines, including generation leads, beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner and are:4.3.1.1. Operated at 200kV or higher; or 4.3.1.2. Operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator; or. 4.3.1.3. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.”</p> <p>NextEra would also propose to add a new section 4.3.2 that reads as follows:”If a Generator Owner or Transmission Owner can demonstrate that the entire Right-of-Way is paved or otherwise devoid of vegetation, and reasonably expected to remain so, the Generation Owner or Transmission Owner is exempt from FAC-003-3.”</p> <p>In addition, NextEra proposes that the drafting team consider a megawatt (MW) threshold for a generating plant from both a stand-alone and aggregate bases. For example, it is unlikely that vegetation contact tripping a 50 megawatt generator (or a generator of 100 MWs in the aggregate) connected to a robust transmission system with a large amount of load and generation will adversely impact reliability.</p> <p>Thus, NextEra proposes the addition of a provision that exempts a generation lead for stand-alone generators of 50 MWs and below and</p>

Organization	Yes or No	Question 1 Comment
		<p>generators in the aggregate of 100 MWs and below, unless there is an affirmative request for the generator to comply with FAC-003-3 by a Transmission Operator or Reliability Coordinator. Such a provision could read as follows: "Unless a Transmission Operator or Reliability Coordinator requests in writing that a stand-alone generator of 50 Megawatts (MWs) or below (with a 200 kV or above generation lead) or a generator in the aggregate of 100 MWs or below (with a 200 kV or above generation lead) comply with FAC-003-3, these classes of generators and their associated generation leads are exempt from complying with FAC-003-3. In the event a Transmission Operator or Reliability Coordinator requests in writing that a stand-alone generator of 50 Megawatts (MWs) or below (with a 200 kV or above generation lead) or a generator in the aggregate of 100 MWs or below (with a 200 kV or above generation lead) comply with FAC-003-3, the associated registered entity shall have one-year from the date of the written correspondence to come into compliance with FAC-003-3."</p>
<p><b>Response:</b> Thank you for your comment. The SDT appreciates this discussion, and had many similar discussions during its own deliberations. We maintain that the addition of the reference to "clear line of sight" is clarifying and helps support the rationale behind the one mile exemption. A line less than one mile that passes through a dense grove should not be exempt from this standard, but a line that is less than one mile and is either (1) staffed and within line of sight or (2) over a paved surface <i>should</i> be exempt. And because there are many GOs whose lines would fall into these categories, the SDT believes the exemption is necessary and prevents GOs with little to no reliability risk from incurring undue cost and compliance risk in the development and maintenance of a vegetation management plan. In sum, the SDT has considered all relevant stakeholder comments and is satisfied that we have determined the appropriate language to address the reliability gap. No change made.</p>		
Dynergy	No	<p>Using the switchyard fence is too restrictive. There could be too many different layouts to keep it fair for all GO's. For example, there could be an obstruction if limited to standing at the existing switchyard fence but if one were to move a short distance away (i.e. corner of GO's building) then it could be possible to see both ends of the tie line. This would also meet the intent of the added language since it is now within line of sight. I</p>

Organization	Yes or No	Question 1 Comment
		recommend deleting "switchyard fence". Also, in order to account for a GO not being able to dictate what happens inside a TO's switchyard, I recommend adding "entry or" between "of" and "interconnection".
<p><b>Response:</b> Thank you for your comment. The SDT appreciates this discussion, and had many similar discussions during its own deliberations. The SDT considered many options for a starting point, and believes that using the fixed starting point of the switchyard fence is best for eliminating confusion and any discretion on the part of a Generator Owner or an auditor. The SDT intends for the phrase “from the generating station switchyard fence to the point of interconnection” to mean that there is a clear line of sight from any point along that length of line. In sum, the SDT has considered all relevant stakeholder comments and is satisfied that we have determined the appropriate language to address the reliability gap. No change made.</p>		
Wisconsin Electric; Wisconsin Electric Power Co.; Wisconsin Electric Power Marketing; Wisconsin Energy Corp.	No	We strongly oppose the addition of the “clear” line of sight criteria to the Applicability. The report of the GOTO Task Force, as well as prior draft revisions to FAC-003, included a test based solely on circuit length, which is sufficient in our view to assure that the BES is not at risk due to vegetation issues on generator tie lines. The expansion to include short tie lines, including those entirely on the Generator Owner’s property which may not meet the line of sight qualifier, has no benefit to reliability. Rather, the expanded applicability and the requirement for a formal vegetation management program in these cases will consume resources for compliance that are better used for actual reliability improvements.
<p><b>Response:</b> Thank you for your comment. The SDT appreciates this discussion, and had many similar discussions during its own deliberations. We maintain that the addition of the reference to “clear line of sight” is clarifying and helps support the rationale behind the one mile exemption. A line less than one mile that passes through a dense grove should not be exempt from this standard, but a line that is less than one mile and is either (1) staffed and within line of sight or (2) over a paved surface <i>should</i> be exempt. The SDT has considered all relevant stakeholder comments and is satisfied that we have determined the appropriate language to address the reliability gap. No change made.</p>		
ExxonMobil Research and Engineering	No	While it is clear that the SDT is attempting to include those facilities owned by Generator Owners that travel long distances down right-of-ways, the



Organization	Yes or No	Question 1 Comment
		<p>applicability section of FAC-003-X and FAC-003-3, as written, require industrial complexes with cogeneration facilities to develop Transmission Vegetation Management Programs for generator lead lines that are not exposed to vegetation.</p> <p>Industrial cogeneration location is typically chosen based on the availability of fuel, need for steam, or availability of real estate. This can result with the generation facilities (including the GSU transformer substation) being located deep within the plant with long cable routes and multiple substation connections between the GSU transformer substation and utility interconnection facility located near the perimeter of the industrial complex’s fence line. Additionally, the routes of these generator lead lines fundamentally differ in nature from a typical IPP’s generator lead line route. Since they are located within the fence line of an industrial complex, the routes rarely contain vegetation; are frequently travelled by plant personnel; rarely run in straight lines (i.e. no single line of sight); and frequently terminate at a facility located at the fence line of the industrial complex where a transmission company takes ownership of the power lines that leave the industrial complex. Furthermore, the use of the term “generating station switchyard” may result in inconsistent enforcement of the Transmission Vegetation Management Program Reliability Standard as the use of the term implies there is only one substation located within a Generator Owner’s complex. Typically, there are multiple substations that connect an industrial complex’s generator lead-line to the utility interconnection facility located near the perimeter of the industrial complex’s fence line. The two obvious interpretations for the “generating station switchyard” are the substation that is directly connected to the generator’s GSU, and the utility interconnection facility. The concerns raised by NERC and FERC staff related generator owned transmission like assets originate with those conductors that leave the Generator Owner’s complex’s fence line and travel long distances down vacant right-of-ways,</p>

Organization	Yes or No	Question 1 Comment
		<p>and, therefore, the applicability of those Reliability Standards that apply to transmission facilities should start with the fence line.</p> <p>Since the Bulk Electric System is contiguous, reliability concerns related to the facilities between the GSU transformer substation and utility interconnection facility are covered by those Reliability Standards that apply to Generator Owners and Generator Operators. In order to account for the different nature of industrial complex's generation facilities, the SDT should consider re-phrasing the applicability section of FAC-003-X and FAC-003-3 to start counting the length of a generator lead line at the fence line of the Generator Owner's complex and not the generating station switchyard.</p>
<p><b>Response: Thank you for your comment. The SDT appreciates this discussion, and had many similar discussions during its own deliberations. The SDT considered many options for a starting point, and for language in general within this qualifier, and it believes that using the fixed starting point of the switchyard fence is best for eliminating confusion and any discretion on the part of a Generator Owner or an auditor. In sum, the SDT has considered all relevant stakeholder comments and is satisfied that we have determined the appropriate language to address the reliability gap, while exempting the most common lines with little to no reliability risk for a vegetation issue. No change made.</b></p>		
<p>City of Bartow, Florida; City of Clewiston; Florida Municipal Power Agency; Beaches Energy Services</p>	<p>Affirmative</p>	<p>Although we are supporting the change, the added applicability language for GOs is ambiguous as to whether the qualifier "operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region" applies to both portions of the applicability (e.g., 1) &gt; 1 mile and 2) no clear line of sight), or just to the second no clear line of sight applicability. FMPA assumes that the qualifier applies to both. We recommend re-arranging of the sentence to make this clearer by moving the qualifier to the beginning of the sentence instead of the end of the sentence.</p>
<p><b>Response: Thank you for your comment. The SDT agrees that the qualifier applies to both (1) and (2) in the qualifier language and used that language formatting to keep the formatting of 4.2.1 of FAC-003-X consistent with 4.1.1 of FAC-003-X. No change</b></p>		

Organization	Yes or No	Question 1 Comment
made.		
American Wind Energy Association	Affirmative	<p>AWEA supports the modifications in this standard, along with the other standards modification under Project 2010-07, as a reasonable approach to addressing the perceived reliability concerns with generator tie lines. We believe a consistent approach for all Generator Owners and Generator Operators that does not require registration as a Transmission Owner or Transmission Operator is the most efficient and effective way to address these concerns.</p>
<p><b>Response: The SDT thanks you for your comment and support.</b></p>		
BrightSource Energy, Inc.	Affirmative	<p>BrightSource would like to thank the SDT for the effort in developing the standard. Our comment is more on providing more clarification. Depending on the agreements between the TO and the GO, the Point of Interconnection is not necessarily the point of change of ownership of the transmission facilities. For example, the GO may own the portion of the Gen-tie from the generating plant to the last tower outside the TO’s substation and the TO owns the line drop from the last tower to the termination equipment inside the TO substation. So to avoid confusion later we suggest that we modify P4.3.1 by adding “to the point of change of ownership or” as follows: “4.3.1. Generator Owner that owns an overhead transmission line(s) that (1) extends greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of change of ownership or to the point of interconnection with a Transmission Owner’s Facility or (2) does not have a clear line of sight<sup>1</sup> from the generating station switchyard fence to the point of interconnection with a Transmission Owner’s Facility and is operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.” Thank you.</p>

Organization	Yes or No	Question 1 Comment
<p><b>Response: The SDT thanks you for your comment and support. The SDT considered many different language choices for its qualifying language, and it believes that “point of interconnection” is a clear phrase that will be understood and appropriately applied. No change made.</b></p>		
<p>Indiana Municipal Power Agency</p>	<p>Affirmative</p>	<p>IMPA supports the change, but would add the comment that the added applicability language for GOs is ambiguous as to whether the qualifier "operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region" applies to both portions of the applicability which are 1) &gt; 1 mile and 2) no clear line of sight), or just to the second portion for no clear line of sight applicability. IMPA assumes that the qualifier applies to both. We recommend reorganizing the sentence to make this more clear by moving the qualifier to the beginning of the sentence.</p>
<p><b>Response: Thank you for your comment. The SDT agrees that the qualifier applies to both (1) and (2) in the exemption language and used that language formatting to keep the formatting of 4.2.1 of FAC-003-X consistent with the formatting in 4.1.1 of FAC-003-X. No change made.</b></p>		
<p>Nebraska Public Power District</p>	<p>Affirmative</p>	<p>NPPD joins the comments submitted by the MRO NSRF (Midwest Reliability Organization - NERC Standards Review Forum)</p>
<p>Midwest Reliability Organization</p>	<p>Affirmative</p>	<p>Please refer to comments made by MRO NSRF.</p>
<p>Muscatine Power &amp; Water</p>	<p>Affirmative</p>	<p>Please see comments submitted by the MRO NERC Standards Review Forum.</p>
<p>Lakeland Electric</p>	<p>Affirmative</p>	<p>See FMPA comments</p>
<p>Great River Energy</p>	<p>Affirmative</p>	<p>See NSRF comments</p>
<p>Bonneville Power Administration</p>	<p>Yes</p>	<p>BPA has no other comments or concerns at this time.</p>

Organization	Yes or No	Question 1 Comment
NERC Compliance Policy	Yes	<p>Dominion offers the following comments on the Implementation Plan for FAC-003-3:</p> <ol style="list-style-type: none"> <li>1. The last paragraph on page 2 refers to FAC-003-3 Requirement 1.3. FAC-003-3 does not appear to contain a Requirement 1.3; therefore, Dominion recommends that the reference in the Implementation Plan be clarified.</li> <li>2. The 3rd paragraph on page 3 refers to FAC-003-3 Requirement 1.2. FAC-003-3 does not appear to contain a Requirement 1.2; therefore, Dominion recommends that the reference in the Implementation Plan be clarified.</li> </ol>
<p><b>Response: Thank you for these suggestions. These references have been removed.</b></p>		
MRO NSRF	Yes	<p>The NSRF agrees with the clarifying changes related to adding the phrase “.....do not have a clear line of sight from the generating station switchyard fence to the point of interconnection with a Transmission Owner’s Facility.....”, however, have the following comment for SDT consideration:</p> <ul style="list-style-type: none"> <li>o The Evidence Retention in FAC-003-3, Part C, Compliance, and Section 1.2 implies that an entity is required to retain evidence for the time period since the last audit. Since Generator Owners’ audit cycles are six (6) years, and the following paragraph states that to show compliance for R1, R2, R3, R5, R6 and R7 is three calendar years unless directed by the CEA to retain longer as part of an investigation, this section should be clarified to require six years retention for applicable Generator Owners.</li> </ul>
<p><b>Response: Thank you for your comment. The SDT believes the data retention section is appropriate as written. No change made.</b></p>		
Edison Mission Marketing & Trading	Yes	
Alabama Municipal Electric Authority	Yes	

Organization	Yes or No	Question 1 Comment
American Electric Power	Yes	
Public Service Enterprise Group	Yes	
ACES Power Marketing	Yes	
Essential Power, LLC	Yes	
Ingleside Cogeneration LP	Yes	

END OF REPORT

February 14, 2012

Via E-Mail

Mr. Steven T. Naumann  
Vice President, Wholesale Market Development  
Federal Regulatory Affairs & Public Policy  
Exelon Corporation  
Chase Tower-50th Floor  
10 S. Dearborn Street  
Chicago, Il 60603

Re: Exelon Level 1 Appeal of FAC-003x in Project 2010-07

Dear Steve,

In my role as Director of Standards you informed me, on January 13, 2012, of the possibility of filing an appeal. On January 20, 2012 you filed, on the behalf of Exelon Corporation, a Level 1 Appeal of the processing of FAC-003 in Project 2010-07 under the NERC standards development process and the Rules of Procedure Section 300. In its appeal Exelon is contending that there was an improperly implemented, substantive change to the standard (R4.3.1) regarding "line of site" between the last successive and recirculation ballot.

Level 1 Appeals are managed within the current NERC Standard Processes Manual (SPM) dated September 3, 2010 as follows:

- Any entity that has directly and materially affected interests and that has been or will be adversely affected by any procedural action or inaction related to the development, approval, revision, reaffirmation, or withdrawal of a reliability standard, definition, variance, associated implementation plan, or interpretation shall have the right to appeal. This appeals process applies only to the NERC reliability standards processes as defined in this manual, not to the technical content of the standards action.

The burden of proof to show adverse effect shall be on the appellant. Appeals shall be made within 30 days of the date of the action purported to cause the adverse effect, except appeals for inaction, which may be made at any time.

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Suite 600, North Tower  
Atlanta, GA 30326  
404-446-2560 | [www.nerc.com](http://www.nerc.com)

The final decisions of any appeal shall be documented in writing and made public.

The appeals process provides two levels, with the goal of expeditiously resolving the issue to the satisfaction of the participants.

- **Level 1 Appeal**  
Level 1 is the required first step in the appeals process. The appellant shall submit (to the Director of Standards) a complaint in writing that describes the procedural action or inaction associated with the standards process. The appellant shall describe in the complaint the actual or potential adverse impact to the appellant. Assisted by staff and industry resources as needed, the Director of Standards shall prepare a written response addressed to the appellant as soon as practical but not more than 45 days after receipt of the complaint. If the appellant accepts the response as a satisfactory resolution of the issue, both the complaint and response shall be made a part of the public record associated with the standard.

The FAC-003-x standard had been scheduled for Board of Trustees approval at its February 9, 2012 meeting, however, in order to permit the Level 1 Appeal process to properly run, it has been withdrawn.

### **Information Requests**

In response to the Level 1 Appeal, three information requests, each containing two questions, were issued on January 25, 2012. One was issued to Exelon, one to NERC Standards Process Staff and one to the Project 2010-07 Standards Drafting Team (SDT) Chair. The information requests and the responses are appended to this letter which will be posted on the NERC website.

### **Findings**

#### ***Timeliness of the Appeal:***

The Standard Processes Manual calls for the filing of the appeal within 30 days of the date of the action purported to cause the direct material adverse impact. The standard with the “line of site change” was posted on December 14, 2011 and the ballot was finalized on December 23, 2011.

Within the project notice posted on December 14, 2011 it was clearly stated:

“In FAC-003-X and FAC-003-3, the SDT added a clarifying reference to line of sight in the GO exemption in section 4.3.1. of both versions; corrected a typo in 4.3.1.2 of FAC-003-3; and changed “RE” to “Regional Entity” in 4.3.1 of FAC-003-X.”



In its response to the first information request Exelon notes its position that the adverse impact did not occur until the ballot was concluded (unfavorably in Exelon's view). On this basis Exelon believes its January 13, 2012 preliminary notice of intent to file an appeal and the January 20, 2012 filing of the appeal was timely under the SPM. I will consider the filing of this Level 1 Appeal as having been made timely.

***Adverse Impact:***

Exelon notes in its response to Information Request 1 that it considers the direct material adverse impact to be that it would be now subject as a Generator Owner/Generator Operator (GO/GOP) to the proposed FAC-003-x standard given the line of sight clarification. It is a fair question as to whether having a standard become applicable to a given entity is truly an adverse impact? If that were the case, then every registered function would contend the same. I find that it is not an adverse impact for a subset of Exelon's nuclear facilities to become subject to the standard. Applicability by itself is not an adverse impact. The interests of reliability must be served and if the SDT determines that a given set of circumstances should result in a standard becoming applicable, then that is the technical design. On the basis of applicability the appeal fails. The SDT in this project was charged specifically with the task of determining which standards and requirements should be adjusted (and how they should be adjusted) for applicability to GOs/GOPs.

***Procedural Action:***

Exelon believes that it did not have ample time to respond to the proposed change. Exelon contends it was denied the ability to inform the industry. Exelon did provide some information of its efforts to inform the industry of its beliefs, although apparently it was unpersuasive, given the outcome of the ballot.

***Material Change:***

Based on the information request response from the SDT Chair, the SDT believes that the "line of sight" change it made was clarifying and not material. I agree with Exelon, however that the line of sight change also had the effect of changing the applicability of the standard based on its construct as Exelon contends. This is within the technical scope for the SDT under the process. On this basis, I find that Exelon has made its case that the SPM was not adhered to and that a change impacting applicability was made between the last successive and recirculation ballot.

**Recommended Actions and Options**

I refer the issue to the Standards Committee for handling. There are several options to consider:

1. Re-post the standard for a successive ballot and recirculation ballot. Essentially set the clock back and correctly replay the last steps of the process.
2. Ask the SDT to remove the clarification language from the final standard and go directly to recirculation ballot.
3. Ask the SDT to redesign the challenged portion of the proposed standard.

I recommend the Standards Committee pursue option 2.

Sincerely,



Herb Schrayshuen  
Vice President, Standards and Training

cc: Mr. Gerry. Cauley, President and CEO, NERC  
Mr. Ken Peterson, Chair, Board of Trustees Standards Oversight and Technology Committee  
Mr. David Cook, General Counsel, NERC  
Ms. Holly Hawkins, Associate General Counsel, NERC  
Mr. Michael Moon, Director Compliance Operations, NERC  
Ms. Laura Hussey, Manager Standards Process, NERC  
Ms. Mallory Huggins, GO/TO Standards Drafting Team Advisor, NERC  
Mr. Allen Mosher, Chair, Standards Committee  
Mr. Louis Slade, Chair, GO/TO Standards Drafting Team

**Attachments:**

- 1) Appeal Letter dated January 20, 2012 from Exelon
- 2) Exelon Response to Data/Information Request
- 3) Information Request 1 to NERC Standards Process Staff (plus response)
- 4) Information Request 1 to GO/TO Drafting Team Chair (plus response)

January 20, 2012

Mr. Herb Schrayshuen  
Vice President of Standards and Training  
North American Reliability Corporation  
3353 Peachtree Road, N.E.  
Suite 600, North Tower  
Atlanta, GA 30326

RE: Exelon Appeal of FAC-003-3 and FAC-003-X Process

Dear Herb:

Exelon wishes to initiate a Level 1 Appeal of the recent vote on FAC-003-3 (December 1, 2011 draft) and FAC-003-X (December 1, 2011 draft), Transmission Vegetation Management Program, as part of Project 2010-07, Generator Requirements at the Transmission Interface. Exelon believes that the NERC Standards Process Manual was not followed, and that based on the substantive changes made to both Standards following the Initial Ballot, NERC should have set the Standards for vote using a Successive Ballot rather than a Recirculation Ballot.

Exelon voted against these proposed Standards, and while we respect the vote of the Ballot Body, we believe that the manner in which the Standards were presented for vote is contrary to the process required by the NERC Standards Process Manual.

Prior to the Recirculation Ballot, Section 4.3.1, which defines the criteria for determining which Generation Owners will be covered by the Standards, was modified to increase the scope and applicability to generator owned overhead transmission lines by adding the words “or do not have a clear line of sight from the switchyard fence to the point of interconnection.” FAC-003-3; see also FAC-003-X.<sup>1</sup> The Standard Drafting Team’s (“SDT”) explanation for this last minute addition to Section 4.3.1 is that the addition of the “line of sight reference” merely clarifies the “exception language based on the intent that was agreed upon by the stakeholder body.” Sidebar comments to Sections 4.3.1 of FAC-003-3 and FAC-003-X. The SDT went on to identify the “intent” of the stakeholder body as follows:

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<sup>1</sup> The language in Section 4.3.1 of FAC-003-3 and FAC-003-X is similar, but not identical. (Compare Section 4.3.1 in FAC-003-3 (quoted in body of this letter) to FAC-003-X, which reads “or does not have a clear line of sight from the switchyard fence to the point of interconnection. . . .”) With respect to the language at issue in this appeal, the differences are of no consequence. Accordingly, references to Section 4.3.1 refer collectively to Section 4.3.1 of FAC-003-3 and FAC-003-X.

“We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor.’ With the addition of an explicit line of sight reference here, the SDT believes it has clarified its original intent.”<sup>2</sup>

This explanation does nothing more than (1) reiterate the point the SDT has maintained throughout the entire drafting process, namely that “the one mile length” of a transmission line “is a reasonable approximation of line of sight,” and (2) explain that the SDT included a “fixed starting point” (the fenced area of the generation station switchyard) from which to measure the line to address stakeholder concerns about excessive Generator Owner discretion and inconsistent application of the Standard. The stakeholder concerns and the SDT’s response have absolutely nothing to do with – and certainly do not express the “intent that has been agreed upon by the stakeholder body” – the inclusion of “or do not have a clear line of sight from the switchyard fence to the point of interconnection.” To be clear, the SDT, and even the Ad Hoc Group prior to the SDT, have always focused on the length of the transmission line (either a half mile as proposed by the Ad Hoc Group or a mile as proposed by the SDT) as the basis for determining coverage, the presumption being that up to a certain distance, the overhead line is in the line of sight at various locations throughout the Generator Owner’s property and reasonably subject to being managed through normal day-to-day plant activities. The SDT has not, until the most recent iteration of the Standards, focused on requiring a “clear” line of sight to “the point of interconnection.” The requirement that the Generator Owner be able to view the “point of interconnection” while standing at the switchyard fence is a wholly new requirement based on new considerations not previously addressed through stakeholder comments.

A review of the Technical Justification Document,<sup>3</sup> apparently developed prior to the Initial Ballot (referred to as the “Initial Technical Justification”) supports Exelon’s position. In that document, the SDT refers to the Ad Hoc Group’s original thought to exclude from the Standard any transmission lines that was “less than two spans [long] (generally one half mile from the generator property line).”<sup>4</sup> The SDT then explained that, “[a]fter reviewing formal comments, the SDT agreed to revise the exclusion so that it applies to a Facility [transmission line] if its length is ‘one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard’ to approximate line of sign [sic] from a fixed

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<sup>2</sup> Standard FAC-003-X at p. 2 (Draft 3: Dec. 1, 2011); Standard FAC-003-3 at p. 6 (Draft 3: Dec. 1, 2011)

<sup>3</sup> From the title, “Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface,” it appears that the document was created on September 30, 2011, although it appears that the PDF version was created on October 4, 2011. 2011\_09\_30\_Technical\_Justification\_Document.pdf. In either case, this means the document was codified prior to the start of the November 9, 2011 Initial Ballot.

<sup>4</sup> 2011\_09\_30\_Technical\_Justification\_Document.pdf at p. 3.

point,”<sup>5</sup> (the fixed point being the fenced area of the generating station switchyard). Importantly, the Ad Hoc Group and SDT focused on the length of the line, with no discussion or evaluation of requiring a “clear” line of sight from the fence “to the point of interconnection.”

Aside from the fact that the last minute change by the SDT does not reflect stakeholder intent, it is also technically unsupported. The SDT just added the requirement for a “clear” line of sight “to the point of interconnection” language without considering the implications of why such a change was required. While a specific fixed point may make sense for establishing a starting point from which to measure distance (the one-mile limitation), it does not when considering a clear line of sight, especially in light stakeholder comments and the SDT’s acknowledgment that

in many case, generation Facilities are either (1) **staffed and the overhead portion is within the line of sight** or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.<sup>6</sup>

Notably absent from this rationale is any requirement that there be a clear line of sight from a fixed point; nor is a clear line of sight required when the distance of the overhead line is short (less than a mile) and the Facilities are staffed on a daily basis, meaning that the overhead line will be subject to observation by staff, even if the staff does not have a clear line of sight from a specified fixed point (the switchyard fence) to the point of interconnection. An example helps illustrate this point. Some Generator Owner transmission lines come out of the generating station and take a ‘dog leg’ turn (the line turns at one of the towers). Standing at the tower, an individual has a clear line of sight to either end of the line (the end coming out of the station and the end connecting with the point of interconnection). Since the generating Facility is staffed and the line is within the Generator Owner’s property line or controlled area, the line can be observed and maintained by staff in the same manner as any other short distance line with a “clear” line of sight from the switchyard fence to the point of interconnection.

As illustrated by the preceding discussion, the SDT’s last minute addition of “or do not have a clear line of sight from the switchyard fence to the point of interconnection” constitutes a material and significant change in the scope of the applicability of the Standards to Generator Owners, and it was inappropriate for NERC to use a Recirculation Ballot. The Standard Process Manual regarding Recirculation Ballots (pages 19-20) states:

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<sup>5</sup> 2011\_09\_30\_Technical\_Justification\_Document.pdf at p. 3.

<sup>6</sup> Consideration of Comments Generator Requirements at the Transmission Interface Project 2010-07, p. 1 (emphasis added).

## **Conduct Recirculation (Final) Ballot (Standard has not Changed Substantively from Prior Ballot)**

When the drafting team has reached a point where it has made a good faith effort at resolving applicable objections, the team shall conduct a recirculation ballot. In the recirculation ballot, members of the ballot pool shall again be presented the proposed standard **(that has not been significantly changed from the previous ballot)** along with the reasons for negative votes, the responses, and any resolution of the differences. **An insignificant revision is a revision that does not change the scope, applicability, or intent of any requirement and includes but is not limited to things such as correcting the numbering of a requirement, correcting the spelling of a word, adding an obviously missing word, or rephrasing a requirement for improved clarity.** Where there is a question as to whether a proposed modification is “substantive” the Standards Committee shall make the final determination. There is no formal comment period concurrent with the recirculation ballot and no obligation for the drafting team to respond to any comments submitted during the recirculation ballot.

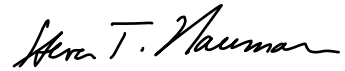
(Emphasis added.)

Regardless of whether the SDT believed that its addition of the language at issue here clarified the intent of the stakeholder body, using the Recirculation Ballot for the Standards was not warranted or allowed by process. An unarticulated intent of the stakeholder body cannot serve as the basis for a substantive change to the Standard. More importantly, the language added by the SDT clearly changed the scope and applicability of the Standard, by drawing in Generator Owners that would have otherwise been excluded from the Standards, namely those Generator Owners with transmission lines less than a mile long that will now be covered by the Standard because some shorter distance of its line is not clearly visible from the switchyard fence to the point of interconnection. The SDT's presentment of this change through a Recirculation Ballot deprived Exelon (and possibly others) of having its comments considered by the SDT and the SDT answer on the record for consideration by the Ballot Body in accordance with the requirements of a Successive Ballot. You can read Exelon's comments on the Recirculation Ballot at:

<https://standards.nerc.net/VoterComment.aspx?VoteGUID=8801b661-a474-4f54-b14a-4cfe644bdaa6>.

Please let me know if you have any further questions.

Best regards,

A handwritten signature in black ink that reads "Steven T. Naumann". The signature is written in a cursive style with a prominent initial "S" and a long, sweeping underline.

Steven T. Naumann  
Vice President, Wholesale Market Development  
Federal Regulatory Affairs & Public Policy, Exelon Corporation

4300 Winfield Road  
Warrenville, Illinois 60555  
[Tamra.Domeyer@exeloncorp.com](mailto:Tamra.Domeyer@exeloncorp.com)  
(630) 657-3753

**Via email [herb.schrayshuen@nerc.net]**

February 3, 2012

Mr. Herb Schrayshuen  
Vice President of Standards and Training  
North American Reliability Corporation  
3353 Peachtree Road, N.E.  
Suite 600, North Tower  
Atlanta, GA 30326

**Re: Exelon Corporation Response to Data/Information Request  
Exelon Level 1 Appeal of FAC-003-3/X in Project 2010-07**

Dear Mr. Schrayshuen:

As requested, enclosed is the Exelon Corporation Response to Data/Information Request in support of Exelon's Level 1 Appeal of FAC-003-3/X in Project 2010-07.

If you require additional information or you have any questions, please let me know.

Very truly yours,



Tamra Domeyer  
Assistant General Counsel

Encl.

cc: Steven T. Naumann



Data/Information Request  
Exelon Level 1 Appeal of FAC-003-3/X in Project 2010-07

**RESPONSE OF EXELON COPORATION TO DATA/INFORMATION REQUEST**

**Summary of Appeal:** Please refer to Exelon’s January 20, 2012 letter addressed to Herb Schrayshuen, Vice President of Standards and Training, for a more detailed discussion of the basis for Exelon’s Level 1 Appeal of the FAC-003-3/X<sup>1</sup> Recirculation Ballot vote. Specifically, Exelon takes issue with the results of the Recirculation Ballot for FAC-003-3/X and acceptance of the vote. The Standard Drafting Team’s (“SDT”) last minute addition of language to Section 4.3.1 (“or do not have a clear line of sight from the switchyard fence to the point of interconnection”<sup>2</sup> (referred to as the “clear line of sight” language)) that significantly broadens the scope of applicability to Generation Owners necessitated submission of the revised Standards for comment and a Successive Ballot. Exelon maintains further that the SDT’s revision to Section 4.3.1 constitutes a substantive and material change to the scope, applicability, and intent of the requirement that adversely impacts Exelon.

**Request 1:** When and through what means did Exelon representative(s) first become aware of the modifications (line of sight language) to the FAC-003-3/X standard which they believe were substantive?

**Response to Request 1:** Exelon first became aware of and focused on the SDT’s substantive modification to Section 4.3.1 of FAC-003-3/X on December 20, 2011,<sup>3</sup> when its subject matter experts held an internal conference call to review and discuss the Recirculation Ballot for FAC-003-3/X. During that review, Exelon’s subject matter experts were surprised to discover what they determined to be a substantive modification to Section 4.3.1, since the Standards Announcement for the Initial Ballot results clearly committed to post any substantive changes “for a parallel 30-day comment period and successive ballot.”<sup>4</sup>

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<sup>1</sup> References to FAC-003-3/X are to FAC-003-3 (Draft 3, December 1, 2011) and FAC-003-X (Draft 3, December 1, 2011), specifically Section 4.3.1 of each draft Standard. The language in Section 4.3.1 of each Standard is similar, but not identical. With respect to the language at issue in this appeal, the slight differences in language in Section 4.3.1 of each draft Standard are of no consequence.

<sup>2</sup> FAC-003-3; Section 4.3.1 of FAC-003-X reads as follows: “or does not have a clear line of sight from the switchyard fence to the point of interconnection. . . .”

<sup>3</sup> NERC issued a Standards Announcement of the Recirculation Ballot on December 14, 2011. Although Exelon received the Standards Announcement, it did not identify the substantive modification to Section 4.3.1 until the internal conference call on December 20, 2011.

<sup>4</sup> Standards Announcement, Project 2010-07 Generator Requirements at the Transmission Interface, Initial Ballot Results, p. 1.

Exelon recognized that the proposed modification to FAC-003-3/X would have no impact on Exelon unless the Standard(s) received the requisite votes for approval through the Recirculation Ballot. On December 21, 2011, Exelon advised PJM and the Midwest ISO of Exelon's determination that the SDT's modification of FAC-003-3/X was not minor, changed the scope of applicability, and should be submitted through a Successive Ballot. Exelon also challenged the technical basis (lack thereof) for the SDT's last minute addition of the "clear line of sight" language to Section 4.3.1 and advised PJM and Midwest ISO of its intention to vote "negative" in the Recirculation Ballot. Exelon invited PJM and Midwest ISO to forward Exelon's comments to various PJM and Midwest ISO members. On the same day (December 21), Exelon received a response from Louis Slade, writing "[a]s Vice Chair of the SDT," expressing his disappointment with Exelon's decision to vote negative and disagreement with Exelon's position. (See Attachment 1, email from Exelon, sent on December 21, 2011 at 9:34 a.m., and response of SDT Vice Chair sent on December 21, 2011 at 2:42 p.m.) The Vice Chair of the SDT subsequently requested that PJM distribute his response to PJM members. Neither the SDT nor NERC took any action to remove FAC-003-3/X from the Recirculation Ballot and submit it for comments and a Successive Ballot.

Exelon collectively<sup>5</sup> voted "Negative" in the Recirculation Ballot(s) for FAC-003-3/X. In its comments in support of its negative vote, Exelon noted, among other things, that the modification constituted a substantive change that should have been presented through a Successive Ballot. The Recirculation Ballot closed on December 23, 2011. On January 3, 2012, NERC issued a Standards Announcement with the Recirculation Ballot Results, including the approval of Standard FAC-003-3/X. With that announcement, and in the absence of an appeal, NERC conclusively foreclosed consideration of Exelon's comments and shut the door on an opportunity for a Successive Ballot for FAC-003-3/X. On January 17, 2012, Steven T. Naumann, Vice President, Wholesale Market Development for Exelon, discussed this matter with Herb Schrayshuen, NERC's Vice President of Standards and Training. On January 18, Mr. Naumann sent an e-mail to Mr. Schrayshuen informing him that Exelon would be filing a level 1 appeal and that the formal appeal would be sent by the close of business on January 20. (See Attachment 2). Exelon subsequently submitted its Level 1 Appeal on January 20, 2012, within thirty days of the close of the Recirculation Ballot on December 23, 2011 and the January 3, 2012 announcement of the Recirculation Ballot results.

**Respondent Identity:** Tamra Domeyer, Assistant General Counsel, Exelon Business Services Company

**Date:** February 3, 2012

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<sup>5</sup> Exelon voting ballot body members for the (12/14/2011 – 12/23/11) Recirculation Ballots of Project 2010-07 for FAC-003-3 and FAC-003-X were PECO Energy, ComEd, Exelon Nuclear, and Exelon Power Team.

**Request 2:** Specifically identify the “direct material” or adverse impact the change made to FAC-003-3/X between the successive and recirculation ballot has on Exelon?

**Response to Request 2:** The last minute modification to Section 4.3.1 has a material, adverse impact on Exelon by changing the scope and applicability of the Standard. Specifically, of the seventeen active nuclear generating units at ten different sites owned and operated by Exelon affiliate Exelon Generation Company, LLC – Exelon Nuclear, *none* satisfied the applicability criteria under earlier versions of FAC-003-3/X,<sup>6</sup> and as such, *none* of Exelon’s nuclear generating units would have been subject to the FAC-003-3/X requirements. The last minute addition of the “clear line of sight” language to the FAC-003-3/X Standards that were approved in the December 23, 2011 Recirculation Ballot changes Exelon Nuclear’s status from a Generator Owner for which the Standards are “not applicable” to a Generator Owner for which the Standards are potentially “applicable.” Exelon Nuclear has not finished its investigation at each of its ten sites to conclusively determine which of its seventeen generating units might now be subject to the FAC-003-3/X requirements. The point is that by adding the “clear line of sight” requirement, the SDT has now removed Exelon Nuclear from the group of Generator Owners not subject to FAC-003-3/X requirements and placed it squarely in a group potentially subject to the requirements of FAC-003-3/X.

A determination that the current FAC-003-3/X Standards may now be applicable to even one of Exelon Nuclear’s generating units has a material, adverse impact on Exelon Nuclear. Vegetation management programs developed to implement NERC Standard FAC-003 are expensive and time consuming and require specialized skills. In addition, compliance with each NERC Standard requires substantial resources, time, and attention. While Exelon certainly supports and understands the need for reliability standards and complies with all NERC Reliability Standards

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<sup>6</sup> FAC-003-3/X was submitted for vote on two occasions: as an Initial Ballot from November 9 through November 18, 2011 and as a Recirculation Ballot from December 14 through December 23, 2011. The version of FAC-003-3/X (Draft 2) submitted to the Initial Ballot defined Generation Facilities that would be subject to FAC-003 requirements as “Overhead transmission lines that extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating switchyard . . . .” (FAC-003-3 (Draft 2, September 29, 2011); FAC-003-X (Draft 2, August 31, 2011) (“Generator Owner that owns an overhead transmission line(s) that extends greater than one mile or 1.609 kilometers beyond the fenced areas of the generating station switchyard up to the point of interconnection with the Transmission Owner’s Facility. . . .” (Section 4.3.1)) Earlier versions of the FAC-003-3/X Standard contained similar verbiage focusing solely on the length of the transmission line as the trigger for determining whether a Generator Owner would be subject to the FAC-003-3/X (Draft 2) requirements. The generator lines that Exelon Nuclear owns are *less than a half mile long* for each nuclear generating unit, and thus, FAC-003-3/X (Draft 2) requirements would not have applied to any of Exelon Nuclear’s generating units.

applicable to it regardless of the cost, the public policy concerns that warrant application of a NERC Standard to a specific registered entity – namely reliability of the bulk electric system – simply do not exist here. As the SDT aptly noted, “the transmission elements and facilities owned and operated by Generator Owners are most often not part of the integrated grid” and

as such have little, if any, measurable effect on the overall reliability of the BES. In fact, registering a Generator Owner or Generator Operator as a Transmission Owner or Transmission Operator may decrease reliability by diverting the Generator Owner’s or Generator Operator’s attention from the operation of the equipment that actually produces electricity – the generation equipment itself.<sup>7</sup>

The same can be said here – requiring Exelon Nuclear to implement and maintain a formal NERC vegetation management program for short distances of lines (each of Exelon Nuclear’s generator lines is *less than a half mile long*) that are within Exelon Nuclear’s controlled property, in the clear line of sight from various locations throughout its property, and reasonably subject to being managed through normal day-to-day plant activities and surveillances conducted by any number of its employees staffed to operate the plant round the clock each and every day,<sup>8</sup> adds little to no value to the reliability of the bulk electric system and is not a good use of the resources of the Generation Owner/Operator, the Regional Entity or the ERO.

Exelon’s position is entirely consistent with the SDT’s findings that:

in many cases, generation Facilities are either (1) **staffed and the overhead portion is within line of sight** or (2) **the overhead Facility is over a paved surface**. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.<sup>9</sup>

Many of Exelon Nuclear’s generator transmission lines travel over paved surfaces, with no vegetation at all on the ground under the lines. Nevertheless, if the “clear line of sight” requirement stands, Exelon Nuclear will be required to assess whether it has a “clear line of sight *from the switchyard fence to the point of interconnection.*” Aside from the fact that the meaning

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<sup>7</sup> Project 2010-07: Generator Requirements at the Transmission Interface, Background Resource Document, pp. 2, 3.

<sup>8</sup> All operating nuclear generating units are staffed continuously and must maintain minimum staffing in accordance with site specific licensing requirements of the Nuclear Regulatory Commission.

<sup>9</sup> Consideration of Comments, Generator Requirements at the Transmission Interface, Project 2010-07, p. 1 (emphasis added).

of “switchyard fence” is unclear,<sup>10</sup> there is no basis for requiring a clear line of sight from the switchyard fence to the point of interconnection. The premise of the SDT in focusing on the length of the generator transmission line has always been that the relatively short length of the line (up to a mile) constitutes a proxy for the line of sight, since the area traversed by the line is relatively short, allowing the Generator Owner to have a line of sight from any number of vantage points within the Generator Owner’s controlled area and property. Moreover, to the extent the entire length of the line travels over paved surfaces or structures, any barriers or obstacles to a clear line of sight will not be caused by vegetation, as discussed in FAC-003-3/X but, rather, by equipment, components, or structures. Clearance between generator lines and structures is already covered in other NERC Standards and is the subject of a recently issued NERC Alert.<sup>11</sup> And, even for those lines that do travel over areas of vegetation, the regular monitoring and surveillance by Exelon Nuclear staff of the areas over which the lines travel provides reasonable assurance of protection from vegetation related events.

Referring to the example noted in Exelon’s January 20, 2011 Level 1 Appeal letter, at another Exelon Nuclear location, a transmission line coming out of the generating station takes a “dog leg” turn (the line turns at one of the towers). Standing at the tower, an individual has a clear line of sight to either end of the line (the end coming out of the station and the end connecting with the point of interconnection). Since the generating Facility is staffed and the line is within Exelon Nuclear’s property and controlled area, the line can be observed and maintained by Exelon Nuclear’s round the clock staff in the same manner as any other short distance line with a “clear line of sight from the switchyard fence to the point of interconnection.”

**Respondent Identity:** Tamra Domeyer, Assistant General Counsel, Exelon Business Services Company

**Date:** February 3, 2012

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<sup>10</sup> Does switchyard fence mean the “generating switchyard” fence, as referenced in the beginning of the first sentence in Section 4.3.1 (“overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard”) or the Transmission Owner switchyard fence that surrounds the switchyard where the generation transmission line interconnects with the transmission system? Exelon Nuclear’s generating stations do not have generating switchyards; if “switchyard fence” refers to the generating switchyard, there is no fence from which Exelon Nuclear can determine whether it has a “clear line of sight.”

<sup>11</sup> FAC-008, FAC-009, and NERC Alert R-2010-10-07-01, Consideration of Actual Field Conditions in Determination of Facility Ratings.

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**From:** pjm-rsacs-bounces+alison.mackellar=exeloncorp.com@lists.pjm.com [mailto:pjm-rsacs-bounces+alison.mackellar=exeloncorp.com@lists.pjm.com] **On Behalf Of** brownp@pjm.com  
**Sent:** Thursday, December 22, 2011 8:01 AM  
**To:** pjm-rsacs@lists.pjm.com  
**Subject:** [Pjm-rsacs] FW: FW: REVIEW Project 2010-07 Generator Requirements at the Transmission Interface - Negative Voting Position

The SDT's response to Exelon's comments, for your consideration.

Patrick Brown  
Manager, NERC and Regional Coordination  
PJM Interconnection  
Phone: 610-666-4597  
Cell: 610-908-9262  
[brownp@pjm.com](mailto:brownp@pjm.com)

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**From:** Louis Slade [mailto:louis.slade@dom.com]  
**Sent:** Thursday, December 22, 2011 8:56 AM  
**To:** Brown, Patrick  
**Subject:** RE: [Pjm-rsacs] FW: REVIEW Project 2010-07 Generator Requirements at the Transmission Interface - Negative Voting Position

Would you consider also distributing this?

**From:** Louis Slade (Services - 6)  
**Sent:** Wednesday, December 21, 2011 2:42 PM  
**To:** 'john.bee@exeloncorp.com'  
**Subject:** FW: REVIEW Project 2010-07 Generator Requirements at the Transmission Interface - Exelon Comments

Dear Mr. Bee,

As Vice Chair of the SDT, I am writing to express my personal disappointment that Exelon plans to change its vote. The team has worked very hard to strike a reasonable balance in applying additional reliability standards to GO/GOPs who own or operate all, or a portion of, a sole use facility used to interconnect generators to the integrated transmission system. Throughout our efforts, we have continually cited the need to apply FAC-003 to such a facility while trying to 'carve out' those that didn't represent a risk to the reliability of the integrated transmission system. We reasoned that exempting lines of short length at generating facilities was justified because they would likely be located within sight of the personnel at that generating facility.

The Background Resource paper from our 1<sup>st</sup> posting stated "Revise FAC-003 so that it applies to Generator Owners that own a Facility that extends greater than one half mile beyond the fenced area of the switchyard, generating station or generating substation (up to the point of interconnection with the Transmission system). (See accompanying draft standards FAC-003-X and FAC-003-3.)

Attachment 1

o The drafting team elected to use the half-mile qualifier in its latest proposed changes. The GOTO Ad Hoc Group had originally proposed something similar, but their proposed criterion was a length of “two spans (generally one half mile from the generator property line).” The drafting team elected to use only the half-mile qualifier because it has been supported by industry comment and is clearer than referencing both two spans and the half-mile length. **This distance is within the Generator Owner’s line of sight and could be visually monitored for vegetation conditions on a routine basis.** Beyond the distance of one half mile, a vegetation management program is necessary to manage the Right-of-Way.”

The SDT received comments during this posting that the requirements allowed the GO to determine where to begin measuring the length of its facility from either; (a) the fenced area of the switchyard (b) the generating station or (c) the generating substation. As the SDT discussed these comments we agreed that this was not our intent and agreed that a more clearly defined beginning point for the measurement was desired. We made subsequent changes to the next drafts posted for comments.

Again, we explained our rationale in the Technical Justification document posted, stating “After reviewing formal comments, the SDT agreed to revise the exclusion so that it applies to a Facility if its length is “one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard” **to approximate line of sign from a fixed point.** Other than revising this exclusion, the SDT applied the same criteria to the Generator Owner as applies to the Transmission Owner.....”

The SDT received many comments during the next posting stating that it did not provide technical justification for the exemption. Given that we have cited line of sight in our reference documents and in our responses, the only solution we found reasonable was to include it in the actual language of the reliability standard itself.

As we stated in the Technical Justification document posted with our most recent changes “ The SDT and most stakeholders agree with the Ad Hoc Group recommendation that FAC-003 be applicable to Generator Owners that own a generation interconnection Facility if that Facility contains overhead conductors. The Ad Hoc Group originally excluded such a Facility from this requirement if its length is less than two spans (generally one half mile from the generator property line). The SDT agrees with that intended exclusion in principle; as it discusses in the document titled “Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface,” **the SDT recognizes that in many cases, generation Facilities are (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface.** Stakeholders have generally supported the rationale for exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit.”

While I respect and value your opinion, it is my belief the SDT has done the best it can to include language that allows for an exemption while insuring that risk to the integrated transmission system is minimized. Due to the virtually unlimited configurations, topologies, etc. of these facilities, it is impossible to create a clear and unambiguous standard that will accommodate each facility to the owners satisfaction or, for that matter, to that facility’s specific potential to adversely impact reliability of the integrated transmission system.

The SDT has chosen language that it believes has the best chance of meeting the stated purpose of the FAC-003 standard, being measurable to both the registered entity and the auditor and reducing compliance burden without a commensurate improvement in reliability.

These comments are my own and are not to be taken as those of either the SDT members nor my employer.

Sincerely,

Louis Slade, Jr.

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**From:** pjm-rsacs-bounces+louis.slade=dom.com@lists.pjm.com [mailto:pjm-rsacs-bounces+louis.slade=dom.com@lists.pjm.com] **On Behalf Of** brownp@pjm.com  
**Sent:** Thursday, December 22, 2011 8:51 AM  
**To:** pjm-rsacs@lists.pjm.com  
**Subject:** [Pjm-rsacs] FW: REVIEW Project 2010-07 Generator Requirements at the Transmission Interface - Negative Voting Position  
**Importance:** High

FYI- some comments from Exelon regarding the changes made to Project 2010-07 prior to the recirc ballot.

Patrick Brown  
Manager, NERC and Regional Coordination  
PJM Interconnection  
Phone: 610-666-4597  
Cell: 610-908-9262  
[brownp@pjm.com](mailto:brownp@pjm.com)

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**From:** john.bee@exeloncorp.com [mailto:john.bee@exeloncorp.com]  
**Sent:** Wednesday, December 21, 2011 9:34 AM  
**To:** MKnox@midwestiso.org; Brown, Patrick  
**Subject:** REVIEW Project 2010-07 Generator Requirements at the Transmission Interface - Negative Voting Position  
**Importance:** High

Marie and Patrick,  
Yesterday SMEs from the Exelon companies review the proposed changes to Project 2010-07 Generator Requirements at the Transmission Interface related to the recirculation ballot. We noticed what we consider a significant change to FAC-003-3 Requirement with the addition of the text bolded and underlined below:

**4.3.1. Generator Owner that owns an overhead transmission line(s) that extends greater than one mile or (1.609 kilometers) beyond the fenced area of the generating station switchyard up to the point of interconnection with a Transmission Owner's Facility or does not have a clear line of sight from the switchyard fence to the point of interconnection and**



is operated at 200 kV and above, and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.

Exelon plans to change its affirmative voting position to negative based on the additional text. First we don't feel this was a minor change and feel that that the ballot should have been a successive ballot not a recirculation ballots. Second we feel the additional text is ambiguous adds unnecessary restrictions in assessing criteria applicability. Exelon feels that the SDT has not provided adequate technical justification as to why a single line of sight (linearly from the switchyard fence to the point of the interconnection) is the only acceptable vantage point from which to verify the condition of a generator interconnection. We are currently working on comments to be submitted with our negative ballot and plan to be completed by 12:00 today. Because of the upcoming holidays and the fact that the ballot pool will close on 12/23, I am attaching our working draft comments. Please feel free to pass this on to members of your PJM RSACS and the MISO Standards Collaboration members if you see fit.

Happy Holidays,

*John Bee*

Exelon Transmission Strategy & Compliance

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**Domeyer, Tamra:(GenCo)**

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**From:** Naumann, Steven T.:(BSC)  
**Sent:** Wednesday, January 18, 2012 12:10 PM  
**To:** 'herb.schrayshuen@nerc.net'  
**Cc:** Domeyer, Tamra:(GenCo)  
**Subject:** Appeal of Project 2010-

Herb:

To follow up on our discussion yesterday, Exelon intends to file a formal Level 1 Appeal of FAC-003-3/FAC-003-X balloted as part of Project 2010-7. We will send you the formal appeal by close of business on Friday, January 20. Thanks for discussing this issue with me and please let me know if you need further information.

Steve

Steven T. Naumann  
Vice President Wholesale Market Development  
Federal Regulatory Affairs & Public Policy, Exelon Corporation  
Phone: 312.394.2807  
FAX: 312.394.8997  
Mobile: 708.404.6829  
E-Mail: [steven.naumann@exeloncorp.com](mailto:steven.naumann@exeloncorp.com)

Attachment 2

Data/Information Request  
Exelon Level 1 Appeal of FAC-003-3x in Project 2010-07

**Request 1**—Identify in which steps of the standards development process, and provide evidence to support, that Exelon Comments were made visible to the other industry participants in the FAC-003-x ballot.

**Response 1:**

The attached document summarizes the process steps taken in developing FAC-003-X and FAC-003-3 and the comments pertaining to FAC-003 submitted by Exelon at each step. Each time comments are collected in a formal or informal comment period, a “Comments Received” document is posted to the project webpage within a few business days of the comment period closing. In addition, the comments are posted, along with the drafting team’s response to the comments (in summary form for informal comment periods and in detail for formal comment periods) before the next process step is initiated. A full record of all postings is available on the project [webpage](#).

Respondent Identity: Laura Hussey, Standards Process Manager

Date: 1/26/2012

**Request 2-**Identify the participants and the meeting or calls during which the decision that the standards changes (regarding line of sight) referenced in Exelon's complaint were not substantive. Provide any contemporaneous documents generated from the meeting or call.

**Response 2:**

The decision to allow FAC-003 to proceed to recirculation ballot was carefully considered by NERC Standards Process staff (Laura Hussey, Maureen Long) in consultation with the drafting team coordinator (Mallory Huggins) and leadership (Louis Slade and Scott Helyer). There were no conference calls or face-to-face meetings (none of the above-mentioned are collocated, and one member of the drafting team leadership was on vacation during the decision so was only available remotely).

A complete record of the emails exchanged is attached.

Respondent Identity: Laura Hussey, Standards Process Manager

Date: 1/26/2012

Data/Information Request  
Exelon Level 1 Appeal of FAC-003-3x in Project 2010-07

Request 1 – Outline the basis upon which the industry participants in the Standards Drafting Team concluded that the changes Exelon complains about in its Level 1 appeal were not substantive.

Response 1 –The SDT agreed that, based upon stakeholder comments received and recommendations from FERC staff observers, it should better define exemption for Generator Owners in Applicability Section 4.3.1. The goal was to ensure that the explicit language of the exemption included the clear line of sight justification for exempting “qualifying” lines from applicability. To support its changes, the SDT then reviewed its past work, as well as that of the Ad Hoc Team. It justified its changes between the successive ballot and the recirculation ballot based on the following:

[Ad Hoc Report](#) – P. 15 of the report states “The rationale for the selection of the two-span criteria is that this distance is in the generator operator’s line-of-sight and as such could be visually monitored for vegetation conditions on a routine basis, and beyond which distance a vegetation management program would be necessary for the Right-of-Way” (emphasis added).

Documents produced by the Project 2010-07 SDT and posted during stakeholder comment periods

- The [background resource document](#) (white paper), posted with the revised versions of FAC-003 for comment in June 2011, states: “The drafting team elected to use only the half-mile qualifier because it has been supported by industry comment and is clearer than referencing both two spans and the half-mile length. This distance is within the Generator Owner’s line of sight and could be visually monitored for vegetation conditions on a routine basis. Beyond the distance of one half mile, a vegetation management program is necessary to manage the Right-of-Way” (emphasis added).
- The [technical justification document](#), which was posted with the revised versions of FAC-003 for comment in October 2011, states: “After reviewing formal comments, the SDT agreed to revise the exclusion so that it applies to a Facility if its length is “one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard” to approximate line of sign from a fixed point” (emphasis added).

Based upon these documents, the SDT believes the technical justification for the exemption has existed from the beginning of this effort. The intent – that the exemption be for generator interconnection Facilities within the generator’s line of sight – has been communicated clearly all along, but until the change between the successive ballot and the recirculation ballot, that intent was implicit rather than explicit. After extensive discussion, the SDT agreed with some comments and with the recommendations of FERC staff observers that it would be better if the line of sight language was included in the standard itself rather than only in supporting documentation. For this reason, the SDT modified the language in Applicability Section 4.3.1 of both versions of FAC-003 and considered the change clarifying – and thus non-substantive – based on its communications of its intent throughout the standard development process. At this point, the SDT passed the standards along to NERC staff for a final determination of whether the proposed FAC-003 changes were appropriate for recirculation ballot.

It is also worth noting that during the recirculation ballot in December 2011, Exelon raised its concern via email to PJM and MISO listservs. SDT Chair Louis Slade was afforded the opportunity to respond to this concern for the benefit of all those on the distribution lists, and the high approval ratings on FAC-003-3 and FAC-003-X (85.38% and 85.03%, respectively) indicate that other entities found Louis's explanation of the non-substantive nature of the FAC-003 changes satisfactory.

Respondent Identity: Louis S. Slade, Jr.

Date: Jan. 26, 2012

Request 2 – Identify the participants and the meeting or calls during which the decision that the standards changes (regarding line of sight) referenced in Exelon’s complaint were not substantive. Provide any contemporaneous documents generated from the meeting or call.

Response 2 – As identified in the meeting notes from the November 30-December 1, 2011 SDT meeting in Washington, DC ([posted on NERC’s website](#)), participants during the original discussion were: SDT members Louis Slade, Scott Helyer, Sam Dwyer, Steve Enyeart, Bob Goss, and Rick Terrill; observers Ellen Oswald and John Seelke; FERC staff Susan Morris and Stephanie Schmidt; and NERC staff Mallory Huggins. Later email discussions included the full SDT, with major participation from Louis Slade and Sam Dwyer, as indicated in the attached emails.

Respondent Identity: Louis Slade

Date: Jan. 26, 2012

**From:** [Mallory Huggins](#)  
**To:** [grti\\_sdt](#)  
**Subject:** FAC-003 Exception Language  
**Date:** Tuesday, December 13, 2011 3:38:34 PM  
**Attachments:** [FAC-003-3\\_redline\\_to\\_last\\_posted.doc](#)

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Hi everyone,

There's some concern that the exception language in FAC-003 may be perceived as changing the scope of the previous changes, which would mean the standard couldn't go to recirculation ballot and would have to be posted for comment again. I think we have some solid background to justify that it is just a clarifying change, because in a previous comment report we talked about line of sight being the goal – and now we are simply clarifying that. I'm working on some language that makes this clear for the comment report/technical justification document, but alongside that, we need to see if we can format the language change we've proposed in the standard a way that's a little more concise.

I've attached what we have now. Any ideas? Ideally, we'd make this change this afternoon so we can post for ballot tomorrow, but we also have the option of holding off until the first week of January...

Thanks,  
Mallory

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**Mallory Huggins**  
**Standards Specialist**  
**North American Electric Reliability Corporation**  
**1120 G Street NW, Suite 990, Washington, DC 20005**  
**(p): 202-383-2639 | (c): 609-619-1629 | (f): 202-393-3955**

---

Y



**From:** [Louis Slade](mailto:Louis.Slade@dom.com)  
**To:** [Mallory Huggins](mailto:Mallory.Huggins@nerc.net); "[SDwyerIV@ameren.com](mailto:SDwyerIV@ameren.com)"  
**Cc:** "[SHelyer@tnsk.com](mailto:SHelyer@tnsk.com)"  
**Subject:** Re: FAC-003 Exception Language  
**Date:** Tuesday, December 13, 2011 5:53:26 PM

---

Ok by me

---

**From:** Mallory Huggins [mailto:[Mallory.Huggins@nerc.net](mailto:Mallory.Huggins@nerc.net)]  
**Sent:** Tuesday, December 13, 2011 05:49 PM  
**To:** Louis Slade (Services - 6); '[SDwyerIV@ameren.com](mailto:SDwyerIV@ameren.com)' <[SDwyerIV@ameren.com](mailto:SDwyerIV@ameren.com)>  
**Cc:** '[SHelyer@tnsk.com](mailto:SHelyer@tnsk.com)' <[SHelyer@tnsk.com](mailto:SHelyer@tnsk.com)>  
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**Sent:** Tuesday, December 13, 2011 5:47 PM  
**To:** '[SDwyerIV@ameren.com](mailto:SDwyerIV@ameren.com)'; Mallory Huggins  
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**Sent:** Tuesday, December 13, 2011 5:04 PM  
**To:** Mallory Huggins  
**Cc:** scott Helyer (shelyer@tnsk.com); Louis Slade (louis.slade@dom.com)  
**Subject:** RE: FAC-003 Exception Language

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**From:** Mallory Huggins [mailto:Mallory.Huggins@nerc.net]  
**Sent:** Tuesday, December 13, 2011 2:38 PM  
**To:** grti\_sdt  
**Subject:** FAC-003 Exception Language

Hi everyone,

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I've attached what we have now. Any ideas? Ideally, we'd make this change this afternoon so we can post for ballot tomorrow, but we also have the option of holding off until the first week of January...

Thanks,  
Mallory

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**Mallory Huggins**  
**Standards Specialist**  
**North American Electric Reliability Corporation**

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(p): 202-383-2639 | (c): 609-619-1629 | (f): 202-393-3955

---  
Y

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**From:** [Dwyer IV, Samuel J](#)  
**To:** [Mallory Huggins](#)  
**Cc:** [scott Helyer \(shelyer@tnsk.com\)](#); [Louis Slade \(louis.slade@dom.com\)](#)  
**Subject:** RE: FAC-003 Exception Language  
**Date:** Tuesday, December 13, 2011 5:27:05 PM

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**Sent:** Tuesday, December 13, 2011 5:04 PM  
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**Cc:** ["SHelyer@tnsk.com"](mailto:SHelyer@tnsk.com)  
**Subject:** RE: FAC-003 Exception Language  
**Date:** Tuesday, December 13, 2011 5:49:00 PM

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**Sent:** Tuesday, December 13, 2011 5:47 PM  
**To:** 'SDwyerIV@ameren.com'; Mallory Huggins  
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**Cc:** ["SHelyer@tnsk.com"](mailto:SHelyer@tnsk.com)  
**Subject:** Re: FAC-003 Exception Language  
**Date:** Tuesday, December 13, 2011 6:42:44 PM

---

Agree that we want to go to recirc. So don't make changes that prohibit doing so

---

**From:** Dwyer IV, Samuel J [mailto:SDwyerIV@ameren.com]  
**Sent:** Tuesday, December 13, 2011 06:31 PM  
**To:** Louis Slade (Services - 6); 'Mallory.Huggins@nerc.net' <Mallory.Huggins@nerc.net>  
**Cc:** 'SHelyer@tnsk.com' <SHelyer@tnsk.com>  
**Subject:** RE: FAC-003 Exception Language

Louis –

We did, so either is fine with me.

Mallory – you might want to try Louis' simpler words below first. If that doesn't fly, try the switchyard wording if that's what we need to put this out for recirc.

Louis – Is that OK with you? I'd hate to see us lose our momentum at the last minute and I don't think this is a deal-breaker – at least in my opinion.

Sam

**Sam Dwyer** :: Consulting Engineer, POS QMS :: T 314.957.3463  
**Ameren Missouri** :: 3701 S Lindbergh Suite 204 :: St. Louis, MO 63127

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**To:** Dwyer IV, Samuel J; 'Mallory.Huggins@nerc.net'  
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**Cc:** ["SHelyer@tnsk.com"](mailto:SHelyer@tnsk.com)  
**Subject:** RE: FAC-003 Exception Language  
**Date:** Tuesday, December 13, 2011 6:31:31 PM

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Louis –

We did, so either is fine with me.

Mallory – you might want to try Louis' simpler words below first. If that doesn't fly, try the switchyard wording if that's what we need to put this out for recirc.

Louis – Is that OK with you? I'd hate to see us lose our momentum at the last minute and I don't think this is a deal-breaker – at least in my opinion.

Sam

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**From:** [Louis Slade](mailto:Louis.Slade@ameren.com)  
**To:** ["SDwyerIV@ameren.com"](mailto:SDwyerIV@ameren.com); [Mallory Huggins](mailto:Mallory.Huggins@nerc.net)  
**Cc:** ["SHelyer@tnsk.com"](mailto:SHelyer@tnsk.com)  
**Subject:** Re: FAC-003 Exception Language  
**Date:** Tuesday, December 13, 2011 5:47:15 PM

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**Sent:** Tuesday, December 13, 2011 05:41 PM  
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**Cc:** scott Helyer (shelyer@tnsk.com) <shelyer@tnsk.com>; Louis Slade (Services - 6)  
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**Ameren Missouri** :: 3701 S Lindbergh Suite 204 :: St. Louis, MO 63127

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**Ameren Missouri** :: 3701 S Lindbergh Suite 204 :: St. Louis, MO 63127

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**From:** Mallory Huggins [mailto:Mallory.Huggins@nerc.net]  
**Sent:** Tuesday, December 13, 2011 2:38 PM  
**To:** grti\_sdt  
**Subject:** FAC-003 Exception Language

Hi everyone,

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I've attached what we have now. Any ideas? Ideally, we'd make this change this afternoon so we can post for ballot tomorrow, but we also have the option of holding off until the first week of January...

Thanks,  
Mallory

---

**Mallory Huggins**  
**Standards Specialist**  
**North American Electric Reliability Corporation**  
**1120 G Street NW, Suite 990, Washington, DC 20005**  
**(p): 202-383-2639 | (c): 609-619-1629 | (f): 202-393-3955**

---

Y

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**From:** [Dwyer IV, Samuel J](#)  
**To:** [Louis Slade](#); [Mallory Huggins](#)  
**Cc:** ["SHelyer@tnsk.com"](mailto:SHelyer@tnsk.com)  
**Subject:** RE: FAC-003 Exception Language  
**Date:** Tuesday, December 13, 2011 5:59:52 PM

---

Louis –

I think this will work. We could incorporate your wording, but I still end up with more words than Mallory's last suggestion. This is why I hate stringing phrases together with "and" or "or", but we don't have a choice if we want the recirc ballot.

Sam

**Sam Dwyer** :: Consulting Engineer, POS QMS :: T 314.957.3463  
**Ameren Missouri** :: 3701 S Lindbergh Suite 204 :: St. Louis, MO 63127

---

**From:** Louis Slade [mailto:louis.slade@dom.com]  
**Sent:** Tuesday, December 13, 2011 4:53 PM  
**To:** 'Mallory.Huggins@nerc.net'; Dwyer IV, Samuel J  
**Cc:** 'SHelyer@tnsk.com'  
**Subject:** Re: FAC-003 Exception Language

Ok by me

---

**From:** Mallory Huggins [mailto:Mallory.Huggins@nerc.net]  
**Sent:** Tuesday, December 13, 2011 05:49 PM  
**To:** Louis Slade (Services - 6); 'SDwyerIV@ameren.com' <SDwyerIV@ameren.com>  
**Cc:** 'SHelyer@tnsk.com' <SHelyer@tnsk.com>  
**Subject:** RE: FAC-003 Exception Language

I think the "or" can work – it's the same as the (a)/(b) structure we originally had, but without the (a) and (b). We could go the route you propose below, but I think the cleaner way (as in, we have to add the least amount of text) to do it is how we have it now.

---

**From:** Louis Slade [mailto:louis.slade@dom.com]  
**Sent:** Tuesday, December 13, 2011 5:47 PM  
**To:** 'SDwyerIV@ameren.com'; Mallory Huggins  
**Cc:** 'SHelyer@tnsk.com'  
**Subject:** Re: FAC-003 Exception Language

I think it looks pretty good. But is of 'or' correct? Should it be "and shorter lines that do not have a clear line of sight....." ?

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**To:** ["Dwyer IV, Samuel J"](#)  
**Cc:** [scott Helyer \(shelyer@tnsk.com\)](#); [Louis Slade \(louis.slade@dom.com\)](#)  
**Subject:** RE: FAC-003 Exception Language  
**Date:** Tuesday, December 13, 2011 5:18:00 PM

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**Sent:** Tuesday, December 13, 2011 2:38 PM  
**To:** grti\_sdt  
**Subject:** FAC-003 Exception Language

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**From:** [Dwyer IV, Samuel J](#)  
**To:** [Mallory Huggins](#)  
**Cc:** [Louis Slade](#); "[SHelyer@tnsk.com](mailto:SHelyer@tnsk.com)"  
**Subject:** RE: FAC-003 Exception Language  
**Date:** Wednesday, December 14, 2011 9:33:18 AM

---

Mallory –

You did a good job with the ramblings from Louis and me. Thanks for the great last minute effort!  
Sam

**Sam Dwyer** :: Consulting Engineer, POS QMS :: T 314.957.3463  
**Ameren Missouri** :: 3701 S Lindbergh Suite 204 :: St. Louis, MO 63127

---

**From:** Mallory Huggins [mailto:[Mallory.Huggins@nerc.net](mailto:Mallory.Huggins@nerc.net)]  
**Sent:** Wednesday, December 14, 2011 8:20 AM  
**To:** Louis Slade; Dwyer IV, Samuel J  
**Cc:** '[SHelyer@tnsk.com](mailto:SHelyer@tnsk.com)'  
**Subject:** RE: FAC-003 Exception Language

Louis, you were right that there were some folks concerned because their Facilities didn't have switchyards (and I raised that same concern when chatting with Laura about it), but I made a game time decision and rationalized that (1) leaving the switchyard language in there ensures that we change as little as possible between the last posting and now, and (2) we did get 85% support for our changes, so I feel comfortable sticking with that language if we must. I wrapped up everything last night and sent it on for posting, which will hopefully happen before noon. Here's the rationalization language I added both in a text box within the two FAC-003s, and in some of the other docs:

With the line of sight reference in 4.3.1, the SDT simply seeks to clarify the exception language based on the intent that has been agreed upon by the stakeholder body. In its [Consideration of Comments report](#) from the last formal comment period, which ended on July 17, 2011, the SDT explained "We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor." With the addition of an explicit line of sight reference here, the SDT believes it has clarified its original intent.

Hopefully this will get us there. I'm sorry about the last-minute scramble, but I really appreciate all the input!

---

**From:** Louis Slade [mailto:[louis.slade@dom.com](mailto:louis.slade@dom.com)]  
**Sent:** Tuesday, December 13, 2011 6:43 PM  
**To:** 'SDwyerIV@ameren.com'; Mallory Huggins  
**Cc:** '[SHelyer@tnsk.com](mailto:SHelyer@tnsk.com)'  
**Subject:** Re: FAC-003 Exception Language

Agree that we want to go to recirc. So don't make changes that prohibit doing so

---

**From:** Dwyer IV, Samuel J [mailto:SDwyerIV@ameren.com]  
**Sent:** Tuesday, December 13, 2011 06:31 PM  
**To:** Louis Slade (Services - 6); 'Mallory.Huggins@nerc.net' <Mallory.Huggins@nerc.net>  
**Cc:** 'SHelyer@tnsk.com' <SHelyer@tnsk.com>  
**Subject:** RE: FAC-003 Exception Language

Louis –

We did, so either is fine with me.

Mallory – you might want to try Louis' simpler words below first. If that doesn't fly, try the switchyard wording if that's what we need to put this out for recirc.

Louis – Is that OK with you? I'd hate to see us lose our momentum at the last minute and I don't think this is a deal-breaker – at least in my opinion.

Sam

**Sam Dwyer** :: Consulting Engineer, POS QMS :: T 314.957.3463  
**Ameren Missouri** :: 3701 S Lindbergh Suite 204 :: St. Louis, MO 63127

---

**From:** Louis Slade [mailto:louis.slade@dom.com]  
**Sent:** Tuesday, December 13, 2011 5:01 PM  
**To:** Dwyer IV, Samuel J; 'Mallory.Huggins@nerc.net'  
**Cc:** 'SHelyer@tnsk.com'  
**Subject:** Re: FAC-003 Exception Language

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**Sent:** Tuesday, December 13, 2011 5:04 PM  
**To:** Mallory Huggins  
**Cc:** scott Helyer (shelyer@tnsk.com); Louis Slade (louis.slade@dom.com)  
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**From:** Mallory Huggins [mailto:Mallory.Huggins@nerc.net]  
**Sent:** Tuesday, December 13, 2011 2:38 PM  
**To:** grti\_sdt  
**Subject:** FAC-003 Exception Language

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**North American Electric Reliability Corporation**  
**1120 G Street NW, Suite 990, Washington, DC 20005**  
**(p): 202-383-2639 | (c): 609-619-1629 | (f): 202-393-3955**

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**To:** [Mallory Huggins](#)  
**Cc:** [scott Helyer \(shelyer@tnsk.com\)](#); [Louis Slade \(louis.slade@dom.com\)](#)  
**Subject:** RE: FAC-003 Exception Language  
**Date:** Tuesday, December 13, 2011 5:04:38 PM  
**Attachments:** [20111213 SJD comment FAC-003-3\\_redline\\_to\\_last\\_posted.doc](#)

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**Date:** Tuesday, December 13, 2011 6:01:28 PM

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**Subject:** RE: FAC-003 Exception Language  
**Date:** Tuesday, December 13, 2011 5:44:17 PM

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**Subject:** RE: FAC-003 Exception Language

Sam, thanks so much for that. I think you might be going too far with the omission of transmission. I agree that it's a bit problematic, but with the disclaimer ("Within the text of NERC Reliability Standard FAC-003-3, "transmission line(s) and "applicable line(s) can also refer to the generation facilities as referenced in 4.3 and its subsections."), I think we can make it work.

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Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard **or do not have a clear line of sight from the origin of the line to the point of interconnection** and are:

Any thoughts? I'm going to give Laura a call and see if this is looking any better to her. If not, we might need another plan...

---

**From:** Dwyer IV, Samuel J [mailto:SDwyerIV@ameren.com]  
**Sent:** Tuesday, December 13, 2011 5:04 PM  
**To:** Mallory Huggins  
**Cc:** scott Helyer (shelyer@tnsk.com); Louis Slade (louis.slade@dom.com)  
**Subject:** RE: FAC-003 Exception Language

Mallory –

I don't know for sure if this is what you want, but see red-lines in Section 4.3 to the attached file. I may have gone too far, but that word "transmission" has been bothering me so your request gave me the chance to remove it yet clearly identify the line with "generation". I'm sure someone else can do better, but this is what I came up with...

Thanks,

Sam

**Sam Dwyer** :: Consulting Engineer, POS QMS :: T 314.957.3463  
**Ameren Missouri** :: 3701 S Lindbergh Suite 204 :: St. Louis, MO 63127

---

**From:** Mallory Huggins [mailto:Mallory.Huggins@nerc.net]  
**Sent:** Tuesday, December 13, 2011 2:38 PM  
**To:** grti\_sdt  
**Subject:** FAC-003 Exception Language

Hi everyone,

There's some concern that the exception language in FAC-003 may be perceived as changing the scope of the previous changes, which would mean the standard couldn't go to recirculation ballot and would have to be posted for comment again. I think we have some solid background to justify that it is just a clarifying change, because in a previous comment report we talked about line of sight being the goal – and now we are simply clarifying that. I'm working on some language that makes this clear for the comment report/technical justification document, but alongside that, we need to see if we can format the language change we've proposed in the standard a way that's a little more concise.

I've attached what we have now. Any ideas? Ideally, we'd make this change this afternoon so we can post for ballot tomorrow, but we also have the option of holding off until the first week of January...

Thanks,  
Mallory

---

**Mallory Huggins**  
**Standards Specialist**  
**North American Electric Reliability Corporation**  
**1120 G Street NW, Suite 990, Washington, DC 20005**  
**(p): 202-383-2639 | (c): 609-619-1629 | (f): 202-393-3955**

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**From:** Mallory Huggins  
**To:** ["Louis Slade"; "SDwyerIV@ameren.com"](#)  
**Cc:** ["SHelyer@tnsk.com"](#)  
**Subject:** RE: FAC-003 Exception Language  
**Date:** Wednesday, December 14, 2011 9:21:00 AM

---

Louis, you were right that there were some folks concerned because their Facilities didn't have switchyards (and I raised that same concern when chatting with Laura about it), but I made a game time decision and rationalized that (1) leaving the switchyard language in there ensures that we change as little as possible between the last posting and now, and (2) we did get 85% support for our changes, so I feel comfortable sticking with that language if we must. I wrapped up everything last night and sent it on for posting, which will hopefully happen before noon. Here's the rationalization language I added both in a text box within the two FAC-003s, and in some of the other docs:

With the line of sight reference in 4.3.1, the SDT simply seeks to clarify the exception language based on the intent that has been agreed upon by the stakeholder body. In its [Consideration of Comments report](#) from the last formal comment period, which ended on July 17, 2011, the SDT explained "We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor." With the addition of an explicit line of sight reference here, the SDT believes it has clarified its original intent.

Hopefully this will get us there. I'm sorry about the last-minute scramble, but I really appreciate all the input!

---

**From:** Louis Slade [mailto:louis.slade@dom.com]  
**Sent:** Tuesday, December 13, 2011 6:43 PM  
**To:** 'SDwyerIV@ameren.com'; Mallory Huggins  
**Cc:** 'SHelyer@tnsk.com'  
**Subject:** Re: FAC-003 Exception Language

Agree that we want to go to recirc. So don't make changes that prohibit doing so

---

**From:** Dwyer IV, Samuel J [mailto:SDwyerIV@ameren.com]  
**Sent:** Tuesday, December 13, 2011 06:31 PM  
**To:** Louis Slade (Services - 6); 'Mallory.Huggins@nerc.net' <Mallory.Huggins@nerc.net>  
**Cc:** 'SHelyer@tnsk.com' <SHelyer@tnsk.com>  
**Subject:** RE: FAC-003 Exception Language

Louis –

We did, so either is fine with me.

Mallory – you might want to try Louis' simpler words below first. If that doesn't fly, try the switchyard wording if that's what we need to put this out for recirc.

Louis – Is that OK with you? I'd hate to see us lose our momentum at the last minute and I don't think this is a deal-breaker – at least in my opinion.

Sam

**Sam Dwyer** :: Consulting Engineer, POS QMS :: T 314.957.3463  
**Ameren Missouri** :: 3701 S Lindbergh Suite 204 :: St. Louis, MO 63127

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**From:** Louis Slade [mailto:louis.slade@dom.com]  
**Sent:** Tuesday, December 13, 2011 5:01 PM  
**To:** Dwyer IV, Samuel J; 'Mallory.Huggins@nerc.net'  
**Cc:** 'SHelyer@tnsk.com'  
**Subject:** Re: FAC-003 Exception Language

One thing troubles me. Didn't we have comments in this or past that stated some generating facilities don't have switch yards? If so, maybe just say clear line of sight between GSU and point of interconnection

---

**From:** Louis Slade (Services - 6)  
**Sent:** Tuesday, December 13, 2011 05:47 PM  
**To:** 'SDwyerIV@ameren.com' <SDwyerIV@ameren.com>; 'Mallory.Huggins@nerc.net' <Mallory.Huggins@nerc.net>  
**Cc:** 'SHelyer@tnsk.com' <SHelyer@tnsk.com>  
**Subject:** Re: FAC-003 Exception Language

I think it looks pretty good. But is of 'or' correct? Should it be "and shorter lines that do not have a clear line of sight....." ?

---

**From:** Dwyer IV, Samuel J [mailto:SDwyerIV@ameren.com]  
**Sent:** Tuesday, December 13, 2011 05:41 PM  
**To:** Mallory Huggins <Mallory.Huggins@nerc.net>  
**Cc:** scott Helyer (shelyer@tnsk.com) <shelyer@tnsk.com>; Louis Slade (Services - 6)  
**Subject:** RE: FAC-003 Exception Language

Mallory –

The whole premise from day one was use of the concept of "clear line of sight", so I don't see a problem or any reason to think we've made any fundamental changes. If you look at the wording changes on face value alone, you may conclude that, but we have not veered from our initial concept. Hang tough because there's no reason to think we've made any change that should prevent a recirc ballot. I know Louis is on vacation, but maybe Scott can confirm this.

Thanks,

Sam

**Sam Dwyer** :: Consulting Engineer, POS QMS :: T 314.957.3463  
**Ameren Missouri** :: 3701 S Lindbergh Suite 204 :: St. Louis, MO 63127

---

**From:** Mallory Huggins [mailto:Mallory.Huggins@nerc.net]  
**Sent:** Tuesday, December 13, 2011 4:33 PM  
**To:** Dwyer IV, Samuel J  
**Cc:** scott Helyer (shelyer@tnsk.com); Louis Slade (louis.slade@dom.com)  
**Subject:** RE: FAC-003 Exception Language

I like that proposal...I was feeling similarly weird about the "origin of the line" thing. With your change, it would look like this:

Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard **or do not have a clear line of sight from the switchyard fence to the point of interconnection** and are:

All this discussion is making me a little bit nervous that stakeholders will see this is a bigger change than we think it is, but I'll do my best to write a really clear explanation. After our discussions in DC, I couldn't in good faith remove the line of sight reference altogether – I think it gets us a lot closer to demonstrating the reliability-based need for the exception.

---

**From:** Dwyer IV, Samuel J [mailto:SDwyerIV@ameren.com]  
**Sent:** Tuesday, December 13, 2011 5:27 PM  
**To:** Mallory Huggins  
**Cc:** scott Helyer (shelyer@tnsk.com); Louis Slade (louis.slade@dom.com)  
**Subject:** RE: FAC-003 Exception Language

Mallory –

I think you've got it. I have a thing for always trying to state the positive, rather than the negative, but I agree the negative is what you want in this case. I would suggest one more change, instead of "from the origin of the line" use "from the switchyard fence". It sounds a little repetitive, but I'm concerned the phrase "origin of the line" is too vague. Is the "origin of the line" the generator terminals inside the plant? The low-side of the GSU? The high-side of the GSU? The first tower outside of the switchyard?

Sam

**Sam Dwyer** :: Consulting Engineer, POS QMS :: T 314.957.3463  
**Ameren Missouri** :: 3701 S Lindbergh Suite 204 :: St. Louis, MO 63127

---

**From:** Mallory Huggins [mailto:Mallory.Huggins@nerc.net]  
**Sent:** Tuesday, December 13, 2011 4:19 PM  
**To:** Dwyer IV, Samuel J  
**Cc:** scott Helyer (shelyer@tnsk.com); Louis Slade (louis.slade@dom.com)  
**Subject:** RE: FAC-003 Exception Language

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Any thoughts? I'm going to give Laura a call and see if this is looking any better to her. If not, we might need another plan...

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**Sent:** Tuesday, December 13, 2011 5:04 PM  
**To:** Mallory Huggins  
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**Subject:** RE: FAC-003 Exception Language

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Thanks,  
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**From:** Mallory Huggins [mailto:Mallory.Huggins@nerc.net]  
**Sent:** Tuesday, December 13, 2011 2:38 PM  
**To:** grti\_sdt  
**Subject:** FAC-003 Exception Language

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Thanks,  
Mallory

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**Standards Specialist**



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Ameren Corporation

February 14, 2012

Via E-Mail

Mr. Steven T. Naumann  
Vice President, Wholesale Market Development  
Federal Regulatory Affairs & Public Policy  
Exelon Corporation  
Chase Tower-50th Floor  
10 S. Dearborn Street  
Chicago, Il 60603

Re: Exelon Level 1 Appeal of FAC-003x in Project 2010-07

Dear Steve,

In my role as Director of Standards you informed me, on January 13, 2012, of the possibility of filing an appeal. On January 20, 2012 you filed, on the behalf of Exelon Corporation, a Level 1 Appeal of the processing of FAC-003 in Project 2010-07 under the NERC standards development process and the Rules of Procedure Section 300. In its appeal Exelon is contending that there was an improperly implemented, substantive change to the standard (R4.3.1) regarding "line of site" between the last successive and recirculation ballot.

Level 1 Appeals are managed within the current NERC Standard Processes Manual (SPM) dated September 3, 2010 as follows:

- Any entity that has directly and materially affected interests and that has been or will be adversely affected by any procedural action or inaction related to the development, approval, revision, reaffirmation, or withdrawal of a reliability standard, definition, variance, associated implementation plan, or interpretation shall have the right to appeal. This appeals process applies only to the NERC reliability standards processes as defined in this manual, not to the technical content of the standards action.

The burden of proof to show adverse effect shall be on the appellant. Appeals shall be made within 30 days of the date of the action purported to cause the adverse effect, except appeals for inaction, which may be made at any time.

3353 Peachtree Road NE  
Suite 600, North Tower  
Atlanta, GA 30326  
404-446-2560 | [www.nerc.com](http://www.nerc.com)

The final decisions of any appeal shall be documented in writing and made public.

The appeals process provides two levels, with the goal of expeditiously resolving the issue to the satisfaction of the participants.

- **Level 1 Appeal**  
Level 1 is the required first step in the appeals process. The appellant shall submit (to the Director of Standards) a complaint in writing that describes the procedural action or inaction associated with the standards process. The appellant shall describe in the complaint the actual or potential adverse impact to the appellant. Assisted by staff and industry resources as needed, the Director of Standards shall prepare a written response addressed to the appellant as soon as practical but not more than 45 days after receipt of the complaint. If the appellant accepts the response as a satisfactory resolution of the issue, both the complaint and response shall be made a part of the public record associated with the standard.

The FAC-003-x standard had been scheduled for Board of Trustees approval at its February 9, 2012 meeting, however, in order to permit the Level 1 Appeal process to properly run, it has been withdrawn.

### **Information Requests**

In response to the Level 1 Appeal, three information requests, each containing two questions, were issued on January 25, 2012. One was issued to Exelon, one to NERC Standards Process Staff and one to the Project 2010-07 Standards Drafting Team (SDT) Chair. The information requests and the responses are appended to this letter which will be posted on the NERC website.

### **Findings**

#### ***Timeliness of the Appeal:***

The Standard Processes Manual calls for the filing of the appeal within 30 days of the date of the action purported to cause the direct material adverse impact. The standard with the “line of site change” was posted on December 14, 2011 and the ballot was finalized on December 23, 2011.

Within the project notice posted on December 14, 2011 it was clearly stated:

“In FAC-003-X and FAC-003-3, the SDT added a clarifying reference to line of sight in the GO exemption in section 4.3.1. of both versions; corrected a typo in 4.3.1.2 of FAC-003-3; and changed “RE” to “Regional Entity” in 4.3.1 of FAC-003-X.”

In its response to the first information request Exelon notes its position that the adverse impact did not occur until the ballot was concluded (unfavorably in Exelon's view). On this basis Exelon believes its January 13, 2012 preliminary notice of intent to file an appeal and the January 20, 2012 filing of the appeal was timely under the SPM. I will consider the filing of this Level 1 Appeal as having been made timely.

***Adverse Impact:***

Exelon notes in its response to Information Request 1 that it considers the direct material adverse impact to be that it would be now subject as a Generator Owner/Generator Operator (GO/GOP) to the proposed FAC-003-x standard given the line of sight clarification. It is a fair question as to whether having a standard become applicable to a given entity is truly an adverse impact? If that were the case, then every registered function would contend the same. I find that it is not an adverse impact for a subset of Exelon's nuclear facilities to become subject to the standard. Applicability by itself is not an adverse impact. The interests of reliability must be served and if the SDT determines that a given set of circumstances should result in a standard becoming applicable, then that is the technical design. On the basis of applicability the appeal fails. The SDT in this project was charged specifically with the task of determining which standards and requirements should be adjusted (and how they should be adjusted) for applicability to GOs/GOPs.

***Procedural Action:***

Exelon believes that it did not have ample time to respond to the proposed change. Exelon contends it was denied the ability to inform the industry. Exelon did provide some information of its efforts to inform the industry of its beliefs, although apparently it was unpersuasive, given the outcome of the ballot.

***Material Change:***

Based on the information request response from the SDT Chair, the SDT believes that the "line of sight" change it made was clarifying and not material. I agree with Exelon, however that the line of sight change also had the effect of changing the applicability of the standard based on its construct as Exelon contends. This is within the technical scope for the SDT under the process. On this basis, I find that Exelon has made its case that the SPM was not adhered to and that a change impacting applicability was made between the last successive and recirculation ballot.

**Recommended Actions and Options**

I refer the issue to the Standards Committee for handling. There are several options to consider:

1. Re-post the standard for a successive ballot and recirculation ballot. Essentially set the clock back and correctly replay the last steps of the process.
2. Ask the SDT to remove the clarification language from the final standard and go directly to recirculation ballot.
3. Ask the SDT to redesign the challenged portion of the proposed standard.

I recommend the Standards Committee pursue option 2.

Sincerely,



Herb Schrayshuen  
Vice President, Standards and Training

cc: Mr. Gerry. Cauley, President and CEO, NERC  
Mr. Ken Peterson, Chair, Board of Trustees Standards Oversight and Technology Committee  
Mr. David Cook, General Counsel, NERC  
Ms. Holly Hawkins, Associate General Counsel, NERC  
Mr. Michael Moon, Director Compliance Operations, NERC  
Ms. Laura Hussey, Manager Standards Process, NERC  
Ms. Mallory Huggins, GO/TO Standards Drafting Team Advisor, NERC  
Mr. Allen Mosher, Chair, Standards Committee  
Mr. Louis Slade, Chair, GO/TO Standards Drafting Team

**Attachments:**

- 1) Appeal Letter dated January 20, 2012 from Exelon
- 2) Exelon Response to Data/Information Request
- 3) Information Request 1 to NERC Standards Process Staff (plus response)
- 4) Information Request 1 to GO/TO Drafting Team Chair (plus response)

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary. When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.*

### **Right-of-Way (ROW)**

A corridor of land on which electric lines may be located. The applicable Transmission Owner or applicable Generator Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

The current glossary definition of this NERC term was modified to include applicable Generator Owners.

FAC-003-2 was developed under Project 2007-07. The standard was balloted and adopted by the NERC Board of Trustees, but the Project 2010-07 drafting team does not want to assume that FAC-003-2 will be approved by FERC and other governmental authorities. Thus, the Project 2010-07 drafting team has developed two sets of proposed changes: one to this version, FAC-003-1, the current FERC-approved version of the standard, and one to FAC-003-2, the version developed by the Project 2007-07 team and adopted by NERC’s Board of Trustees.

**A. Introduction**

**1. Title:** Transmission Vegetation Management Program

**2. Number:** FAC-003-X

**3. Purpose:** To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission Rights-of-Way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation-related outages of the transmission systems to the respective Regional Entity and the North American Electric Reliability Corporation (NERC).

Within the text of NERC Reliability Standard FAC-003-X, “transmission line(s)” and “applicable line(s)” can also refer to the generation Facilities as referenced in 4.4 and its subsections.

**4. Applicability:**

**4.1.** Regional Entity

**4.2.** Applicable Transmission Owner

**4.2.1.** Transmission Owner that owns overhead transmission lines operated at 200 kV and above and to any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.

**4.3.** Applicable Generator Owner

**4.3.1.** Generator Owner that owns an applicable qualified Facility, where a qualified Facility is an overhead transmission line(s) that (1) extends greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner’s Facility or (2) does not have a clear line of sight<sup>1</sup> from the generating station switchyard fence to the point of interconnection with a Transmission Owner’s Facility and is operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.

**4.4.** Applicable Facilities

**4.4.1.** Transmission lines owned by a Transmission Owner that are operated at 200kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.

**4.4.2.** Qualified Facilities owned by applicable Generator Owners.

---

<sup>1</sup> “Clear line of sight” means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.



**5. Effective Dates:**

There are three effective dates associated with this implementation plan:

The first effective date applies to Transmission Owners.

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner become effective upon Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

The second effective date allows Generator Owners time to prepare a formal transmission vegetation management program as outlined in Requirement R1.

In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees' adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

The third effective date allows entities time to comply with Requirements R2, R3, and R4.

In those jurisdictions where regulatory approval is required, Requirements R2, R3, and R4 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R2, R3, and R4 become effective on the first day of the first calendar quarter two years following Board of Trustees' adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

**B. Requirements**

**R1.** Each applicable Transmission Owner or applicable Generator Owner shall prepare and keep current a formal transmission vegetation management program (TVMP). The TVMP shall include the applicable Transmission Owner's or applicable Generator Owner's objectives, practices, approved procedures, and work specifications<sup>2</sup>.

**R1.1.** The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the applicable Transmission Owner's or applicable Generator Owner's transmission lines.

**R1.2.** Each applicable Transmission Owner or applicable Generator Owner in the TVMP shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the applicable

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<sup>2</sup> ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.

Transmission Owner or applicable Generator Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.

**R1.2.1.** Clearance 1 — The applicable Transmission Owner or applicable Generator Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the applicable Transmission Owner or applicable Generator Owner plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.

**R1.2.2.** Clearance 2 — The applicable Transmission Owner or applicable Generator Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These applicable Transmission Owner-specific or applicable Generator Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.

**R1.2.2.1** Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.

**R1.2.2.2** Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.

**R1.3.** All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner or Generator Owner, to perform their duties.

**R1.4.** Each applicable Transmission Owner or applicable Generator Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner or applicable Generator Owner is restricted from attaining the clearances specified in Requirement 1.2.1.

**R1.5.** Each Transmission Owner or applicable Generator Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.

*[VRF – High]*

- R2.** Each applicable Transmission Owner or applicable Generator Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each applicable Transmission Owner or applicable Generator Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.

*[VRF – High]*

- R3.** Each applicable Transmission Owner or applicable Generator Owner shall report quarterly to its Regional Entity, or the Regional Entity’s designee, sustained transmission line outages determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation.

**R3.1.** Multiple sustained 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.

**R3.2.** The applicable Transmission Owner or applicable Generator Owner is not required to report to the Regional Entity, or the Regional Entity’s designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).

**R3.3.** The outage information provided by the applicable Transmission Owner or applicable Generator Owner to the Regional Entity, or the Regional Entity’s designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

**R3.4.** An outage shall be categorized as one of the following:

**R3.4.1.** Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;

**R3.4.2.** Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;

**R3.4.3.** Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.

*[VRF – Lower]*

- R4.** The Regional Entity shall report the outage information provided to it by applicable Transmission Owners or applicable Generator Owners, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported outages.

*[VRF – Lower]*

**C. Measures**

- M1.** Each applicable Transmission Owner or applicable Generator Owner has a documented TVMP, as identified in Requirement 1.
- M1.1.** Each applicable Transmission Owner or applicable Generator Owner has documentation that the applicable Transmission Owner or applicable Generator Owner performed the vegetation inspections as identified in Requirement 1.1.
- M1.2.** Each applicable Transmission Owner or applicable Generator Owner has documentation that describes the clearances identified in Requirement 1.2.
- M1.3.** Each applicable Transmission Owner or applicable Generator Owner has documentation that the personnel directly involved in the design and implementation of the applicable Transmission Owner’s or applicable Generator Owner TVMP hold the qualifications identified by the Transmission Owner or applicable Generator Owner as required in Requirement 1.3.
- M1.4.** Each applicable Transmission Owner or applicable Generator Owner has documentation that it has identified any areas not meeting the applicable Transmission Owner’s or applicable Generator Owner’s standard for vegetation management and any mitigating measures the Transmission Owner or applicable Generator Owner has taken to address these deficiencies as identified in Requirement 1.4.
- M1.5.** Each applicable Transmission Owner or applicable Generator Owner has a documented process for the immediate communication of imminent threats by vegetation as identified in Requirement 1.5.
- M2.** Each applicable Transmission Owner or applicable Generator Owner has documentation that the Transmission Owner implemented the work plan identified in Requirement 2.
- M3.** Each applicable Transmission Owner or applicable Generator Owner has documentation that it has supplied quarterly outage reports to the Regional Entity, or the Regional Entity’s designee, as identified in Requirement 3.
- M4.** The Regional Entity has documentation that it provided quarterly outage reports to NERC as identified in Requirement 4.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the Compliance Enforcement Authority.

**1.2. Compliance Monitoring and Enforcement Processes:**

Compliance Audit

Self-Certification  
 Spot Checking  
 Compliance Investigation  
 Self-Reporting  
 Complaint

**1.3. Data Retention**

The applicable Transmission Owner and applicable Generator Owner shall keep data or evidence to show compliance as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The applicable Transmission Owner and applicable Generator Owner shall retain evidence of Requirement 1, Measure 1, Requirement 2, Measure 2, and Requirement 3, Measure 3 from its last audit.

**1.4. Additional Compliance Information**

None.

**2. Violation Severity Levels**

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity did not include and keep current one of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current two of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current three of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current all required elements of the TVMP, as directed by the requirement.
R1.1	N/A	N/A	The applicable entity TVMP did not define a schedule, as directed by the requirement, or the type of ROW vegetation inspections, as directed by the requirement.	The applicable entity TVMP did not define a schedule, as directed by the requirement, nor the type of ROW vegetation inspections, as directed by the requirement.
R1.2	N/A	N/A	N/A	The responsible entity, in its TVMP, failed to identify and document clearances between vegetation and any

				<p>overhead, ungrounded supply conductors.</p> <p>OR</p> <p>The responsible entity, in its TVMP, failed to take into consideration transmission line voltage, or the effects of ambient temperature on conductor sag under maximum design loading, or the effects of wind velocities on conductor sway.</p> <p>OR</p> <p>The responsible entity, in its TVMP, failed to establish Clearance 1 or Clearance 2 values.</p>
R1.2.1	N/A	N/A	N/A	<p>The responsible entity failed to determine and document an appropriate clearance distance to be achieved at the time of transmission vegetation management work taking into account local conditions and the expected time frame in which the responsible entity expects to return for future vegetation management work.</p>

				OR The responsible entity documented a Clearance 1 value that was smaller than its Clearance 2 value.
R1.2.2	N/A	N/A	N/A	The responsible entity failed to determine and document Clearance 2 values taking into account local conditions and the expected time frame in which the responsible entity expects to return for future vegetation management work.
R1.2.2.1	N/A	N/A	N/A	Where transmission system transient overvoltage factors were known, clearances were not derived from Table 5, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.
R1.2.2.2	N/A	N/A	N/A	Where transmission system transient overvoltage factors are known, clearances were not derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.
R1.3	For responsible entities directly	For responsible entities directly	For responsible entities directly	For responsible entities directly

	involving fewer than 20 persons in the design and implementation of the TVMP, one of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, 5% or less of those persons did not hold appropriate qualifications and training to perform their duties.	involving fewer than 20 persons in the design and implementation of the TVMP, two of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 5% up to (and including) 10% of those persons did not hold appropriate qualifications and training to perform their duties.	involving fewer than 20 persons in the design and implementation of the TVMP, three of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 10% up to (and including) 15% of those persons did not hold appropriate qualifications and training to perform their duties.	involving fewer than 20 persons in the design and implementation of the TVMP, more than three of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 15% of those persons did not hold appropriate qualifications and training to perform their duties.
R1.4	N/A	N/A	N/A	The responsible entity's TVMP does not include mitigation measures to achieve sufficient clearances where restrictions to the ROW are in effect.
R1.5	N/A	N/A	N/A	The responsible entity did not establish or did not document a process for the immediate communication of vegetation conditions that present an imminent threat of line outage, as directed by the requirement.
R2	The responsible entity did not meet one of the three required elements	The responsible entity did not meet two of the three required elements	The responsible entity did not meet the three required elements	The responsible entity does not have an annual plan for vegetation



	(including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	(including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	(including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	management.  OR  The responsible entity has not implemented the annual plan for vegetation management.
R3	The responsible entity failed to provide a quarterly outage report, but did not experience any reportable outages.  OR  The responsible entity provided a quarterly report, but failed to report in the manner specified by one or more of the following subcomponents of Requirement R3: R3.1 or R3.2.	The responsible entity provided a quarterly report, but failed to include information required by R3.3.	The responsible entity provided a quarterly outage report, but failed to include a reportable Category 3 outage as described in R3.4.3.	The responsible entity experienced reportable outages but failed to provide a quarterly report.  OR  The responsible entity provided a quarterly outage report, but failed to include a reportable Category 1 (as described in R3.4.1) or Category 2 outage (as described in R3.4.2).
R4	N/A	N/A	N/A	N/A

**E. Regional Differences**

None Identified.

**Version History**

Version	Date	Action	Change Tracking
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**Standard FAC-003-X — Transmission Vegetation Management Program**

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1	TBA	<ol style="list-style-type: none"> <li>1. Added “Standard Development Roadmap.”</li> <li>2. Changed “60” to “Sixty” in section A, 5.2.</li> <li>3. Added “Proposed Effective Date: April 7, 2006” to footer.</li> <li>4. Added “Draft 3: November 17, 2005” to footer.</li> </ol>	01/20/06
X	April 23, 2012	Made standard applicable to certain qualifying Generator Owners and brought overall standard format up to date; added VSLs approved by FERC	Revision under Project 2010-07

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary. When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.*

### **Right-of-Way (ROW)**

A corridor of land on which electric lines may be located. The applicable Transmission Owner or applicable Generator Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

The current glossary definition of this NERC term was modified to include applicable Generator Owners.

FAC-003-2 was developed under Project 2007-07. The standard was balloted and adopted by the NERC Board of Trustees, but the Project 2010-07 drafting team does not want to assume that FAC-003-2 will be approved by FERC and other governmental authorities. Thus, the Project 2010-07 drafting team has developed two sets of proposed changes: one to this version, FAC-003-1, the current FERC-approved version of the standard, and one to FAC-003-2, the version developed by the Project 2007-07 team and adopted by NERC's Board of Trustees.

## A. Introduction

1. **Title:** Transmission Vegetation Management Program

2. **Number:** FAC-003-X

3. **Purpose:** To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission ~~rights~~Rights-of-way Way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation-related outages of the transmission systems to the respective Regional Entity (~~RE~~) and the North American Electric Reliability ~~Council~~ Corporation (NERC).

Within the text of NERC Reliability Standard FAC-003-X, “transmission line(s)” and “applicable line(s)” can also refer to the generation Facilities as referenced in 4.4 and its subsections.

### 4. Applicability:

#### 4.1. Regional Entity

##### 4.1.4.2. Applicable Transmission Owner

4.1.1.4.2.1. Transmission Owner that owns overhead transmission lines operated at 200 kV and above and to any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.

##### 4.2.4.3. Applicable Generator Owner

4.3.1. Generator Owner that owns an applicable qualified Facility, where a qualified Facility is an overhead transmission line(s) that (1) extends greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) does not have a clear line of sight<sup>1</sup> from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and is operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.

#### 4.4. Applicable Facilities

4.4.1. Transmission lines owned by a Transmission Owner that are operated at 200kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.

4.2.1.4.4.2. Qualified Facilities owned by applicable Generator Owners.

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<sup>1</sup> “Clear line of sight” means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.

## 5. Effective Dates:

There are three effective dates associated with this implementation plan:

The first effective date applies to Transmission Owners.

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner become effective upon Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

The second effective date allows Generator Owners time to prepare a formal transmission vegetation management program as outlined in Requirement R1.

In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

The third effective date allows entities time to comply with Requirements R2, R3, and R4.

In those jurisdictions where regulatory approval is required, Requirements R2, R3, and R4 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R2, R3, and R4 become effective on the first day of the first calendar quarter two years following Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

## B. Requirements

**R1.** Each applicable Transmission Owner or applicable Generator Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the applicable Transmission Owner's or applicable Generator Owner's objectives, practices, approved procedures, and work specifications<sup>2</sup>.

**R1.1.** The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the applicable Transmission Owner's or applicable Generator Owner's transmission lines.

**R1.2.** Each applicable Transmission Owner or applicable Generator Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the applicable Transmission Owner or applicable Generator Owner shall establish clearances to be

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<sup>2</sup> ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.

achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.

**R1.2.1.** Clearance 1 — The applicable Transmission Owner or applicable Generator Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the applicable Transmission Owner or applicable Generator Owner plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.

**R1.2.2.** Clearance 2 — The applicable Transmission Owner or applicable Generator Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These applicable Transmission Owner-specific or applicable Generator Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.

**R1.2.2.1** Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.

**R1.2.2.2** Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.

**R1.3.** All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner or Generator Owner, to perform their duties.

**R1.4.** Each applicable Transmission Owner or applicable Generator Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner or applicable Generator Owner is restricted from attaining the clearances specified in Requirement 1.2.1.

**R1.5.** Each Transmission Owner or applicable Generator Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.

[VRF – High]

**R2.** Each applicable Transmission Owner or applicable Generator Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each applicable Transmission Owner or applicable Generator Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.

*[VRF – High]*

**R3.** Each applicable Transmission Owner or applicable Generator Owner shall report quarterly to its Regional Entity, or the Regional Entity’s designee, sustained transmission line outages determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation.

**R3.1.** Multiple sustained 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.

**R3.2.** The applicable Transmission Owner or applicable Generator Owner is not required to report to the Regional Entity, or the Regional Entity’s designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).

**R3.3.** The outage information provided by the applicable Transmission Owner or applicable Generator Owner to the Regional Entity, or the Regional Entity’s designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

**R3.4.** An outage shall be categorized as one of the following:

**R3.4.1.** Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;

**R3.4.2.** Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;

**R3.4.3.** Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.

*[VRF – Lower]*

- R4.** The Regional Entity shall report the outage information provided to it by applicable Transmission Owners or applicable Generator Owners, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported outages.

*[VRF – Lower]*

**C. Measures**

- M1.** Each applicable Transmission Owner or applicable Generator Owner has a documented TVMP, as identified in Requirement 1.
- M1.1.** Each applicable Transmission Owner or applicable Generator Owner has documentation that the applicable Transmission Owner or applicable Generator Owner performed the vegetation inspections as identified in Requirement 1.1.
- M1.2.** Each applicable Transmission Owner or applicable Generator Owner has documentation that describes the clearances identified in Requirement 1.2.
- M1.3.** Each applicable Transmission Owner or applicable Generator Owner has documentation that the personnel directly involved in the design and implementation of the applicable Transmission Owner’s or applicable Generator Owner TVMP hold the qualifications identified by the Transmission Owner or applicable Generator Owner as required in Requirement 1.3.
- M1.4.** Each applicable Transmission Owner or applicable Generator Owner has documentation that it has identified any areas not meeting the applicable Transmission Owner’s or applicable Generator Owner’s standard for vegetation management and any mitigating measures the Transmission Owner or applicable Generator Owner has taken to address these deficiencies as identified in Requirement 1.4.
- M1.5.** Each applicable Transmission Owner or applicable Generator Owner has a documented process for the immediate communication of imminent threats by vegetation as identified in Requirement 1.5.
- M2.** Each applicable Transmission Owner or applicable Generator Owner has documentation that the Transmission Owner implemented the work plan identified in Requirement 2.
- M3.** Each applicable Transmission Owner or applicable Generator Owner has documentation that it has supplied quarterly outage reports to the Regional Entity, or the Regional Entity’s designee, as identified in Requirement 3.
- M4.** The Regional Entity has documentation that it provided quarterly outage reports to NERC as identified in Requirement 4.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the Compliance Enforcement Authority.

~~Compliance Monitor:~~

- ~~• Regional Entity for the Transmission Owner and Generator Owner~~



- ~~Electric Reliability Organization or another Regional Entity approved by the ERO and FERC or other applicable government authorities~~

**1.2. Compliance Monitoring and Enforcement Processes:**

- Compliance Audits~~s~~
- Self-Certification~~s~~
- Spot Checking
- Compliance ~~Violation~~ Investigations
- Self-Reporting
- Complaint~~s~~

**1.3. Data Retention**

The applicable Transmission Owner and applicable Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The applicable Transmission Owner and applicable Generator Owner shall retain evidence of Requirement 1, Measure 1, Requirement 2, Measure 2, and Requirement 3, Measure 3 from its last audit.

**1.4. Additional Compliance Information**

None.

**2. Violation Severity Levels**

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity did not include and keep current one of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current two of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current three of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current all required elements of the TVMP, as directed by the requirement.
R1.1	N/A	N/A	The applicable entity TVMP did not define a schedule, as directed by the requirement, or the type of ROW vegetation inspections, as directed by the requirement.	The applicable entity TVMP did not define a schedule, as directed by the requirement, nor the type of ROW vegetation inspections, as directed by the requirement.
R1.2	N/A	N/A	N/A	The responsible entity, in its

				<p>TVMP, failed to identify and document clearances between vegetation and any overhead, ungrounded supply conductors.</p> <p>OR</p> <p>The responsible entity, in its TVMP, failed to take into consideration transmission line voltage, or the effects of ambient temperature on conductor sag under maximum design loading, or the effects of wind velocities on conductor sway.</p> <p>OR</p> <p>The responsible entity, in its TVMP, failed to establish Clearance 1 or Clearance 2 values.</p>
R1.2.1	N/A	N/A	N/A	<p>The responsible entity failed to determine and document an appropriate clearance distance to be achieved at the time of transmission vegetation management work taking into account local conditions and the expected time frame in</p>

				<p>which the responsible entity expects to return for future vegetation management work.</p> <p>OR</p> <p>The responsible entity documented a Clearance 1 value that was smaller than its Clearance 2 value.</p>
R1.2.2	N/A	N/A	N/A	<p>The responsible entity failed to determine and document Clearance 2 values taking into account local conditions and the expected time frame in which the responsible entity expects to return for future vegetation management work.</p>
R1.2.2.1	N/A	N/A	N/A	<p>Where transmission system transient overvoltage factors were known, clearances were not derived from Table 5, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.</p>
R1.2.2.2	N/A	N/A	N/A	<p>Where transmission system transient overvoltage factors are known, clearances were not derived from Table 7, IEEE 516-2003, phase-</p>

				to-phase voltages, with appropriate altitude correction factors applied.
R1.3	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, one of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, 5% or less of those persons did not hold appropriate qualifications and training to perform their duties.	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, two of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 5% up to (and including) 10% of those persons did not hold appropriate qualifications and training to perform their duties.	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, three of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 10% up to (and including) 15% of those persons did not hold appropriate qualifications and training to perform their duties.	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, more than three of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 15% of those persons did not hold appropriate qualifications and training to perform their duties.
R1.4	N/A	N/A	N/A	The responsible entity's TVMP does not include mitigation measures to achieve sufficient clearances where restrictions to the ROW are in effect.
R1.5	N/A	N/A	N/A	The responsible entity did not establish or did not document a process for the immediate communication of vegetation conditions that present an imminent threat of line outage, as

				directed by the requirement.
R2	The responsible entity did not meet one of the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	The responsible entity did not meet two of the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	The responsible entity did not meet the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	The responsible entity does not have an annual plan for vegetation management.  OR  The responsible entity has not implemented the annual plan for vegetation management.
R3	The responsible entity failed to provide a quarterly outage report, but did not experience any reportable outages.  OR  The responsible entity provided a quarterly report, but failed to report in the manner specified by one or more of the following subcomponents of Requirement R3: R3.1 or R3.2.	The responsible entity provided a quarterly report, but failed to include information required by R3.3.	The responsible entity provided a quarterly outage report, but failed to include a reportable Category 3 outage as described in R3.4.3.	The responsible entity experienced reportable outages but failed to provide a quarterly report.  OR  The responsible entity provided a quarterly outage report, but failed to include a reportable Category 1 (as described in R3.4.1) or Category 2 outage (as described in R3.4.2).
R4	N/A	N/A	N/A	N/A

E. Regional Differences

None Identified.

**Version History**

Version	Date	Action	Change Tracking
1	TBA	<ol style="list-style-type: none"> <li>1. Added “Standard Development Roadmap.”</li> <li>2. Changed “60” to “Sixty” in section A, 5.2.</li> <li>3. Added “Proposed Effective Date: April 7, 2006” to footer.</li> <li>4. Added “Draft 3: November 17, 2005” to footer.</li> </ol>	01/20/06
X	<del>May 16, 2011</del> <u>April 23, 2012</u>	Made standard applicable to certain qualifying Generator Owners and brought overall standard format up to date; <u>added VSLs approved by FERC</u>	Revision under Project 2010-07

### Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary. When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.*

#### **Right-of-Way (ROW)**

A corridor of land on which electric lines may be located. The applicable Transmission Owner or applicable Generator Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

The current glossary definition of this NERC term was modified to include applicable Generator Owners.

FAC-003-2 was developed under Project 2007-07. The standard was balloted and adopted by the NERC Board of Trustees, but the Project 2010-07 drafting team does not want to assume that FAC-003-2 will be approved by FERC and other governmental authorities. Thus, the Project 2010-07 drafting team has developed two sets of proposed changes: one to this version, FAC-003-1, the current FERC-approved version of the standard, and one to FAC-003-2, the version developed by the Project 2007-07 team and adopted by NERC's Board of Trustees.

A. Introduction

1. Title: Transmission Vegetation Management Program

2. Number: FAC-003-~~1X~~

3. Purpose: To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission ~~rights~~Rights-of-way~~Way~~ (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation-related outages of the transmission systems to the respective Regional ~~Reliability Organizations (RRO)~~Entity and the North American Electric Reliability ~~Council~~Corporation (NERC).

Within the text of NERC Reliability Standard FAC-003-X, “transmission line(s)” and “applicable line(s)” can also refer to the generation Facilities as referenced in 4.4 and its subsections.

4. Applicability:

4.1. Regional Entity

4.1.4.2. Applicable Transmission Owner:

4.2. Regional Reliability Organization:

4.2.1. This standard shall apply to all Transmission Owner that owns overhead transmission lines operated at 200 kV and above and to any lower voltage lines designated by the ~~RRO~~Regional Entity as critical to the reliability of the electric system in the region.

4.3. Applicable Generator Owner

4.3.1. Generator Owner that owns an applicable qualified Facility, where a qualified Facility is an overhead transmission line(s) that (1) extends greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) does not have a clear line of sight<sup>1</sup> from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and is operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.

4.4. Applicable Facilities

4.4.1. Transmission lines owned by a Transmission Owner that are operated at 200kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.

<sup>1</sup> “Clear line of sight” means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.



4.4.2. Qualified Facilities owned by applicable Generator Owners.

**5. Effective Dates:**

~~5.1. One calendar year from the date of adoption by the NERC Board of Trustees for Requirements 1 and 2.~~

~~5.2. Sixty calendar days from the date of adoption by the NERC Board of Trustees for Requirements 3 and 4.~~

**B. Requirements**

~~The Transmission~~ There are three effective dates associated with this implementation plan:

The first effective date applies to Transmission Owners.

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner become effective upon Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

The second effective date allows Generator Owners time to prepare a formal transmission vegetation management program as outlined in Requirement R1.

In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees' adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

The third effective date allows entities time to comply with Requirements R2, R3, and R4.

In those jurisdictions where regulatory approval is required, Requirements R2, R3, and R4 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R2, R3, and R4 become effective on the first day of the first calendar quarter two years following Board of Trustees' adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

**C.B. Requirements**

**R1.** Each applicable Transmission Owner or applicable Generator Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the applicable Transmission Owner's or applicable Generator Owner's objectives, practices, approved procedures, and work specifications<sup>2</sup>.

**R1.1.** The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of

<sup>2</sup> ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.

vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the applicable Transmission Owner's or applicable Generator Owner's transmission lines.

**R1.2.** ~~The~~ Each applicable Transmission Owner, or applicable Generator Owner in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the applicable Transmission Owner or applicable Generator Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.

**R1.2.1.** Clearance 1 — The applicable Transmission Owner or applicable Generator Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the applicable Transmission Owner or applicable Generator Owner plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.

**R1.2.2.** Clearance 2 — The applicable Transmission Owner or applicable Generator Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These applicable Transmission Owner-specific or applicable Generator Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.

**R1.2.2.1** Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.

**R1.2.2.2** Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.

**R1.3.** All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner or Generator Owner, to perform their duties.

**R1.4.** Each applicable Transmission Owner or applicable Generator Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the

transmission facilities when it identifies locations on the ROW where the Transmission Owner or applicable Generator Owner is restricted from attaining the clearances specified in Requirement 1.2.1.

- R1.5.** Each Transmission Owner or applicable Generator Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.

~~The~~[VRF – High]

- R2.** Each applicable Transmission Owner or applicable Generator Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each applicable Transmission Owner or applicable Generator Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.

~~The~~[VRF – High]

- R3.** Each applicable Transmission Owner or applicable Generator Owner shall report quarterly to its RRORegional Entity, or the RRO’sRegional Entity’s designee, sustained transmission line outages determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation.
- R3.1.** Multiple sustained 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.
- R3.2.** The applicable Transmission Owner or applicable Generator Owner is not required to report to the RRORegional Entity, or the RRO’sRegional Entity’s designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).
- R3.3.** The outage information provided by the applicable Transmission Owner or applicable Generator Owner to the RRORegional Entity, or the RRO’sRegional Entity’s designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

R3.4. An outage shall be categorized as one of the following:

R3.4.1. Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;

R3.4.2. Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;

R3.4.3. Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.

*[VRF – Lower]*

R4. The ~~RROR~~Regional Entity shall report the outage information provided to it by applicable Transmission ~~Owner's~~Owners or applicable Generator Owners, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the ~~RROR~~Regional Entity as a result of any of the reported outages.

*[VRF – Lower]*

## C. Measures

M1. ~~The~~Each applicable Transmission Owner or applicable Generator Owner has a documented TVMP, as identified in Requirement 1.

M1.1. ~~The~~Each applicable Transmission Owner or applicable Generator Owner has documentation that the applicable Transmission Owner or applicable Generator Owner performed the vegetation inspections as identified in Requirement 1.1.

M1.2. ~~The~~Each applicable Transmission Owner or applicable Generator Owner has documentation that describes the clearances identified in Requirement 1.2.

M1.3. ~~The~~Each applicable Transmission Owner or applicable Generator Owner has documentation that the personnel directly involved in the design and implementation of the applicable Transmission Owner's or applicable Generator Owner TVMP hold the qualifications identified by the Transmission Owner or applicable Generator Owner as required in Requirement 1.3.

M1.4. ~~The~~Each applicable Transmission Owner or applicable Generator Owner has documentation that it has identified any areas not meeting the applicable Transmission Owner's or applicable Generator Owner's standard for vegetation management and any mitigating measures the Transmission Owner or applicable Generator Owner has taken to address these deficiencies as identified in Requirement 1.4.

M1.5. ~~The~~Each applicable Transmission Owner or applicable Generator Owner has a documented process for the immediate communication of imminent threats by vegetation as identified in Requirement 1.5.

M2. ~~The~~Each applicable Transmission Owner or applicable Generator Owner has documentation that the Transmission Owner implemented the work plan identified in Requirement 2.

M3. ~~The~~Each applicable Transmission Owner or applicable Generator Owner has documentation that it has supplied quarterly outage reports to the ~~RROR~~Regional Entity, or the ~~RROR's~~Regional Entity's designee, as identified in Requirement 3.

M4. The ~~RROR~~Regional Entity has documentation that it provided quarterly outage reports to NERC as identified in Requirement 4.

## D. Compliance

### 1. Compliance Monitoring Process

**1.1. Compliance ~~Monitoring Responsibility~~ Enforcement Authority**

~~RRO~~  
~~NERC~~

The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the Compliance Enforcement Authority.

**1.2. Compliance Monitoring ~~Period~~ and ~~Reset~~ Enforcement Processes:**

~~One calendar Year~~  
Compliance Audit  
Self-Certification  
Spot Checking  
Compliance Investigation  
Self-Reporting  
Complaint

**1.3. Data Retention**

~~Five Years~~

The applicable Transmission Owner and applicable Generator Owner shall keep data or evidence to show compliance as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The applicable Transmission Owner and applicable Generator Owner shall retain evidence of Requirement 1, Measure 1, Requirement 2, Measure 2, and Requirement 3, Measure 3 from its last audit.

**1.4. Additional Compliance Information**

~~The Transmission Owner shall demonstrate compliance with the requirements of the NERC Reliability Standard FAC-003-1. The Transmission Owner shall submit a site audit every five years or more frequently to the compliance monitor to review documentation related to Reliability Standard FAC-003-1. Field audits of ROW vegetation conditions may be conducted if determined to be necessary by the compliance monitor.~~

The VSLs shown below were approved by FERC after FAC-003-1 was approved – only the changes associated with developing FAC-003-X are shown in

None.

**2. Violation Severity Levels**

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity did not include and keep current one of the four required elements of its TVMP, as directed	The responsible entity did not include and keep current two of the four required elements of its TVMP, as directed	The responsible entity did not include and keep current three of the four required elements of its TVMP, as directed	The responsible entity did not include and keep current all required elements of the TVMP, as directed by the

	by the requirement.	by the requirement.	by the requirement.	requirement.
R1.1	N/A	N/A	The applicable entity TVMP did not define a schedule, as directed by the requirement, or the type of ROW vegetation inspections, as directed by the requirement.	The applicable entity TVMP did not define a schedule, as directed by the requirement, nor the type of ROW vegetation inspections, as directed by the requirement.
R1.2	N/A	N/A	N/A	<p>The responsible entity, in its TVMP, failed to identify and document clearances between vegetation and any overhead, ungrounded supply conductors.</p> <p>OR</p> <p>The responsible entity, in its TVMP, failed to take into consideration transmission line voltage, or the effects of ambient temperature on conductor sag under maximum design loading, or the effects of wind velocities on conductor sway.</p> <p>OR</p> <p>The responsible entity, in its TVMP, failed to establish Clearance 1 or Clearance 2 values.</p>

R1.2.1	N/A	N/A	N/A	<p>The responsible entity failed to determine and document an appropriate clearance distance to be achieved at the time of transmission vegetation management work taking into account local conditions and the expected time frame in which the responsible entity expects to return for future vegetation management work.</p> <p>OR</p> <p>The responsible entity documented a Clearance 1 value that was smaller than its Clearance 2 value.</p>
R1.2.2	N/A	N/A	N/A	<p>The responsible entity failed to determine and document Clearance 2 values taking into account local conditions and the expected time frame in which the responsible entity expects to return for future vegetation management work.</p>
R1.2.2.1	N/A	N/A	N/A	<p>Where transmission system transient overvoltage factors were known, clearances were not derived from</p>



				Table 5, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.
R1.2.2.2	N/A	N/A	N/A	Where transmission system transient overvoltage factors are known, clearances were not derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.
R1.3	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, one of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, 5% or less of those persons did not hold appropriate qualifications and training to perform their duties.	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, two of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 5% up to (and including) 10% of those persons did not hold appropriate qualifications and training to perform their duties.	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, three of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 10% up to (and including) 15% of those persons did not hold appropriate qualifications and training to perform their duties.	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, more than three of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 15% of those persons did not hold appropriate qualifications and training to perform their duties.
R1.4	N/A	N/A	N/A	The responsible entity's TVMP does not include mitigation measures to achieve sufficient



				clearances where restrictions to the ROW are in effect.
R1.5	N/A	N/A	N/A	The responsible entity did not establish or did not document a process for the immediate communication of vegetation conditions that present an imminent threat of line outage, as directed by the requirement.
R2	The responsible entity did not meet one of the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	The responsible entity did not meet two of the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	The responsible entity did not meet the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	The responsible entity does not have an annual plan for vegetation management.  OR  The responsible entity has not implemented the annual plan for vegetation management.
R3	The responsible entity failed to provide a quarterly outage report, but did not experience any reportable outages.  OR  The responsible entity provided a quarterly report,	The responsible entity provided a quarterly report, but failed to include information required by R3.3.	The responsible entity provided a quarterly outage report, but failed to include a reportable Category 3 outage as described in R3.4.3.	The responsible entity experienced reportable outages but failed to provide a quarterly report.  OR  The responsible entity provided a quarterly outage report, but failed

	but failed to report in the manner specified by one or more of the following subcomponents of Requirement R3: R3.1 or R3.2.			to include a reportable Category 1 (as described in R3.4.1) or Category 2 outage (as described in R3.4.2).
R4	<del>Not applicable: N/A</del>	<del>Not applicable: N/A</del>	<del>N/A The RRO did not submit a quarterly report to NERC for a single quarter.</del>	<del>N/A The RRO did not submit a quarterly report to NERC for more than two consecutive quarters.</del>

E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
<del>Version 1</del>	TBA	<ol style="list-style-type: none"> <li>Added “Standard Development Roadmap.”</li> <li>Changed “60” to “Sixty” in section A, 5.2.</li> <li>Added “Proposed Effective Date: April 7, 2006” to footer.</li> <li>Added “Draft 3: November 17, 2005” to footer.</li> </ol>	01/20/06
<u>X</u>	<u>April 23, 2012</u>	<u>Made standard applicable to certain qualifying Generator Owners and brought overall standard format up to date; added VSLs approved by FERC</u>	<u>Revision under Project 2010-07</u>



## **Implementation Plan for FAC-003-X – Transmission Vegetation Management Program**

### **Prerequisite Approvals**

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

### **Revision to Sections of Approved Standards and Definitions**

There are no proposed revisions to requirements in other already approved standards. FAC-003-1 will be retired at midnight the day before FAC-003-X becomes effective.

There is one revised definition in the proposed standard:

**Right-of-Way:** A corridor of land on which electric lines may be located. The Transmission Owner or applicable Generator Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

The current glossary definition of Right-of-Way will be retired at midnight the day before FAC-003-X (and with it, the above definition of Right-of-Way) becomes effective.

### **Compliance with Standard**

There are no changes to the requirements applicable to Transmission Owners already in effect in FAC-003-1, and the expectation is that Transmission Owners will maintain their current state of compliance. Thus, the standard is effective for Transmission Owners upon approval, as detailed below.

The proposed changes to FAC-003-1 only address Generator Owner applicability and requirements (add Generator Owner to section 4 and add applicable Generator Owner to certain requirements). Therefore, this implementation plan only identifies a compliance timeframe for Generator Owners to which this standard will apply.

To reach compliance with the standard, a Generator Owner will have to perform a full review of as-built drawings and determine which generation interconnection Facilities require a Transmission Vegetation Management Plan (TVMP) and inspection as specified by NERC Reliability Standard FAC-003-X. In general, Generator Owners do not have staff that are qualified and experienced to create a TVMP and implement annual plans for vegetation management. Once a complete inventory is created, the Generator Owner will begin the process of gathering information for the TVMP. In instances where the generation interconnection Facilities are owned by a partnership, a majority or operating partner will need to obtain partnership approval to proceed with procurement of a TVMP expert, and later a tree trimming crew. Typically, a request for proposal to hire TVMP consultant is initiated, which could take several weeks in order to obtain sufficient bids (and also satisfy Sarbanes Oxley requirements). Once all bids have been received, a contract with a TVMP consultant is signed. At this point, the TVMP consultant and

Generator Owner staff will develop the TVMP, which needs to take into account local growth conditions, types of vegetation and other aspects required by FAC-003-X. Once the TVMP is developed, Generator Owner staff and the TVMP consultant will need to perform a Right-of-Way inspection, usually done using GPS, LIDAR and other tools by experienced and qualified staff.

Once a Right-of-Way inspection is completed and clearances are required, the Generator Owner will need to issue a request for proposal to hire a tree trimming crew that is qualified and experienced to perform required clearance trimming. Once all bids have been received, a contract with a tree trimming crew is signed. When the tree trimming crew is acquired, the crew will need to familiarize themselves with the entity's TVMP and required clearances. The Generator Owner will typically need to schedule any required outages in order for the tree trimming crew to perform the needed clearance trimming. This action would also include the implementation of the work plan. During scheduled outages, if required, the tree trimming crew will perform any required clearances and document the activities.

Another typical action is the Generator Owner establishing a system for maintaining TVMP-related activities, including maintenance of inspection and clearance documentation. On an ongoing basis, in addition to performing inspections and clearances as required by the entity's TVMP, the Generator Owner will need to ensure that the training and qualification requirements for the standard are met. The entity will also need to maintain documentation of all FAC-003-X activities for compliance period of one year to meet compliance with the standard.

Again, due to a typical lack of experience and qualifications required by FAC-003-X, compliance with this standard by a Generator Owner may take as long as two years – in part because many entities will have generator interconnection Facilities in various parts of the country which may require several instances of TVMPs and numerous Right-of-Way inspections.

### **Effective Date**

There are three effective dates associated with this implementation plan:

The first effective date applies to Transmission Owners.

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner become effective upon Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

The second effective date allows Generator Owners time to prepare a formal transmission vegetation management program as outlined in Requirement R1.

In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R1 becomes effective on the first day of the first calendar quarter one year following Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

The third effective date allows entities time to comply with Requirements R2, R3, and R4.

In those jurisdictions where regulatory approval is required, Requirements R2, R3, and R4 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R2, R3, and R4 become effective on the first day of the first calendar quarter two years following Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

## Implementation Plan for FAC-003-X – Transmission Vegetation Management Program

### Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

### Revision to Sections of Approved Standards and Definitions

There are no proposed revisions to requirements in other already approved standards. FAC-003-1 will be retired at midnight the day before FAC-003-X becomes effective.

There is one revised definition in the proposed standard:

**Right-of-Way:** A corridor of land on which electric lines may be located. The Transmission Owner or applicable Generator Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

The current glossary definition of Right-of-Way will be retired at midnight the day before FAC-003-X (and with it, the above definition of Right-of-Way) becomes effective.

### Compliance with Standard

There are no changes to the requirements applicable to Transmission Owners already in effect in FAC-003-1, and the expectation is that Transmission Owners will maintain their current state of compliance. Thus, the standard is effective for Transmission Owners upon approval, as detailed below.

The proposed changes to FAC-003-1 only address Generator Owner applicability and requirements (add Generator Owner to section 4-3 and add applicable Generator Owner to all-certain requirements). Therefore, this implementation plan only identifies a compliance timeframe for Generator Owners to which this standard will apply.

To reach compliance with the standard, a Generator Owner will have to perform a full review of as-built drawings and determine which generation interconnection Facilities require a Transmission Vegetation Management Plan (TVMP) and inspection as specified by NERC Reliability Standard FAC-003-X. In general, Generator Owners do not have staff that are qualified and experienced to create a TVMP and implement annual plans for vegetation management. Once a complete inventory is created, the Generator Owner will begin the process of gathering information for the TVMP. In instances where the generation interconnection Facilities are owned by a partnership, a majority or operating partner will need to obtain partnership approval to proceed with procurement of a TVMP expert, and later a tree trimming crew. Typically, a request for proposal to hire TVMP consultant is initiated, which could take several weeks in order to obtain sufficient bids (and also satisfy Sarbanes Oxley requirements). Once all bids have been received, a contract with a TVMP consultant is signed. At this point, the TVMP consultant and

Generator Owner staff will develop the TVMP, which needs to take into account local growth conditions, types of vegetation and other aspects required by FAC-003-X. Once the TVMP is developed, Generator Owner staff and the TVMP consultant will need to perform a Right-of-Way inspection, usually done using GPS, LIDAR and other tools by experienced and qualified staff.

Once a Right-of-Way inspection is completed and clearances are required, the Generator Owner will need to issue a request for proposal to hire a tree trimming crew that is qualified and experienced to perform required clearance trimming. Once all bids have been received, a contract with a tree trimming crew is signed. When the tree trimming crew is acquired, the crew will need to familiarize themselves with the entity's TVMP and required clearances. The Generator Owner will typically need to schedule any required outages in order for the tree trimming crew to perform the needed clearance trimming. This action would also include the implementation of the work plan. During scheduled outages, if required, the tree trimming crew will perform any required clearances and document the activities.

Another typical action is the Generator Owner establishing a system for maintaining TVMP-related activities, including maintenance of inspection and clearance documentation. On an ongoing basis, in addition to performing inspections and clearances as required by the entity's TVMP, the Generator Owner will need to ensure that the training and qualification requirements for the standard are met. The entity will also need to maintain documentation of all FAC-003-X activities for compliance period of one year to meet compliance with the standard.

Again, due to a typical lack of experience and qualifications required by FAC-003-X, compliance with this standard by a Generator Owner may take as long as two years – in part because many entities will have generator interconnection Facilities in various parts of the country which may require several instances of TVMPs and numerous Right-of-Way inspections.

### **Effective Date**

There are three effective dates associated with this implementation plan:

The first effective date applies to Transmission Owners.

In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner become effective upon Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

The second effective date allows Generator Owners time to prepare a formal transmission vegetation management program as outlined in Requirement R1.



In those jurisdictions where regulatory approval is required, Requirement R1 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement ~~R3~~R1 becomes effective on the first day of the first calendar quarter one year following Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

The third effective date allows entities time to comply with Requirements R2, R3, and R4.

In those jurisdictions where regulatory approval is required, Requirements R2, R3, and R4 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R2, R3, and R4 become effective on the first day of the first calendar quarter two years following Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

### Effective Dates

There are two effective dates associated with this standard.

The first effective date allows Generator Owners time to develop documented maintenance strategies or procedures or processes or specifications as outlined in Requirement R3.

In those jurisdictions where regulatory approval is required, Requirement R3 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

The second effective date allows entities time to comply with Requirements R1, R2, R4, R5, R6, and R7.

In those jurisdictions where regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 become effective on the first day of the first calendar quarter two years following Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.
2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.
3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.

4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.
  
5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

Version History

<b>Version</b>	<b>Date</b>	<b>Action</b>	<b>Change Tracking</b>
3	September 29, 2011	Using the latest draft of FAC-003-2 from the Project 2007-07 SDT, modified proposed definitions and Applicability to include Generator Owners of a certain length.	Revision under Project 2010-07

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

### **Right-of-Way (ROW)**

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria.

The current glossary definition of this NERC term is modified to address the issues set forth in Paragraph 734 of FERC Order 693.

The Project 2010-07 team further modified that proposed definition to include applicable Generator Owners.

### **Vegetation Inspection**

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the applicable Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.

The Project 2010-07 team further modified that proposed definition to include applicable Generator Owners.

Current definition of Vegetation Inspection:  
The systematic examination of a transmission corridor to document vegetation conditions.

### **Minimum Vegetation Clearance Distance (MVCD)**

The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

*When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.*

FAC-003-2 was developed under Project 2007-07. The standard was balloted and adopted by the NERC Board of Trustees, but the Project 2010-07 drafting team does not want to assume that FAC-003-2 will be approved by FERC and other governmental authorities. Thus, the Project 2010-07 drafting team has developed two sets of proposed changes: one to this version, FAC-003-2, the version developed by the Project 2007-07 team and adopted by NERC's Board of Trustees, and one to FAC-003-1, the current FERC-approved version of the standard.

## A. Introduction

1. **Title:** Transmission Vegetation Management
2. **Number:** FAC-003-3
3. **Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

### 4. Applicability

#### 4.1. Functional Entities:

##### 4.1.1. Applicable Transmission Owners

4.1.1.1 Transmission Owners that own Transmission Facilities defined in 4.2.

##### 4.1.2 Applicable Generator Owners

4.1.2.1 Generator Owners that own generation Facilities defined in 4.3

- 4.2. **Transmission Facilities:** Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal<sup>1</sup>, state, provincial, public, private, or tribal entities:

4.2. 1 Each overhead transmission line operated at 200kV or higher.

**Rationale:** The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

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<sup>1</sup> EPAAct 2005 section 1211c: “Access approvals by Federal agencies.”

**4.2.2** Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.

**4.2.3** Each overhead transmission line operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

**4.2.4** Each overhead transmission line identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

**4.3. Generation Facilities:** Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal<sup>2</sup>, state, provincial, public, private, or tribal entities:

**4.3.1** Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner’s Facility or (2) do not have a clear line of sight<sup>3</sup> from the generating station switchyard fence to the point of interconnection with a Transmission Owner’s Facility and are:

Within the text of NERC Reliability Standard FAC-003-3, “transmission line(s) and “applicable line(s) can also refer to the generation Facilities as referenced in 4.3 and its subsections.

**4.3.1.1** Operated at 200kV or higher; or

**4.3.1.2** Operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator; or

**4.3.1.3** Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

Enforcement:

The Requirements within a Reliability Standard govern and will be enforced. The Requirements within a Reliability Standard define what an entity must do to be compliant and binds an entity to certain obligations of performance under Section 215 of the Federal Power Act. Compliance will in all cases be measured by determining whether a party met or failed to meet the Reliability Standard Requirement given the specific facts and circumstances of its use, ownership or operation of the bulk power system.

Measures provide guidance on assessing non-compliance with the Requirements. Measures are the evidence that could be presented to demonstrate compliance with a Reliability Standard Requirement and are not intended to contain the quantitative metrics for determining satisfactory performance nor to limit how an entity may demonstrate compliance if valid alternatives to

<sup>2</sup> EPAAct 2005 section 1211c: “Access approvals by Federal agencies.”

<sup>3</sup> “Clear line of sight” means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.

demonstrating compliance are available in a specific case. A Reliability Standard may be enforced in the absence of specified Measures.

Entities must comply with the “Compliance” section in its entirety, including the Administrative Procedure that sets forth, among other things, reporting requirements.

The “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” are provided for informational purposes. They are designed to convey guidance from NERC’s various activities. The “Guideline and Technical Basis” section and text boxes with “Examples” and “Rationale” are not intended to establish new Requirements under NERC’s Reliability Standards or to modify the Requirements in any existing NERC Reliability Standard. Implementation of the “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” is not a substitute for compliance with Requirements in NERC’s Reliability Standards.”

## **5. Background:**

This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

- a) Performance-based — defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome?*
- b) Risk-based — preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?*
- c) Competency-based — defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?*

The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constraints such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

For this standard, the requirements have been developed as follows:

Performance-based: Requirements 1 and 2

Competency-based: Requirement 3

Risk-based: Requirements 4, 5, 6 and 7

R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term “public lands” includes municipal lands, village lands, city lands, and a host of other governmental entities.

This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.



This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

## B. Requirements and Measures

**R1.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below<sup>4</sup> [*Violation Risk Factor: High*] [*Time Horizon: Real-time*]:

1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage<sup>5</sup>,
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage<sup>6</sup>,
3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage<sup>4</sup>,
4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage<sup>4</sup>.

**M1.** Each applicable Transmission Owner

### Rationale for R1 and R2:

Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable Transmission Owner's or applicable Generator Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.
2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

<sup>4</sup> This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.

<sup>5</sup> If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

<sup>6</sup> Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

- R2.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below<sup>2</sup> [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time*]:
1. An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage<sup>3</sup>,
  2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage<sup>4</sup>,
  3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage<sup>4</sup>,
  4. An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage<sup>4</sup>
- M2.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)

**R3.** Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following:

**3.1** Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;

**3.2** Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning];

**Rationale**

The documentation provides a basis for evaluating the competency of the applicable Transmission Owner’s or applicable Generator Owner’s vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions. See Figure

**M3.** The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

**R4.** Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment [Violation Risk Factor: Medium] [Time Horizon: Real-time].

**Rationale**

This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

**M4.** Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

**R5.** When a applicable Transmission Owner and applicable Generator Owner is constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

**Rationale**

Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

**M5.** Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

**Rationale**

Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could

**R6.** Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW<sup>7</sup> [*Violation Risk Factor:*

<sup>7</sup> When the applicable Transmission Owner or applicable Generator Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.

*Medium*] [*Time Horizon: Operations Planning*].

**M6.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

**R7.** Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan

**Rationale**

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

(measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

- Change in expected growth rate/ environmental factors
- Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner<sup>8</sup>
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Emerging technologies

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<sup>8</sup> Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.

- M7.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records.  
(R7)

## **C. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1 Compliance Enforcement Authority**

The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

For NERC, a third-party monitor without vested interest in the outcome for NERC shall serve as the Compliance Enforcement Authority.

#### **1.2 Regional Entity Evidence Retention**

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, Measures M1, M2, M3, M5, M6 and M7 for three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### **1.3 Compliance Monitoring and Enforcement Processes:**

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaint

Periodic Data Submittal

#### **1.4 Additional Compliance Information**

***Periodic Data Submittal:*** The applicable Transmission Owner and applicable Generator Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified as an element of an



IROL or Major WECC Transfer Path, blowing together from within the ROW.

- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

**Table of Compliance Elements**

R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Real-time	High			<p>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.</p>	<p>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following:</p> <ul style="list-style-type: none"> <li>• A fall-in from inside the active transmission line ROW</li> <li>• Blowing together of applicable lines and vegetation located inside the active transmission line ROW</li> <li>• A grow-in</li> </ul>
R2	Real-time	Medium			<p>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.</p>	<p>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following:</p> <ul style="list-style-type: none"> <li>• A fall-in from inside the active transmission line</li> </ul>

						<p>ROW</p> <ul style="list-style-type: none"> <li>Blowing together of applicable lines and vegetation located inside the active transmission line ROW</li> <li>A grow-in</li> </ul>
R3	Long-Term Planning	Lower		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity's applicable lines. (Requirement R3, Part 3.2)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines. Requirement R3, Part 3.1)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity's applicable lines.
R4	Real-time	Medium			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5	Operations Planning	Medium				The responsible entity did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6	Operations	Medium	The responsible entity	The responsible entity failed	The responsible entity failed to	The responsible entity failed to

	Planning		failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7	Operations Planning	Medium	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Differences

None.

E. Interpretations

None.

F. Associated Documents

Guideline and Technical Basis (attached).

## Guideline and Technical Basis

### Effective dates:

The first two sentences of the Effective Dates section is standard language used in most NERC standards to cover the general effective date and is sufficient to cover the vast majority of situations. Five special cases are needed to cover effective dates for individual lines which undergo transitions after the general effective date. These special cases cover the effective dates for those lines which are initially becoming subject to the standard, those lines which are changing their applicability within the standard, and those lines which are changing in a manner that removes their applicability to the standard.

Case 1 is needed because the Planning Coordinators may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2011 may identify a line to have that designation beginning in PY 2021, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. The table below has some explanatory examples of the application.

<u>Date that Planning Study is completed</u>	<u>PY the line will become an IROL element</u>	<u>Date 1</u>	<u>Date 2</u>	<u>Effective Date The latter of Date 1 or Date 2</u>
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Case 2 is needed because a line operating below 200kV designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Case 3 is needed because a line operating at 200 kV or above that once was designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network. Such changes result in the need to apply R1 to that line until that date is reached and then to apply R2 to that line thereafter.

Case 4 is needed because an existing line that is to be operated at 200 kV or above can be acquired by an applicable Transmission Owner or applicable Generator Owner from a third party

such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network which will thereafter make the line subject to the standard.

Case 5 is needed because an existing line that is operated below 200 kV can be acquired by an applicable Transmission Owner or applicable Generator Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network. In this special case the line upon acquisition was designated as an element of an Interconnection Reliability Operating Limit (IROL) or an element of a Major WECC Transfer Path.

### **Defined Terms:**

#### **Explanation for revising the definition of ROW:**

The current NERC glossary definition of Right of Way has been modified to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This modified definition represents a slight but significant departure from the strict legal definition of “right of way” in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the revised definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

The Project 2010-07 team further modified that proposed definition to include applicable Generator Owners.

#### **Explanation for revising the definition of Vegetation Inspections:**

The current glossary definition of this NERC term is being modified to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

The Project 2010-07 team further modified that proposed definition to include applicable Generator Owners.

**Explanation of the definition of the MVCD:**

The MVCD is a calculated minimum distance that is derived from the Gallet Equations. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 below provides MVCD values for various voltages and altitudes. Details of the equations and an example calculation are provided in Appendix 1 of the Technical Reference Document.

**Requirements R1 and R2:**

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each applicable Transmission Owner or applicable Generator Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element of an IROL or Major WECC Transfer Path. R2 is applicable to all other lines that are not elements of IROLs, and not elements of Major WECC Transfer Paths.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations as described more fully in the Technical Reference document.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting

in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will prevent transmission outages.

If the applicable Transmission Owner or applicable Generator Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

### **Requirement R3:**

R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable Transmission Owner or applicable Generator Owner uses for vegetation management.

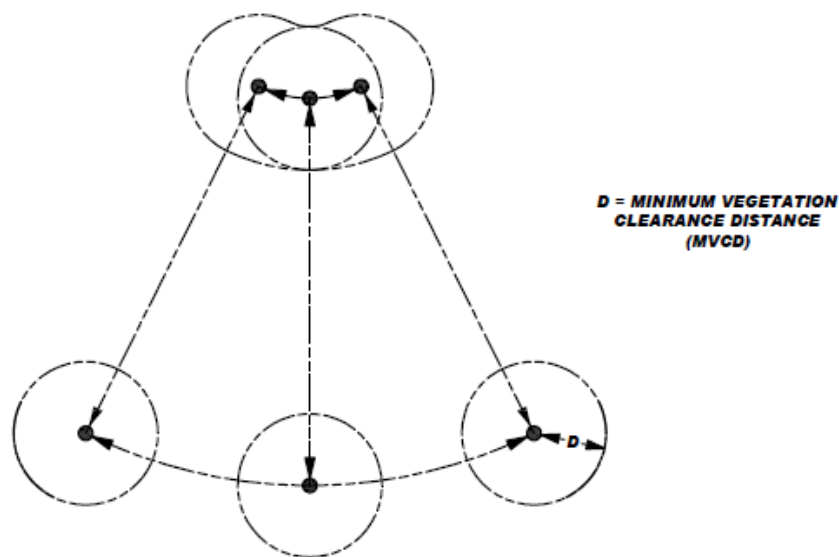
An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an applicable Transmission Owner or applicable Generator Owner chooses to use will generally contain the following elements:



1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below. In the Technical Reference document more figures and explanations of conductor dynamics are provided.



**Figure 1**

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

#### **Requirement R4:**

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled),

crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner or applicable Generator Owner employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

**Requirement R5:**

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the applicable Transmission Owner or applicable Generator Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The applicable Transmission Owner or applicable Generator Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

#### **Requirement R6:**

R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner's ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission Owner or applicable Generator Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be  $100/2000 = 0.05$  or 5%. The "Low VSL" for R6 would apply in this example.

#### **Requirement R7:**

R7 is a risk-based requirement. The applicable Transmission Owner or applicable Generator Owner is required to complete its annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a “span-by-span”, or even a “line-by-line” detailed description of all work to be performed. It is only intended to require that the applicable Transmission Owner or applicable Generator Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

For example, when an applicable Transmission Owner or applicable Generator Owner identifies 1,000 miles of applicable transmission lines to be completed in the applicable Transmission Owner’s or applicable Generator Owner’s annual plan, the applicable Transmission Owner or applicable Generator Owner will be responsible completing those identified miles. If a applicable Transmission Owner or applicable Generator Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be:  $1000 - 100$  (deferred miles) = 900 modified annual plan, or  $900 / 900 = 100\%$  completed annual miles. If an applicable Transmission Owner or applicable Generator Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be:  $1000 - 875 = 125$  miles failed to complete then,  $125$  miles (not completed) /  $1000$  total annual plan miles =  $12.5\%$  failed to complete.

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner’s or applicable Generator Owner’s system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.

In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner’s or applicable Generator Owner’s easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits

may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

**FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)<sup>9</sup>  
For Alternating Current Voltages (feet)**

( AC ) Nominal System Voltage (KV)	( AC ) Maximum System Voltage (kV) <sup>10</sup>	MVCD (feet)	MVCD (feet)	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet
		Over sea level up to 500 ft	Over 500 ft up to 1000 ft	Over 1000 ft up to 2000 ft	Over 2000 ft up to 3000 ft	Over 3000 ft up to 4000 ft	Over 4000 ft up to 5000 ft	Over 5000 ft up to 6000 ft	Over 6000 ft up to 7000 ft	Over 7000 ft up to 8000 ft	Over 8000 ft up to 9000 ft	Over 9000 ft up to 10000 ft	Over 10000 ft up to 11000 ft
765	800	8.2ft	8.33ft	8.61ft	8.89ft	9.17ft	9.45ft	9.73ft	10.01ft	10.29ft	10.57ft	10.85ft	11.13ft
500	550	5.15ft	5.25ft	5.45ft	5.66ft	5.86ft	6.07ft	6.28ft	6.49ft	6.7ft	6.92ft	7.13ft	7.35ft
345	362	3.19ft	3.26ft	3.39ft	3.53ft	3.67ft	3.82ft	3.97ft	4.12ft	4.27ft	4.43ft	4.58ft	4.74ft
287	302	3.88ft	3.96ft	4.12ft	4.29ft	4.45ft	4.62ft	4.79ft	4.97ft	5.14ft	5.32ft	5.50ft	5.68ft
230	242	3.03ft	3.09ft	3.22ft	3.36ft	3.49ft	3.63ft	3.78ft	3.92ft	4.07ft	4.22ft	4.37ft	4.53ft
161*	169	2.05ft	2.09ft	2.19ft	2.28ft	2.38ft	2.48ft	2.58ft	2.69ft	2.8ft	2.91ft	3.03ft	3.14ft
138*	145	1.74ft	1.78ft	1.86ft	1.94ft	2.03ft	2.12ft	2.21ft	2.3ft	2.4ft	2.49ft	2.59ft	2.7ft
115*	121	1.44ft	1.47ft	1.54ft	1.61ft	1.68ft	1.75ft	1.83ft	1.91ft	1.99ft	2.07ft	2.16ft	2.25ft
88*	100	1.18ft	1.21ft	1.26ft	1.32ft	1.38ft	1.44ft	1.5ft	1.57ft	1.64ft	1.71ft	1.78ft	1.86ft
69*	72	0.84ft	0.86ft	0.90ft	0.94ft	0.99ft	1.03ft	1.08ft	1.13ft	1.18ft	1.23ft	1.28ft	1.34ft

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

<sup>9</sup> The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

<sup>10</sup> Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

**TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)<sup>7</sup>  
For Alternating Current Voltages (meters)**

( AC ) Nominal System Voltage (KV)	( AC ) Maximum System Voltage (kV) <sup>8</sup>	MVCD meters  Over sea level up to 152.4 m	MVCD meters  Over 152.4 m up to 304.8 m	MVCD meters  Over 304.8 m up to 609.6m	MVCD meters  Over 609.6m up to 914.4m	MVCD meters  Over 914.4m up to 1219.2m	MVCD meters  Over 1219.2m up to 1524m	MVCD meters  Over 1524 m up to 1828.8 m	MVCD meters  Over 1828.8m up to 2133.6m	MVCD meters  Over 2133.6m up to 2438.4m	MVCD meters  Over 2438.4m up to 2743.2m	MVCD meters  Over 2743.2m up to 3048m	MVCD meters  Over 3048m up to 3352.8m
765	800	2.49m	2.54m	2.62m	2.71m	2.80m	2.88m	2.97m	3.05m	3.14m	3.22m	3.31m	3.39m
500	550	1.57m	1.6m	1.66m	1.73m	1.79m	1.85m	1.91m	1.98m	2.04m	2.11m	2.17m	2.24m
345	362	0.97m	0.99m	1.03m	1.08m	1.12m	1.16m	1.21m	1.26m	1.30m	1.35m	1.40m	1.44m
287	302	1.18m	0.88m	1.26m	1.31m	1.36m	1.41m	1.46m	1.51m	1.57m	1.62m	1.68m	1.73m
230	242	0.92m	0.94m	0.98m	1.02m	1.06m	1.11m	1.15m	1.19m	1.24m	1.29m	1.33m	1.38m
161*	169	0.62m	0.64m	0.67m	0.69m	0.73m	0.76m	0.79m	0.82m	0.85m	0.89m	0.92m	0.96m
138*	145	0.53m	0.54m	0.57m	0.59m	0.62m	0.65m	0.67m	0.70m	0.73m	0.76m	0.79m	0.82m
115*	121	0.44m	0.45m	0.47m	0.49m	0.51m	0.53m	0.56m	0.58m	0.61m	0.63m	0.66m	0.69m
88*	100	0.36m	0.37m	0.38m	0.40m	0.42m	0.44m	0.46m	0.48m	0.50m	0.52m	0.54m	0.57m
69*	72	0.26m	0.26m	0.27m	0.29m	0.30m	0.31m	0.33m	0.34m	0.36m	0.37m	0.39m	0.41m

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

**TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)<sup>7</sup>**  
 For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)
	Over sea level up to 500 ft	Over 500 ft up to 1000 ft	Over 1000 ft up to 2000 ft	Over 2000 ft up to 3000 ft	Over 3000 ft up to 4000 ft	Over 4000 ft up to 5000 ft	Over 5000 ft up to 6000 ft	Over 6000 ft up to 7000 ft	Over 7000 ft up to 8000 ft	Over 8000 ft up to 9000 ft	Over 9000 ft up to 10000 ft	Over 10000 ft up to 11000 ft
	(Over sea level up to 152.4 m)	(Over 152.4 m up to 304.8 m)	(Over 304.8 m up to 609.6m)	(Over 609.6m up to 914.4m)	(Over 914.4m up to 1219.2m)	(Over 1219.2m up to 1524m)	(Over 1524 m up to 1828.8 m)	(Over 1828.8m up to 2133.6m)	(Over 2133.6m up to 2438.4m)	(Over 2438.4m up to 2743.2m)	(Over 2743.2m up to 3048m)	(Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)



**Notes:**

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet Equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 uses the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-01 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines, as such, are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-

service ac line is approximately 2.0 per unit. This value is a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below is considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit is considered a realistic maximum.

The Gallet Equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet Equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

While EPRI is currently trying to establish empirical data for spark-over distances to live vegetation, there are no spark-over formulas currently derived expressly for vegetation to conductor minimum distances. Therefore the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

**Comparison of spark-over distances computed using Gallet wet equations vs.  
IEEE 516-2003 MAID distances**

<b>( AC ) Nom System Voltage (kV)</b>	<b>( AC ) Max System Voltage (kV)</b>	<b>Transient Over-voltage Factor (T)</b>	<b>Clearance (ft.) Gallet (wet) @ Alt. 3000 feet</b>	<b>Table 7 (Table D.5 for feet) IEEE 516-2003 MAID (ft) @ Alt. 3000 feet</b>
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

## Effective Dates

There are two effective dates associated with this standard.

The first effective date allows Generator Owners time to develop documented maintenance strategies or procedures or processes or specifications as outlined in Requirement R3.

In those jurisdictions where regulatory approval is required, Requirement R3 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

The second effective date allows entities time to comply with Requirements R1, R2, R4, R5, R6, and R7.

In those jurisdictions where regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 become effective on the first day of the first calendar quarter two years following Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.
2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.
3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.

4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.
  
5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

### Version History

<b>Version</b>	<b>Date</b>	<b>Action</b>	<b>Change Tracking</b>
3	September 29, 2011	Using the latest draft of FAC-003-2 from the Project 2007-07 SDT, modified proposed definitions and Applicability to include Generator Owners of a certain length.	Revision under Project 2010-07

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

### **Right-of-Way (ROW)**

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission

Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria.

The current glossary definition of this NERC term is modified to address the issues set forth in Paragraph 734 of FERC Order 693.

The Project 2010-07 team further modified that proposed definition to include applicable Generator Owners.

### **Vegetation Inspection**

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the applicable Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.

The Project 2010-07 team further modified that proposed definition to include applicable Generator Owners.

Current definition of Vegetation Inspection:  
The systematic examination of a transmission corridor to document vegetation conditions.

### **Minimum Vegetation Clearance Distance (MVCD)**

The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

*When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.*

FAC-003-2 was developed under Project 2007-07. The standard was balloted and adopted by the NERC Board of Trustees, but the Project 2010-07 drafting team does not want to assume that FAC-003-2 will be approved by FERC and other governmental authorities. Thus, the Project 2010-07 drafting team has developed two sets of proposed changes: one to this version, FAC-003-2, the version developed by the Project 2007-07 team and adopted by NERC’s Board of Trustees, and one to FAC-003-1, the current FERC-approved version of the standard.

## A. Introduction

1. **Title:** Transmission Vegetation Management
2. **Number:** FAC-003-3
3. **Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

## 4. Applicability

### 4.1. Functional Entities:

#### 4.1.1. Applicable Transmission Owners

4.1.1.1 Transmission Owners that own Transmission Facilities defined in 4.2.

#### 4.1.2 Applicable Generator Owners

4.1.2.1 Generator Owners that own generation Facilities defined in 4.3

- 4.2. **Transmission Facilities:** Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal<sup>1</sup>, state, provincial, public, private, or tribal entities:

4.2. 1 Each overhead transmission line operated at 200kV or higher.

**Rationale:** The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

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<sup>1</sup> EPAAct 2005 section 1211c: “Access approvals by Federal agencies.”

**4.2.2** Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.

**4.2.3** Each overhead transmission line operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

**4.2.4** Each overhead transmission line identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

**4.3. Generation Facilities:** Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal<sup>2</sup>, state, provincial, public, private, or tribal entities:

**4.3.1** Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner’s Facility or (2) do not have a clear line of sight<sup>3</sup> from the generating station switchyard fence to the point of interconnection with a Transmission Owner’s Facility and are:

Within the text of NERC Reliability Standard FAC-003-3, “transmission line(s) and “applicable line(s) can also refer to the generation Facilities as referenced in 4.3 and its subsections.

**4.3.1.1** Operated at 200kV or higher; or

**4.3.1.2** Operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator; or

**4.3.1.3** Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

Enforcement:

The Requirements within a Reliability Standard govern and will be enforced. The Requirements within a Reliability Standard define what an entity must do to be compliant and binds an entity to certain obligations of performance under Section 215 of the Federal Power Act. Compliance will in all cases be measured by determining whether a party met or failed to meet the Reliability Standard Requirement given the specific facts and circumstances of its use, ownership or operation of the bulk power system.

Measures provide guidance on assessing non-compliance with the Requirements. Measures are the evidence that could be presented to demonstrate compliance with a Reliability Standard Requirement and are not intended to contain the quantitative metrics for determining satisfactory performance nor to limit how an entity may demonstrate compliance if valid alternatives to

<sup>2</sup> EPAAct 2005 section 1211c: “Access approvals by Federal agencies.”

<sup>3</sup> “Clear line of sight” means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.



demonstrating compliance are available in a specific case. A Reliability Standard may be enforced in the absence of specified Measures.

Entities must comply with the “Compliance” section in its entirety, including the Administrative Procedure that sets forth, among other things, reporting requirements.

The “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” are provided for informational purposes. They are designed to convey guidance from NERC’s various activities. The “Guideline and Technical Basis” section and text boxes with “Examples” and “Rationale” are not intended to establish new Requirements under NERC’s Reliability Standards or to modify the Requirements in any existing NERC Reliability Standard. Implementation of the “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” is not a substitute for compliance with Requirements in NERC’s Reliability Standards.”

## 5. Background:

This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

- a) Performance-based — defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome?*
- b) Risk-based — preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?*
- c) Competency-based — defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?*

The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constraints such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

For this standard, the requirements have been developed as follows:

Performance-based: Requirements 1 and 2

Competency-based: Requirement 3

Risk-based: Requirements 4, 5, 6 and 7

R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term “public lands” includes municipal lands, village lands, city lands, and a host of other governmental entities.

This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

## B. Requirements and Measures

**R1.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below<sup>4</sup> [*Violation Risk Factor: High*] [*Time Horizon: Real-time*]:

1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage<sup>5</sup>,
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage<sup>6</sup>,
3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage<sup>4</sup>,
4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage<sup>4</sup>.

**M1.** Each applicable Transmission Owner

### Rationale for R1 and R2:

Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable Transmission Owner's or applicable Generator Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.
2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

<sup>4</sup> This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.

<sup>5</sup> If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

<sup>6</sup> Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

- R2.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below<sup>2</sup> [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time*]:
1. An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage<sup>3</sup>,
  2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage<sup>4</sup>,
  3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage<sup>4</sup>,
  4. An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage<sup>4</sup>

- M2.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)

**R3.** Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following:

- 3.1** Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;
- 3.2** Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

*[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]:*

**Rationale**

The documentation provides a basis for evaluating the competency of the applicable Transmission Owner’s or applicable Generator Owner’s vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions. See Figure 1 for an illustration of possible conductor locations.

**M3.** The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

**R4.** Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment *[Violation Risk Factor: Medium] [Time Horizon: Real-time]*.

**Rationale**

This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

**M4.** Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

**R5.** When a applicable Transmission Owner and applicable Generator Owner is constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

**Rationale**

Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

**M5.** Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

**R6.** Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW<sup>7</sup> [*Violation Risk Factor:*

**Rationale**

Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could

<sup>7</sup> When the applicable Transmission Owner or applicable Generator Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.



*Medium*] [*Time Horizon: Operations Planning*].

**M6.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

**R7.** Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan

**Rationale**

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

(measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

- Change in expected growth rate/ environmental factors
- Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner<sup>8</sup>
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Emerging technologies

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<sup>8</sup> Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.



- M7.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records.  
(R7)

## C. Compliance

### 1. Compliance Monitoring Process

#### **1.1 Compliance Enforcement Authority**

The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

For NERC, a third-party monitor without vested interest in the outcome for NERC shall serve as the Compliance Enforcement Authority.

#### **1.1.2 Regional Entity Evidence Retention**

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, Measures M1, M2, M3, M5, M6 and M7 for three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### **1.21.3 Compliance Monitoring and Enforcement Processes:**

Compliance Audit

Self-Certification

Spot Checking  
Compliance Violation Investigation  
Self-Reporting  
Complaint  
Periodic Data Submittal

### **1.31.4 Additional Compliance Information**

***Periodic Data Submittal:*** The applicable Transmission Owner and applicable Generator Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified as an element of an

IROL or Major WECC Transfer Path, blowing together from within the ROW.

- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

**Table of Compliance Elements**

R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Real-time	High			<p>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.</p>	<p>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following:</p> <ul style="list-style-type: none"> <li>• A fall-in from inside the active transmission line ROW</li> <li>• Blowing together of applicable lines and vegetation located inside the active transmission line ROW</li> <li>• A grow-in</li> </ul>
R2	Real-time	Medium			<p>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.</p>	<p>The <del>Transmission</del> <u>Ownerresponsible entity</u> failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following:</p> <ul style="list-style-type: none"> <li>• A fall-in from inside the</li> </ul>

						<p>active transmission line ROW</p> <ul style="list-style-type: none"> <li>• Blowing together of applicable lines and vegetation located inside the active transmission line ROW</li> <li>• A grow-in</li> </ul>
R3	Long-Term Planning	Lower		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity’s applicable lines. (Requirement R3, Part 3.2)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity’s applicable lines. Requirement R3, Part 3.1)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity’s applicable lines.
R4	Real-time	Medium			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5	Operations Planning	Medium				The responsible entity did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.

R6	Operations Planning	Medium	The responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7	Operations Planning	Medium	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Differences

None.

E. Interpretations

None.

F. Associated Documents

Guideline and Technical Basis (attached).

## Guideline and Technical Basis

### Effective dates:

The first two sentences of the Effective Dates section is standard language used in most NERC standards to cover the general effective date and is sufficient to cover the vast majority of situations. Five special cases are needed to cover effective dates for individual lines which undergo transitions after the general effective date. These special cases cover the effective dates for those lines which are initially becoming subject to the standard, those lines which are changing their applicability within the standard, and those lines which are changing in a manner that removes their applicability to the standard.

Case 1 is needed because the Planning Coordinators may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2011 may identify a line to have that designation beginning in PY 2021, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. The table below has some explanatory examples of the application.

<u>Date that Planning Study is completed</u>	<u>PY the line will become an IROL element</u>	<u>Date 1</u>	<u>Date 2</u>	<u>Effective Date The latter of Date 1 or Date 2</u>
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Case 2 is needed because a line operating below 200kV designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Case 3 is needed because a line operating at 200 kV or above that once was designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network. Such changes result in the need to apply R1 to that line until that date is reached and then to apply R2 to that line thereafter.

Case 4 is needed because an existing line that is to be operated at 200 kV or above can be acquired by an applicable Transmission Owner or applicable Generator Owner from a third party

such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network which will thereafter make the line subject to the standard.

Case 5 is needed because an existing line that is operated below 200 kV can be acquired by an applicable Transmission Owner or applicable Generator Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network. In this special case the line upon acquisition was designated as an element of an Interconnection Reliability Operating Limit (IROL) or an element of a Major WECC Transfer Path.

### **Defined Terms:**

#### **Explanation for revising the definition of ROW:**

The current NERC glossary definition of Right of Way has been modified to include Generator Owners and to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This modified definition represents a slight but significant departure from the strict legal definition of “right of way” in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the revised definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

#### **Explanation for revising the definition of Vegetation Inspections:**

The current glossary definition of this NERC term is being modified to include Generator Owners and to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

#### **Explanation of the definition of the MVCD:**

The MVCD is a calculated minimum distance that is derived from the Gallet Equations. This is a method of calculating a flash over distance that has been used in the design of high voltage



transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 below provides MVCD values for various voltages and altitudes. Details of the equations and an example calculation are provided in Appendix 1 of the Technical Reference Document.

**Requirements R1 and R2:**

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each applicable Transmission Owner or applicable Generator Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element of an IROL or Major WECC Transfer Path. R2 is applicable to all other lines that are not elements of IROLs, and not elements of Major WECC Transfer Paths.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations as described more fully in the Technical Reference document.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will prevent transmission outages.

If the applicable Transmission Owner or applicable Generator Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

### **Requirement R3:**

R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable Transmission Owner or applicable Generator Owner uses for vegetation management.

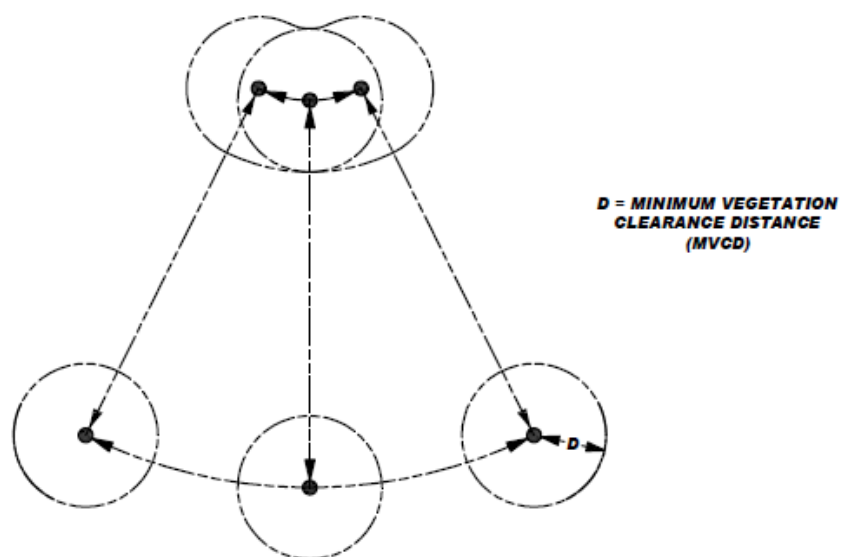
An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an applicable Transmission Owner or applicable Generator Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*

3. a stated *Vegetation Inspection frequency*
4. an *annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below. In the Technical Reference document more figures and explanations of conductor dynamics are provided.



**Figure 1**

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

**Requirement R4:**

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner or applicable Generator Owner employee who

personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

**Requirement R5:**

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the applicable Transmission Owner or applicable Generator Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The applicable Transmission Owner or applicable Generator Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

**Requirement R6:**

R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner's ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission Owner or applicable Generator Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be  $100/2000 = 0.05$  or 5%. The "Low VSL" for R6 would apply in this example.

**Requirement R7:**

R7 is a risk-based requirement. The applicable Transmission Owner or applicable Generator Owner is required to complete its an annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to

necessarily require a “span-by-span”, or even a “line-by-line” detailed description of all work to be performed. It is only intended to require that the applicable Transmission Owner or applicable Generator Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

For example, when an applicable Transmission Owner or applicable Generator Owner identifies 1,000 miles of applicable transmission lines to be completed in the applicable Transmission Owner’s or applicable Generator Owner’s annual plan, the applicable Transmission Owner or applicable Generator Owner will be responsible completing those identified miles. If a applicable Transmission Owner or applicable Generator Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be:  $1000 - 100$  (deferred miles) = 900 modified annual plan, or  $900 / 900 = 100\%$  completed annual miles. If an applicable Transmission Owner or applicable Generator Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be:  $1000 - 875 = 125$  miles failed to complete then,  $125$  miles (not completed) /  $1000$  total annual plan miles =  $12.5\%$  failed to complete.

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner’s or applicable Generator Owner’s system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.

In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner’s or applicable Generator Owner’s easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.



**FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)<sup>9</sup>  
For Alternating Current Voltages (feet)**

( AC ) Nominal System Voltage (KV)	( AC ) Maximum System Voltage (kV) <sup>10</sup>	MVCD (feet)	MVCD (feet)	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet
		Over sea level up to 500 ft	Over 500 ft up to 1000 ft	Over 1000 ft up to 2000 ft	Over 2000 ft up to 3000 ft	Over 3000 ft up to 4000 ft	Over 4000 ft up to 5000 ft	Over 5000 ft up to 6000 ft	Over 6000 ft up to 7000 ft	Over 7000 ft up to 8000 ft	Over 8000 ft up to 9000 ft	Over 9000 ft up to 10000 ft	Over 10000 ft up to 11000 ft
765	800	8.2ft	8.33ft	8.61ft	8.89ft	9.17ft	9.45ft	9.73ft	10.01ft	10.29ft	10.57ft	10.85ft	11.13ft
500	550	5.15ft	5.25ft	5.45ft	5.66ft	5.86ft	6.07ft	6.28ft	6.49ft	6.7ft	6.92ft	7.13ft	7.35ft
345	362	3.19ft	3.26ft	3.39ft	3.53ft	3.67ft	3.82ft	3.97ft	4.12ft	4.27ft	4.43ft	4.58ft	4.74ft
287	302	3.88ft	3.96ft	4.12ft	4.29ft	4.45ft	4.62ft	4.79ft	4.97ft	5.14ft	5.32ft	5.50ft	5.68ft
230	242	3.03ft	3.09ft	3.22ft	3.36ft	3.49ft	3.63ft	3.78ft	3.92ft	4.07ft	4.22ft	4.37ft	4.53ft
161*	169	2.05ft	2.09ft	2.19ft	2.28ft	2.38ft	2.48ft	2.58ft	2.69ft	2.8ft	2.91ft	3.03ft	3.14ft
138*	145	1.74ft	1.78ft	1.86ft	1.94ft	2.03ft	2.12ft	2.21ft	2.3ft	2.4ft	2.49ft	2.59ft	2.7ft
115*	121	1.44ft	1.47ft	1.54ft	1.61ft	1.68ft	1.75ft	1.83ft	1.91ft	1.99ft	2.07ft	2.16ft	2.25ft
88*	100	1.18ft	1.21ft	1.26ft	1.32ft	1.38ft	1.44ft	1.5ft	1.57ft	1.64ft	1.71ft	1.78ft	1.86ft
69*	72	0.84ft	0.86ft	0.90ft	0.94ft	0.99ft	1.03ft	1.08ft	1.13ft	1.18ft	1.23ft	1.28ft	1.34ft

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

<sup>9</sup> The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

<sup>10</sup> Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.



**TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)<sup>7</sup>  
For Alternating Current Voltages (meters)**

( AC ) Nominal System Voltage (KV)	( AC ) Maximum System Voltage (kV) <sup>8</sup>	MVCD meters  Over sea level up to 152.4 m	MVCD meters  Over 152.4 m up to 304.8 m	MVCD meters  Over 304.8 m up to 609.6m	MVCD meters  Over 609.6m up to 914.4m	MVCD meters  Over 914.4m up to 1219.2m	MVCD meters  Over 1219.2m up to 1524m	MVCD meters  Over 1524 m up to 1828.8 m	MVCD meters  Over 1828.8m up to 2133.6m	MVCD meters  Over 2133.6m up to 2438.4m	MVCD meters  Over 2438.4m up to 2743.2m	MVCD meters  Over 2743.2m up to 3048m	MVCD meters  Over 3048m up to 3352.8m
765	800	2.49m	2.54m	2.62m	2.71m	2.80m	2.88m	2.97m	3.05m	3.14m	3.22m	3.31m	3.39m
500	550	1.57m	1.6m	1.66m	1.73m	1.79m	1.85m	1.91m	1.98m	2.04m	2.11m	2.17m	2.24m
345	362	0.97m	0.99m	1.03m	1.08m	1.12m	1.16m	1.21m	1.26m	1.30m	1.35m	1.40m	1.44m
287	302	1.18m	0.88m	1.26m	1.31m	1.36m	1.41m	1.46m	1.51m	1.57m	1.62m	1.68m	1.73m
230	242	0.92m	0.94m	0.98m	1.02m	1.06m	1.11m	1.15m	1.19m	1.24m	1.29m	1.33m	1.38m
161*	169	0.62m	0.64m	0.67m	0.69m	0.73m	0.76m	0.79m	0.82m	0.85m	0.89m	0.92m	0.96m
138*	145	0.53m	0.54m	0.57m	0.59m	0.62m	0.65m	0.67m	0.70m	0.73m	0.76m	0.79m	0.82m
115*	121	0.44m	0.45m	0.47m	0.49m	0.51m	0.53m	0.56m	0.58m	0.61m	0.63m	0.66m	0.69m
88*	100	0.36m	0.37m	0.38m	0.40m	0.42m	0.44m	0.46m	0.48m	0.50m	0.52m	0.54m	0.57m
69*	72	0.26m	0.26m	0.27m	0.29m	0.30m	0.31m	0.33m	0.34m	0.36m	0.37m	0.39m	0.41m

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

**TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)<sup>7</sup>**  
 For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)
	Over sea level up to 500 ft	Over 500 ft up to 1000 ft	Over 1000 ft up to 2000 ft	Over 2000 ft up to 3000 ft	Over 3000 ft up to 4000 ft	Over 4000 ft up to 5000 ft	Over 5000 ft up to 6000 ft	Over 6000 ft up to 7000 ft	Over 7000 ft up to 8000 ft	Over 8000 ft up to 9000 ft	Over 9000 ft up to 10000 ft	Over 10000 ft up to 11000 ft
	(Over sea level up to 152.4 m)	(Over 152.4 m up to 304.8 m)	(Over 304.8 m up to 609.6m)	(Over 609.6m up to 914.4m)	(Over 914.4m up to 1219.2m)	(Over 1219.2m up to 1524m)	(Over 1524 m up to 1828.8 m)	(Over 1828.8m up to 2133.6m)	(Over 2133.6m up to 2438.4m)	(Over 2438.4m up to 2743.2m)	(Over 2743.2m up to 3048m)	(Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

**Notes:**

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet Equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 uses the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-01 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines, as such, are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-

service ac line is approximately 2.0 per unit. This value is a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below is considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit is considered a realistic maximum.

The Gallet Equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet Equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

While EPRI is currently trying to establish empirical data for spark-over distances to live vegetation, there are no spark-over formulas currently derived expressly for vegetation to conductor minimum distances. Therefore the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

**Comparison of spark-over distances computed using Gallet wet equations vs.  
IEEE 516-2003 MAID distances**

( AC ) Nom System Voltage (kV)	( AC ) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 feet	Table 7 (Table D.5 for feet) IEEE 516-2003 MAID (ft) @ Alt. 3000 feet
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

Effective Dates

~~This~~ There are two effective dates associated with this standard.

The first effective date allows Generator Owners time to develop documented maintenance strategies or procedures or processes or specifications as outlined in Requirement R3.

In those jurisdictions where regulatory approval is required, Requirement R3 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. Where In those jurisdictions where no regulatory approval is required, the standard Requirement R3 becomes effective on the first calendar day of the first calendar quarter one year after following Board of Trustees Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Requirement	Jurisdiction							
	Alberta	British Columbia	Manitoba	New Brunswick	Newfoundland	Nova Scotia	Ontario	Quebec
<del>R1—R7</del> (All Req.)	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD

The second effective date allows entities time to comply with Requirements R1, R2, R4, R5, R6, and R7.

In those jurisdictions where regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 become effective on the first day of the first calendar quarter two years following Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an

IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.

2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.
3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.
4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.
5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

Version History

<u>Version</u>	<u>Date</u>	<u>Action</u>	<u>Change Tracking</u>
<u>3</u>	<u>September 29, 2011</u>	<u>Using the latest draft of FAC-003-2 from the Project 2007-07 SDT, modified proposed definitions and Applicability to include Generator Owners of a certain length.</u>	<u>Revision under Project 2010-07</u>

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

### **Right-of-Way (ROW)**

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria.

The current glossary definition of this NERC term is modified to address the issues set forth in Paragraph 734 of FERC Order 693.

The Project 2010-07 team further modified that proposed definition to include applicable Generator Owners.

### **Vegetation Inspection**

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the applicable Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.

The Project 2010-07 team further modified that proposed definition to include applicable Generator Owners.

Current definition of Vegetation Inspection:  
The systematic examination of a transmission corridor to document vegetation conditions.

### **Minimum Vegetation Clearance Distance (MVCD)**

The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.



When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.

FAC-003-2 was developed under Project 2007-07. The standard was balloted and adopted by the NERC Board of Trustees, but the Project 2010-07 drafting team does not want to assume that FAC-003-2 will be approved by FERC and other governmental authorities. Thus, the Project 2010-07 drafting team has developed two sets of proposed changes: one to this version, FAC-003-2, the version developed by the Project 2007-07 team and adopted by NERC’s Board of Trustees, and one to FAC-003-1, the current FERC-approved version of the standard.

## A. Introduction

1. **Title:** Transmission Vegetation Management
2. **Number:** FAC-003-~~23~~
3. **Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

### 4. Applicability

#### 4.1. Functional Entities:

~~4.1.1.4.1.1.1. 4.1.1-Applicable~~  
Transmission Owners

4.1.1.1 Transmission Owners that own  
Transmission Facilities defined in 4.2.

4.1.2 Applicable Generator Owners

4.1.2.1 Generator Owners that own  
generation Facilities defined in 4.3

- 4.2. **Transmission Facilities:** Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal<sup>1</sup>, state, provincial, public, private, or tribal entities:

**Rationale:** The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing processes manage the threat. As such, the formal steps in this standard are not well suited for this environment. ~~3) NERC has a project in place to address at a later date the applicability of this standard to Generation Owners. 4) 3)~~ Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

<sup>1</sup> EPAAct 2005 section 1211c: “Access approvals by Federal agencies.”

**4.2.1** — Each overhead transmission line operated at 200kV or higher.

**4.2.2** — Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.

**4.2.3** — Each overhead transmission line operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

**4.2.4** — Each overhead transmission line identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

**4.3. Generation Facilities: Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal<sup>2</sup>, state, provincial, public, private, or tribal entities:**

**4.3.1** Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner’s Facility or (2) do not have a clear line of sight<sup>3</sup> from the generating station switchyard fence to the point of interconnection with a Transmission Owner’s Facility and are:

**4.3.1.1** Operated at 200kV or higher; or

**4.3.1.2** Operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator; or

**4.3.1.3** Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

Within the text of NERC Reliability Standard FAC-003-3, “transmission line(s) and “applicable line(s) can also refer to the generation Facilities as referenced in 4.3 and its subsections.

Enforcement:

The Requirements within a Reliability Standard govern and will be enforced. The Requirements within a Reliability Standard define what an entity must do to be compliant and binds an entity to certain obligations of performance under Section 215 of the Federal Power Act. Compliance will in all cases be measured by determining whether a party met or failed to meet the Reliability Standard Requirement given the specific facts and circumstances of its use, ownership or operation of the bulk power system.

<sup>2</sup> EPAAct 2005 section 1211c: “Access approvals by Federal agencies.”

<sup>3</sup> “Clear line of sight” means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.

Measures provide guidance on assessing non-compliance with the Requirements. Measures are the evidence that could be presented to demonstrate compliance with a Reliability Standard Requirement and are not intended to contain the quantitative metrics for determining satisfactory performance nor to limit how an entity may demonstrate compliance if valid alternatives to demonstrating compliance are available in a specific case. A Reliability Standard may be enforced in the absence of specified Measures.

Entities must comply with the “Compliance” section in its entirety, including the Administrative Procedure that sets forth, among other things, reporting requirements.

The “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” are provided for informational purposes. They are designed to convey guidance from NERC’s various activities. The “Guideline and Technical Basis” section and text boxes with “Examples” and “Rationale” are not intended to establish new Requirements under NERC’s Reliability Standards or to modify the Requirements in any existing NERC Reliability Standard. Implementation of the “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” is not a substitute for compliance with Requirements in NERC’s Reliability Standards.”

## **5. Background:**

This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

- a) Performance-based — defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome?*
- b) Risk-based — preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?*
- c) Competency-based — defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?*

The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall

defense-in-depth strategy and comport with the quality objectives of a reliability standard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

For this standard, the requirements have been developed as follows:

Performance-based: Requirements 1 and 2

Competency-based: Requirement 3

Risk-based: Requirements 4, 5, 6 and 7

R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term “public lands” includes municipal lands, village lands, city lands, and a host of other governmental entities.

This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

## B. Requirements and Measures

**R1.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below<sup>4</sup> [*Violation Risk Factor: High*] [*Time Horizon: Real-time*]:

1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage<sup>56</sup> ~~7~~ ~~→~~
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage<sup>78</sup> ~~7~~ ~~→~~
3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained ~~Outage~~<sup>4</sup> ~~Outage~~<sup>4</sup>.
4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-

<sup>4</sup> This requirement does not apply to circumstances that are beyond the control of the Owner or applicable Generator Owner subject to this reliability standard, including but not limited to: earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.

~~wner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.~~

<sup>6</sup> If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

<sup>8</sup> Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

### Rationale for R1 and R2:

Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable Transmission Owner's or applicable Generator Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.
2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

related Sustained ~~Outage~~<sup>4</sup>Outage<sup>4</sup>.

- M1.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)
- R2.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below<sup>2</sup> [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time*]:
1. An encroachment into the MVCD, observed in Real-time, absent a Sustained ~~Outage~~<sup>3</sup>Outage<sup>3</sup>.
  2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained ~~Outage~~<sup>4</sup>Outage<sup>4</sup>.
  3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained ~~Outage~~<sup>4</sup>Outage<sup>4</sup>.
  4. An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage<sup>4</sup>
- M2.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)



**R3.** Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following:

- 3.1** Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;
- 3.2** Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

*[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]:*

**Rationale**

The documentation provides a basis for evaluating the competency of the applicable Transmission Owner's or applicable Generator Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions. See Figure 1 for an illustration of possible conductor locations.

**M3.** The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

**R4.** Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment *[Violation Risk Factor: Medium] [Time Horizon: Real-time]*.

**Rationale**

This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

**M4.** Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)



**R5.** When a applicable Transmission Owner and applicable Generator Owner is constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

#### Rationale

Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner to put interim measures in place, rather than do nothing. The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

**M5.** Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

#### Rationale

Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

**R6.** Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW<sup>9</sup> [*Violation Risk Factor:*

<sup>9</sup> When the applicable Transmission Owner or applicable Generator Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a time extension

*Medium*] [*Time Horizon: Operations Planning*].

**M6.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

**R7.** Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan

**Rationale**

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

(measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

- Change in expected growth rate/ environmental factors
- Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner<sup>10</sup>
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Emerging technologies

that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.

<sup>10</sup> Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.

- M7. Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

## C. Compliance

### 1. Compliance Monitoring Process

#### 1.1 Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

For NERC, a third-party monitor without vested interest in the outcome for NERC shall serve as the Compliance Enforcement Authority.

#### 1.2 Regional Entity Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, Measures M1, M2, M3, M5, M6 and M7 for three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification  
Spot Checking  
Compliance Violation Investigation  
Self-Reporting  
Complaint  
Periodic Data Submittal

#### 1.4 Additional Compliance Information

***Periodic Data Submittal:*** The applicable Transmission Owner and applicable Generator Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;

- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Real-time	High	N/A	N/A	The <del>Transmission Owner</del> responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.	The <del>Transmission Owner</del> responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following: <ul style="list-style-type: none"> <li>• A fall-in from inside the active transmission line ROW</li> <li>• Blowing together of applicable lines and vegetation located inside the active transmission line ROW</li> <li>• A grow-in</li> </ul>
R2	Real-time	Medium	N/A	N/A	The <del>Transmission Owner</del> responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time	The <del>Transmission Owner</del> responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of

					absent a Sustained Outage.	the following: <ul style="list-style-type: none"> <li>• A fall-in from inside the active transmission line ROW</li> <li>• Blowing together of applicable lines and vegetation located inside the active transmission line ROW</li> <li>• A grow-in</li> </ul>
R3	Long-Term Planning	Lower	N/A	The <del>Transmission Owner</del> responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the <del>Transmission Owner's</del> responsible entity's applicable lines. (Requirement R3, Part 3.2)	The <del>Transmission Owner</del> responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the <del>Transmission Owner's</del> responsible entity's applicable lines. Requirement R3, Part 3.1)	The <del>Transmission Owner</del> responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the <del>Transmission Owner's</del> responsible entity's applicable lines.
R4	Real-time	Medium	N/A	N/A	The <del>Transmission Owner</del> responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The <del>Transmission Owner</del> responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.

R5	Operations Planning	Medium	N/A	N/A	N/A	The <del>Transmission Owner</del> responsible entity did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6	Operations Planning	Medium	The <del>Transmission Owner</del> responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The <del>Transmission Owner</del> responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The <del>Transmission Owner</del> responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The <del>Transmission Owner</del> responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7	Operations Planning	Medium	The <del>Transmission Owner</del> responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The <del>Transmission Owner</del> responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The <del>Transmission Owner</del> responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The <del>Transmission Owner</del> responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Differences

None.

E. Interpretations

None.

F. Associated Documents

Guideline and Technical Basis (attached).





## Guideline and Technical Basis

### **Enforcement:**

~~The Requirements within a Reliability Standard govern and will be enforced. The Requirements within a Reliability Standard define what an entity must do to be compliant and binds an entity to certain obligations of performance under Section 215 of the Federal Power Act. Compliance will in all cases be measured by determining whether a party met or failed to meet the Reliability Standard Requirement given the specific facts and circumstances of its use, ownership or operation of the bulk power system.~~

~~Measures provide guidance on assessing non-compliance with the Requirements. Measures are the evidence that could be presented to demonstrate compliance with a Reliability Standard Requirement and are not intended to contain the quantitative metrics for determining satisfactory performance nor to limit how an entity may demonstrate compliance if valid alternatives to demonstrating compliance are available in a specific case. A Reliability Standard may be enforced in the absence of specified Measures.~~

~~Entities must comply with the “Compliance” section in its entirety, including the Administrative Procedure that sets forth, among other things, reporting requirements.~~

~~The “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” are provided for informational purposes. They are designed to convey guidance from NERC’s various activities. The “Guideline and Technical Basis” section and text boxes with “Examples” and “Rationale” are not intended to establish new Requirements under NERC’s Reliability Standards or to modify the Requirements in any existing NERC Reliability Standard. Implementation of the “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” is not a substitute for compliance with Requirements in NERC’s Reliability Standards.”~~

### **Effective dates:**

The first two sentences of the Effective Dates section is standard language used in most NERC standards to cover the general effective date and is sufficient to cover the vast majority of situations. Five special cases are needed to cover effective dates for individual lines which undergo transitions after the general effective date. These special cases cover the effective dates for those lines which are initially becoming subject to the standard, those lines which are changing their applicability within the standard, and those lines which are changing in a manner that removes their applicability to the standard.

Case 1 is needed because the Planning Coordinators may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2011 may identify a line to have that designation beginning in PY 2021, ten years after the planning study is performed. It is not

intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. The table below has some explanatory examples of the application.

<u>Date that Planning Study is completed</u>	<u>PY the line will become an IROL element</u>	<u>Date 1</u>	<u>Date 2</u>	<u>Effective Date The latter of Date 1 or Date 2</u>
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Case 2 is needed because a line operating below 200kV designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Case 3 is needed because a line operating at 200 kV or above that once was designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network. Such changes result in the need to apply R1 to that line until that date is reached and then to apply R2 to that line thereafter.

Case 4 is needed because an existing line that is to be operated at 200 kV or above can be acquired by an applicable Transmission Owner or applicable Generator Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network which will thereafter make the line subject to the standard.

Case 5 is needed because an existing line that is operated below 200 kV can be acquired by an applicable Transmission Owner or applicable Generator Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission owner Owner or applicable Generator Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network. In this special case the line upon acquisition was designated as an element of an Interconnection Reliability Operating Limit (IROL) or an element of a Major WECC Transfer Path.

**Defined Terms:**

**Explanation for revising the definition of ROW:**

The current NERC glossary definition of Right of Way has been modified to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This modified definition represents a slight but significant departure from the strict legal definition of “right of way” in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the revised definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

The Project 2010-07 team further modified that proposed definition to include applicable Generator Owners.

**Explanation for revising the definition of Vegetation Inspections:**

The current glossary definition of this NERC term is being modified to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

The Project 2010-07 team further modified that proposed definition to include applicable Generator Owners.

**Explanation of the definition of the MVCD:**

The MVCD is a calculated minimum distance that is derived from the Gallet Equations. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 below provides MVCD values for various voltages and altitudes. Details of the equations and an example calculation are provided in Appendix 1 of the Technical Reference Document.

**Guidelines:**

**Requirements R1 and R2:**

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each applicable Transmission Owner or applicable Generator Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element of an IROL or Major WECC Transfer Path. R2 is applicable to all other lines that are not elements of IROLs, and not elements of Major WECC Transfer Paths.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations as described more fully in the Technical Reference document.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by ~~an applicable~~ Transmission ~~Operator~~ Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of ~~an applicable~~ Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with ~~an~~ applicable Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are

that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will prevent transmission outages.

If the applicable Transmission Owner or applicable Generator Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the ~~TO~~applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

**Requirement R3:**

R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, ~~an applicable~~ Transmission Owner or applicable Generator Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

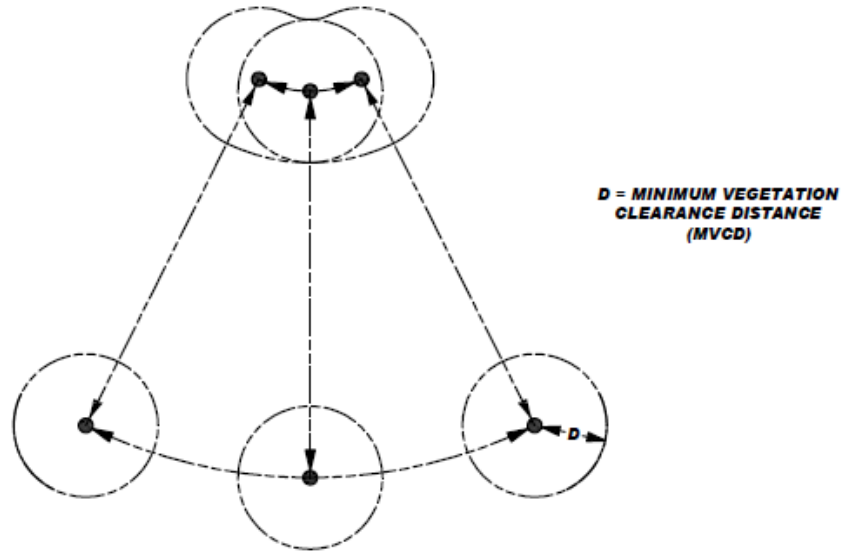
An example of one approach commonly used by industry is ANSI Standard A300, part 7.

However, regardless of the approach a utility uses to manage vegetation, any approach ~~an~~ applicable Transmission Owner or applicable Generator Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor’s position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of

line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below. In the Technical Reference document more figures and explanations of conductor dynamics are provided.



**Figure 1**

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

**Requirement R4:**

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner's Owner or applicable Generator Owner employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved.



Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owner or applicable Generator Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

#### **Requirement R5:**

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the applicable Transmission Owner or applicable Generator Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.

- The applicable Transmission Owner or applicable Generator Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

**Requirement R6:**

R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner's ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission Owner or applicable Generator Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when ~~a~~-an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be  $100/2000 = 0.05$  or 5%. The "Low VSL" for R6 would apply in this example.

**Requirement R7:**

R7 is a risk-based requirement. The applicable Transmission Owner or applicable Generator Owner is required to complete its an annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a "span-by-span", or even a "line-by-line" detailed description of all work to be performed. It is only intended to require that the applicable Transmission Owner or applicable Generator Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

For example, when ~~a~~-an applicable Transmission Owner or applicable Generator Owner identifies 1,000 miles of applicable transmission lines to be completed in the applicable Transmission Owner's or applicable Generator Owner's annual plan, the applicable Transmission Owner or applicable Generator Owner will be responsible completing those identified miles. If a applicable Transmission Owner or applicable Generator Owner makes a modification to the annual plan that does not put the transmission system at risk of an

encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be:  $1000 - 100$  (deferred miles) = 900 modified annual plan, or  $900 / 900 = 100\%$  completed annual miles. If an applicable Transmission Owner or applicable Generator Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be:  $1000 - 875 = 125$  miles failed to complete then, 125 miles (not completed) / 1000 total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner's or applicable Generator Owner's system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.

In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner's or applicable Generator Owner's easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)<sup>11</sup>  
 For **Alternating Current** Voltages (feet)

( AC ) Nominal System Voltage (KV)	( AC ) Maximum System Voltage (kV) <sup>12</sup>	MVCD (feet)	MVCD (feet)	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet	MVCD feet
		Over sea level up to 500 ft	Over 500 ft up to 1000 ft	Over 1000 ft up to 2000 ft	Over 2000 ft up to 3000 ft	Over 3000 ft up to 4000 ft	Over 4000 ft up to 5000 ft	Over 5000 ft up to 6000 ft	Over 6000 ft up to 7000 ft	Over 7000 ft up to 8000 ft	Over 8000 ft up to 9000 ft	Over 9000 ft up to 10000 ft	Over 10000 ft up to 11000 ft
765	800	8.2ft	8.33ft	8.61ft	8.89ft	9.17ft	9.45ft	9.73ft	10.01ft	10.29ft	10.57ft	10.85ft	11.13ft
500	550	5.15ft	5.25ft	5.45ft	5.66ft	5.86ft	6.07ft	6.28ft	6.49ft	6.7ft	6.92ft	7.13ft	7.35ft
345	362	3.19ft	3.26ft	3.39ft	3.53ft	3.67ft	3.82ft	3.97ft	4.12ft	4.27ft	4.43ft	4.58ft	4.74ft
287	302	3.88ft	3.96ft	4.12ft	4.29ft	4.45ft	4.62ft	4.79ft	4.97ft	5.14ft	5.32ft	5.50ft	5.68ft
230	242	3.03ft	3.09ft	3.22ft	3.36ft	3.49ft	3.63ft	3.78ft	3.92ft	4.07ft	4.22ft	4.37ft	4.53ft
161*	169	2.05ft	2.09ft	2.19ft	2.28ft	2.38ft	2.48ft	2.58ft	2.69ft	2.8ft	2.91ft	3.03ft	3.14ft
138*	145	1.74ft	1.78ft	1.86ft	1.94ft	2.03ft	2.12ft	2.21ft	2.3ft	2.4ft	2.49ft	2.59ft	2.7ft
115*	121	1.44ft	1.47ft	1.54ft	1.61ft	1.68ft	1.75ft	1.83ft	1.91ft	1.99ft	2.07ft	2.16ft	2.25ft
88*	100	1.18ft	1.21ft	1.26ft	1.32ft	1.38ft	1.44ft	1.5ft	1.57ft	1.64ft	1.71ft	1.78ft	1.86ft
69*	72	0.84ft	0.86ft	0.90ft	0.94ft	0.99ft	1.03ft	1.08ft	1.13ft	1.18ft	1.23ft	1.28ft	1.34ft

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

<sup>11</sup> The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

<sup>12</sup> Where applicable lines are operated at nominal voltages other than those listed, ~~the applicable~~ Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

**TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)<sup>7</sup>  
For Alternating Current Voltages (meters)**

( AC ) Nominal System Voltage (KV)	( AC ) Maximum System Voltage (kV) <sup>8</sup>	MVCD meters  Over sea level up to 152.4 m	MVCD meters  Over 152.4 m up to 304.8 m	MVCD meters  Over 304.8 m up to 609.6m	MVCD meters  Over 609.6m up to 914.4m	MVCD meters  Over 914.4m up to 1219.2m	MVCD meters  Over 1219.2m up to 1524m	MVCD meters  Over 1524 m up to 1828.8 m	MVCD meters  Over 1828.8m up to 2133.6m	MVCD meters  Over 2133.6m up to 2438.4m	MVCD meters  Over 2438.4m up to 2743.2m	MVCD meters  Over 2743.2m up to 3048m	MVCD meters  Over 3048m up to 3352.8m
765	800	2.49m	2.54m	2.62m	2.71m	2.80m	2.88m	2.97m	3.05m	3.14m	3.22m	3.31m	3.39m
500	550	1.57m	1.6m	1.66m	1.73m	1.79m	1.85m	1.91m	1.98m	2.04m	2.11m	2.17m	2.24m
345	362	0.97m	0.99m	1.03m	1.08m	1.12m	1.16m	1.21m	1.26m	1.30m	1.35m	1.40m	1.44m
287	302	1.18m	0.88m	1.26m	1.31m	1.36m	1.41m	1.46m	1.51m	1.57m	1.62m	1.68m	1.73m
230	242	0.92m	0.94m	0.98m	1.02m	1.06m	1.11m	1.15m	1.19m	1.24m	1.29m	1.33m	1.38m
161*	169	0.62m	0.64m	0.67m	0.69m	0.73m	0.76m	0.79m	0.82m	0.85m	0.89m	0.92m	0.96m
138*	145	0.53m	0.54m	0.57m	0.59m	0.62m	0.65m	0.67m	0.70m	0.73m	0.76m	0.79m	0.82m
115*	121	0.44m	0.45m	0.47m	0.49m	0.51m	0.53m	0.56m	0.58m	0.61m	0.63m	0.66m	0.69m
88*	100	0.36m	0.37m	0.38m	0.40m	0.42m	0.44m	0.46m	0.48m	0.50m	0.52m	0.54m	0.57m
69*	72	0.26m	0.26m	0.27m	0.29m	0.30m	0.31m	0.33m	0.34m	0.36m	0.37m	0.39m	0.41m

\* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)<sup>7</sup>  
 For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)
	Over sea level up to 500 ft	Over 500 ft up to 1000 ft	Over 1000 ft up to 2000 ft	Over 2000 ft up to 3000 ft	Over 3000 ft up to 4000 ft	Over 4000 ft up to 5000 ft	Over 5000 ft up to 6000 ft	Over 6000 ft up to 7000 ft	Over 7000 ft up to 8000 ft	Over 8000 ft up to 9000 ft	Over 9000 ft up to 10000 ft	Over 10000 ft up to 11000 ft
	(Over sea level up to 152.4 m)	(Over 152.4 m up to 304.8 m)	(Over 304.8 m up to 609.6m)	(Over 609.6m up to 914.4m)	(Over 914.4m up to 1219.2m)	(Over 1219.2m up to 1524m)	(Over 1524 m up to 1828.8 m)	(Over 1828.8m up to 2133.6m)	(Over 2133.6m up to 2438.4m)	(Over 2438.4m up to 2743.2m)	(Over 2743.2m up to 3048m)	(Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

### Notes:

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet Equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 uses the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-01 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines, as such, are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-



service ac line is approximately 2.0 per unit. This value is a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below is considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit is considered a realistic maximum.

The Gallet Equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet Equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

While EPRI is currently trying to establish empirical data for spark-over distances to live vegetation, there are no spark-over formulas currently derived expressly for vegetation to conductor minimum distances. Therefore the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.



**Comparison of spark-over distances computed using Gallet wet equations vs. IEEE 516-2003 MAID distances**

( AC ) Nom System Voltage (kV)	( AC ) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 feet	Table 7 (Table D.5 for feet) IEEE 516-2003 MAID (ft) @ Alt. 3000 feet
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

**Rationale:**

~~During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.~~

**Rationale for Applicability (section 4.2.4):**

~~The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) NERC has a project in place to address at a later date the applicability of this standard to Generation Owners. 4) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.~~

**Rationale for R1 and R2:**

~~Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.~~

**Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a Transmission Owner's vegetation maintenance program:**

~~1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.~~

~~2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.~~

~~3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.~~

~~4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.~~

**Rationale for R3:**

~~The documentation provides a basis for evaluating the competency of the Transmission Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the Transmission Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions. See Figure 1 for an illustration of possible conductor locations.~~

**Rationale for R4:**

~~This is to ensure expeditious communication between the Transmission Owner and the control center when a critical situation is confirmed.~~

**Rationale for R5:**

~~Legal actions and other events may occur which result in constraints that prevent the Transmission Owner from performing planned vegetation maintenance work. In cases where the transmission line is put at potential risk due to constraints, the intent is for the Transmission Owner to put interim measures in place, rather than do nothing. The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.~~

**Rationale for R6:**

~~Inspections are used by Transmission Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.~~

**Rationale for R7:**

~~This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors,~~

~~provided that those modifications do not put the transmission system at risk of a vegetation encroachment.~~

**Version History**

<b>Version</b>	<b>Date</b>	<b>Action</b>	<b>Change Tracking</b>
<del>1</del>	<del>TBA</del>	<del>1. Added "Standard Development Roadmap."</del> <del>2. Changed "60" to "Sixty" in section A, 5.2.</del> <del>3. Added "Proposed Effective Date: April 7, 2006" to footer.</del> <del>4. Added "Draft 3: November 17, 2005" to footer.</del>	<del>01/20/06</del>
<del>1</del>	<del>April 4, 2007</del>	<del>Regulatory Approval—Effective Date</del>	<del>New</del>
<del>2</del>	<del>November 3, 2011</del>	<del>Adopted by the NERC Board of Trustees</del>	

# Implementation Plan for FAC-003-3 — Transmission Vegetation Management

## Prerequisite Approvals

There are a number of scenarios that could occur regarding the approval of FAC-003-2 that would affect the implementation of FAC-003-3.

If FAC-003-2 is filed with applicable regulatory authorities and approved before FAC-003-3 is filed with applicable regulatory authorities, then when and if FAC-003-3 is approved by applicable regulatory authorities, the implementation plan and effective dates for Transmission Owners in FAC-003-2 will be transferred into this implementation plan. The “clock” for calculating effective dates for Transmission Owners will still have started at the time specified in FAC-003-2 (based on the approval date of that standard). Generator Owners will be required to comply with the implementation plan as outlined below.

If applicable regulatory authorities elect to approve only FAC-003-3 and not FAC-003-2, the original implementation plan for Transmission Owners as outlined in FAC-003-2 will be transferred into this implementation plan. Generator Owners will be required to comply with the implementation plan as outlined below. The “clocks” for calculating the effective dates for both Transmission Owners and Generator Owners will begin at the same time.

If applicable regulatory authorities approve FAC-003-2 and FAC-003-3 at the same time, the implementation plan and effective dates for Transmission Owners in FAC-003-2 will be transferred into this implementation plan and FAC-003-2 will be immediately retired. Generator Owners will be required to comply with the implementation plan as outlined below. The “clocks” for calculating the effective dates for both Transmission Owners and Generator Owners will begin at the same time.

## Revision to Sections of Approved Standards and Definitions

There are no proposed revisions to requirements in other already approved standards. All requirements and the two revised definitions in the proposed standard FAC-003-2 will be retired at midnight the day before FAC-003-3 becomes effective.

There are two revised definitions in the proposed standard:

### Right-of-Way (ROW)

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either

construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria.

### **Vegetation Inspection**

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

There is one new definition in the proposed standard:

### **Minimum Vegetation Clearance Distance (MVCD)**

The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

The current glossary definitions of Right-of-Way and Vegetation Inspection, or the glossary definitions of Right-of-Way and Vegetation Inspection in FAC-003-2, if that standard has been approved, will be retired at midnight the day before FAC-003-3 (and with it, the above definitions of Right-of-Way and Vegetation Inspection) becomes effective. The above definition of Minimum Vegetation Clearance Distance will be added to the NERC Glossary of Terms upon approval of FAC-003-3, or the above definition of Minimum Vegetation Clearance Distance will replace (and thus force the retirement, at midnight the day before FAC-003-3 is approved) of the same definition in FAC-003-2, if FAC-003-2 has been approved.

### **Compliance with Standard**

As outlined above under "Prerequisite Approvals," the inclusion of Transmission Owners in this implementation plan will depend on the order in which regulatory authorities approve FAC-003-2 and FAC-003-3. Therefore, this implementation plan only identifies a compliance timeframe for Generator Owners to which this standard will apply.

To reach compliance with the standard, a Generator Owner will have to perform a full review of as-built drawings and determine which generation interconnection Facilities require a Transmission Vegetation Management Plan (TVMP) and inspection as specified by NERC Reliability Standard FAC-003-3. In general, Generator Owners do not have staff that are qualified and experienced to create a TVMP, perform Right-of-Way inspections, and perform any required tree trimming). Once a complete inventory is created, the Generator Owner will begin the process of gathering information for the TVMP. In instances where the generation interconnection Facilities are owned by a partnership, a majority or operating partner will need to obtain partnership approval to proceed with procurement of

a TVMP expert, and later a tree trimming crew. Typically, a request for proposal to hire a TVMP consultant is initiated which could take several weeks in order to obtain sufficient bids (and also satisfy Sarbanes Oxley requirements). Once all bids have been received, a contract with a TVMP consultant is signed. At this point, the TVMP consultant and Generator Owner staff will develop the TVMP, which needs to take into account local growth conditions, types of vegetation and other aspects required by FAC-003. Once the TVMP is developed, Generator Owner staff and the TVMP consultant will need to perform a Right-of-Way inspection (as required in FAC-003-3 Requirement 1), usually done using GPS, LIDAR and other tools by experienced and qualified staff.

Once a Right-of-Way inspection is completed and clearances are required, the Generator Owner will need to issue a request for proposal to hire a tree trimming crew that is qualified and experienced to perform required clearance trimming. Once all bids have been received, a contract with a tree trimming crew is signed. When the tree trimming crew is acquired, the crew will need to familiarize themselves with the entity's TVMP and required clearances. The Generator Owner will typically need to schedule any required outages in order for the tree trimming crew to perform the needed clearance trimming. This action would also include the implementation of the work plan as required in FAC-003-3 Requirement 2. During scheduled outages, if required, the tree trimming crew will perform any required clearances and document the activities.

Another typical action is the Generator Owner establishing a system for maintaining TVMP-related activities, including maintenance of inspection and clearance documentation. On an ongoing basis, in addition to performing inspections and clearances as required by the entity's TVMP, the Generator Owner will need to ensure that the training and qualification requirements for the standard are met. The entity will also need to maintain documentation of all FAC-003-3 activities for compliance period of one year to meet compliance with the standard.

Again, due to a typical lack of experience and qualifications required by FAC-003-3, compliance with this standard by a Generator Owner may take as long as two years – in part because many entities will have generator interconnection Facilities in various parts of the country which may require several instances of TVMP and numerous Right-of-Way inspections.

### **Effective Date**

There are two effective dates associated with this implementation plan:

The first effective date allows Generator Owners time to develop documented maintenance strategies or procedures or processes or specifications as outlined in Requirement R3.

In those jurisdictions where regulatory approval is required, Requirement R3 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities

where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

The second effective date allows entities time to comply with Requirements R1, R2, R4, R5, R6, and R7.

In those jurisdictions where regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 become effective on the first day of the first calendar quarter two years following Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.
2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.
3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.
4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.



5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

# Implementation Plan for FAC-003-3 — Transmission Vegetation Management

## Prerequisite Approvals

There are a number of scenarios that could occur regarding the approval of FAC-003-2 that would affect the implementation of FAC-003-3.

If FAC-003-2 is filed with applicable regulatory authorities and approved before FAC-003-3 is filed with applicable regulatory authorities, then when and if FAC-003-3 is approved by applicable regulatory authorities, the implementation plan and effective dates for Transmission Owners in FAC-003-2 will be transferred into this implementation plan. The “clock” for calculating effective dates for Transmission Owners will still have started at the time specified in FAC-003-2 (based on the approval date of that standard). Generator Owners will be required to comply with the implementation plan as outlined below.

If applicable regulatory authorities elect to approve only FAC-003-3 and not FAC-003-2, the original implementation plan for Transmission Owners as outlined in FAC-003-2 will be transferred into this implementation plan. Generator Owners will be required to comply with the implementation plan as outlined below. The “clocks” for calculating the effective dates for both Transmission Owners and Generator Owners will begin at the same time.

If applicable regulatory authorities approve FAC-003-2 and FAC-003-3 at the same time, the implementation plan and effective dates for Transmission Owners in FAC-003-2 will be transferred into this implementation plan and FAC-003-2 will be immediately retired. Generator Owners will be required to comply with the implementation plan as outlined below. The “clocks” for calculating the effective dates for both Transmission Owners and Generator Owners will begin at the same time.

## Revision to Sections of Approved Standards and Definitions

There are no proposed revisions to requirements in other already approved standards. All requirements and the two revised definitions in the proposed standard FAC-003-2 will be retired at midnight the day before FAC-003-3 becomes effective.

There are two revised definitions in the proposed standard:

### Right-of-Way (ROW)

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either

construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria.

### **Vegetation Inspection**

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

There is one new definition in the proposed standard:

#### **Minimum Vegetation Clearance Distance (MVCD)**

The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

The current glossary definitions of Right-of-Way and Vegetation Inspection, or the glossary definitions of Right-of-Way and Vegetation Inspection in FAC-003-2, if that standard has been approved, will be retired at midnight the day before FAC-003-3 (and with it, the above definitions of Right-of-Way and Vegetation Inspection) becomes effective. The above definition of Minimum Vegetation Clearance Distance will be added to the NERC ~~glossary~~ [Glossary of Terms](#) upon approval of FAC-003-3, or the above definition of Minimum Vegetation Clearance Distance will replace (and thus force the retirement, at midnight the day before FAC-003-3 is approved) of the same definition in FAC-003-2, if FAC-003-2 has been approved.

#### **Compliance with Standard**

As outlined above under "Prerequisite Approvals," the inclusion of Transmission Owners in this implementation plan will depend on the order in which regulatory authorities approve FAC-003-2 and FAC-003-3. Therefore, this implementation plan only identifies a compliance timeframe for Generator Owners to which this standard will apply.

To reach compliance with the standard, a Generator Owner will have to perform a full review of as-built drawings and determine which generation interconnection Facilities require a Transmission Vegetation Management Plan (TVMP) and inspection as specified by NERC Reliability Standard FAC-003-3. In general, Generator Owners do not have staff that are qualified and experienced to create a TVMP, perform Right-of-Way inspections, and perform any required tree trimming (~~as is required by FAC-003-3 Requirement 1.3~~). Once a complete inventory is created, the Generator Owner will begin the process of gathering information for the TVMP. In instances where the generation interconnection Facilities are owned by a partnership, a majority or operating partner will need to obtain partnership

approval to proceed with procurement of a TVMP expert, and later a tree trimming crew. Typically, a request for proposal to hire a TVMP consultant is initiated which could take several weeks in order to obtain sufficient bids (and also satisfy Sarbanes Oxley requirements). Once all bids have been received, a contract with a TVMP consultant is signed. At this point, the TVMP consultant and Generator Owner staff will develop the TVMP, which needs to take into account local growth conditions, types of vegetation and other aspects required by FAC-003. Once the TVMP is developed, Generator Owner staff and the TVMP consultant will need to perform a Right-of-Way inspection (as required in FAC-003-3 Requirement 1), usually done using GPS, LIDAR and other tools by experienced and qualified staff.

Once a Right-of-Way inspection is completed and clearances are required, the Generator Owner will need to issue a request for proposal to hire a tree trimming crew that is qualified and experienced to perform required clearance trimming. Once all bids have been received, a contract with a tree trimming crew is signed. When the tree trimming crew is acquired, the crew will need to familiarize themselves with the entity's TVMP and required clearances. The Generator Owner will typically need to schedule any required outages in order for the tree trimming crew to perform the needed clearance trimming. This action would also include the implementation of the work plan as required in FAC-003-3 Requirement 2. During scheduled outages, if required, the tree trimming crew will perform any required clearances and document the activities.

Another typical action is the Generator Owner establishing a system for maintaining TVMP-related activities, including maintenance of inspection and clearance documentation ~~(as required in FAC-003-3 Requirement 1.2)~~. On an ongoing basis, in addition to performing inspections and clearances as required by the entity's TVMP, the Generator Owner will need to ensure that the training and qualification requirements for the standard are met. The entity will also need to maintain documentation of all FAC-003-3 activities for compliance period of one year to meet compliance with the standard.

Again, due to a typical lack of experience and qualifications required by FAC-003-3, compliance with this standard by a Generator Owner may take as long as two years – in part because many entities will have generator interconnection Facilities in various parts of the country which may require several instances of TVMP and numerous Right-of-Way inspections.

### **Effective Date**

There are two effective dates associated with this implementation plan:

The first effective date allows Generator Owners time to develop documented maintenance strategies or procedures or processes or specifications as outlined in Requirement R3.

In those jurisdictions where regulatory approval is required, Requirement R3 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one

year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

The second effective date allows entities time to comply with Requirements R1, R2, R4, R5, R6, and R7.

In those jurisdictions where regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 become effective on the first day of the first calendar quarter two years following Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.
2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.
3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.
4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.

5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

# Consideration of Comments

## Generator Requirements at the Transmission Interface Project 2010-07 (FAC-003-3 and FAC-003-x)

The Generator Requirements at the Transmission Interface Drafting Team thanks all commenters who submitted comments on the second formal posting of FAC-003-3 and FAC-003-X, as part of Project 2010-07—Generator Requirements at the Transmission Interface. These standards were posted for a 30-day public comment period from March 9, 2012 through April 9, 2012. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 22 sets of comments, including comments from approximately 83 different people from approximately 76 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

The SDT considered all comments submitted and has proposed the following minor changes to FAC-003-X and FAC-003-3:

- **FAC-003-X:**
  - The Applicability section was reformatted to make it clear that the standard applies on a Facility by Facility basis (as in FAC-003-3), not simply to all generator interconnection Facilities owned by a Generator Owner with at least one qualifying generator interconnection Facility.
  - In the Purpose section, Right-of-Way was capitalized because it is an approved NERC glossary term and “North American Electric Reliability Council” was changed to “North American Electric Reliability Corporation.”
  - Regional Entity was added back to the Applicability section of the standard. Requirement R4 is assigned to the Regional Entity, and the Project 2010-07 does not have the authority, based on the scope outlined in its SAR, to modify that requirement. Thus, Regional Entity must remain in the Applicability section. In all cases, Regional Entity has been spelled out rather than referred to as “RE.”
  - New boilerplate language, recently approved by NERC legal staff, was added to the Effective Dates section of the standard and the Implementation Plan.
- **FAC-003-3:**
  - A typo was found in the Severe VSL for R2; the previous reference to “Transmission Owner” was changed to “responsible entity,” as in all other FAC-003-3 VSLs.
  - New boilerplate language, recently approved by NERC legal staff, was added to the Effective Dates section of the standard and the Implementation Plan.

Other minority comments are addressed alongside their specific comments below.

*Note that if both FAC-003-X and FAC-003-3 are approved in this recirculation ballot, only FAC-003-3 will be presented to NERC's Board of Trustees. FAC-003-X has been modified so that the generator interconnection Facility gap can be quickly addressed in the event that neither FAC-003-2 nor FAC-003-3 is approved by FERC.*

All comments submitted may be reviewed in their original format on the standard's project page:

[http://www.nerc.com/filez/standards/Project2010-07\\_GOTO\\_Project.html](http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html)

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President of Standards and Training, Herb Schrayshuen, at 404-446-2560 or at [herb.schrayshuen@nerc.net](mailto:herb.schrayshuen@nerc.net). In addition, there is a NERC Reliability Standards Appeals Process.<sup>1</sup>

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<sup>1</sup> The appeals process is in the Standard Processes Manual:  
[http://www.nerc.com/files/Appendix\\_3A\\_Standard\\_Processes\\_Manual\\_Rev%201\\_20110825.pdf](http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_Rev%201_20110825.pdf).



## Index to Questions, Comments, and Responses

1. The Project 2010-07 SDT considered Exelon’s appeal in the context of other stakeholder comments submitted in the first successive ballot between October 5 and November 18, 2011, along with advice from NERC staff. The SDT continues to believe that a reference to line of sight is clarifying and makes explicit the SDT’s implicit intent from day one. Thus, it kept the line of sight reference but made a few additional changes for formatting clarity and language consistency. The team also added a footnote to further explain what it means by “line of sight.” Do you agree with these changes? If not, please provide specific alternative language. .... 8

**The Industry Segments are:**

- 1 — Transmission Owners
- 2 — RTOs, ISOs
- 3 — Load-serving Entities
- 4 — Transmission-dependent Utilities
- 5 — Electric Generators
- 6 — Electricity Brokers, Aggregators, and Marketers
- 7 — Large Electricity End Users
- 8 — Small Electricity End Users
- 9 — Federal, State, Provincial Regulatory or other Government Entities
- 10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment											
				1	2	3	4	5	6	7	8	9	10		
1.	Group	Guy Zito	Northeast Power Coordinating Council												X
Additional Member		Additional Organization		Region		Segment Selection									
1.	Alan Adamson	New York State Reliability Council, LLC		NPCC	10										
2.	Greg Campoli	New York Independent System Operator		NPCC	2										
3.	Sylvain Clermont	Hydro-Quebec TransEnergie		NPCC	1										
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.		NPCC	1										
5.	Gerry Dunbar	Northeast Power Coordinating Council		NPCC	10										
6.	Mike Garton	Dominion Resources Services, Inc.		NPCC	5										
7.	Kathleen Goodman	ISO - New England		NPCC	2										
8.	Chantel Haswell	FPL Group, Inc.		NPCC	5										
9.	David Kiguel	Hydro One Networks Inc.		NPCC	1										
10.	Michael R. Lombardi	Northeast Utilities		NPCC	1										

Group/Individual	Commenter	Organization	Registered Ballot Body Segment											
			1	2	3	4	5	6	7	8	9	10		
11. Randy MacDonald	New Brunswick Power Transmission	NPCC 9												
12. Bruce Metruck	New York Power Authority	NPCC 6												
13. Lee Pedowicz	Northeast Power Coordinating Council	NPCC 10												
14. Robert Pellegrini	The United Illuminating Company	NPCC 1												
15. Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC 1												
16. David Ramkalawan	Ontario Power Generation, Inc.	NPCC 5												
17. Brian Robinson	Utility Services	NPCC 8												
18. Saurabh Saksena	National Grid	NPCC 1												
19. Michael Schiavone	National Grid	NPCC 1												
20. Wayne Sipperly	New York Power Authority	NPCC 5												
21. Tina Teng	Independent Electricity System Operator	NPCC 2												
22. Donald Weaver	New Brunswick System Operator	NPCC 2												
23. Ben Wu	Orange and Rockland Utilities	NPCC 1												
24. Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC 3												
2.	Group	Don Jones	Texas Reliability Entity											X
<b>Additional Member Additional Organization Region Segment Selection</b>														
1.	Curtis Crews	Texas Reliability Entity	ERCOT 10											
2.	David Penney	Texas Reliability Entity	ERCOT 10											
3.	Group	Jonathan Hayes	Southwest Power Pool Standards Development Team	X	X	X		X	X					
<b>Additional Member Additional Organization Region Segment Selection</b>														
1.	Jonathan Hayes	Southwest Power Pool	SPP NA											
2.	Robert Rhodes	Southwest Power Pool	SPP NA											
3.	Dan Lusk	Xcel Energy	SPP 1, 3, 5, 6											
4.	Julie Lux	Westar	SPP 1, 3, 5, 6											
5.	Mahmood Safi	OPPD	MRO 1, 3, 5											
6.	Roy Boyer	Xcel Energy	SPP 1, 3, 5, 6											
7.	Mitchell Williams	Western Farmers	SPP 1, 3, 5											
8.	John Pasierb	East Texas	NA - Not Applicable NA											
9.	David Kral	Xcel Energy	SPP 1, 3, 5, 6											
10.	Tom Hesterman	Westar	SPP 1, 3, 5, 6											

Group/Individual	Commenter	Organization	Registered Ballot Body Segment											
			1	2	3	4	5	6	7	8	9	10		
11. Tiffani Lake	Westar	SPP	6, 1, 3, 5											
12. Don Taylor	Westar	SPP	1, 3, 5, 6											
4. Group	Chris Higgins	Bonneville Power Administration	X		X		X	X						
<b>Additional Member Additional Organization Region Segment Selection</b>														
1. Charles	Sheppard		1											
2. Rebecca	Berdahl		3											
5. Group	Mike Garton	NERC Compliance Policy	X		X		X	X						
<b>Additional Member Additional Organization Region Segment Selection</b>														
1. Connie Lowe	NERC Compliance Policy	RFC	5, 6											
2. Michael Crowley	Electric Transmission	SERC	1, 3											
3. Jeff Bailey	Nuclear	MRO	5											
4. Sean Iseminger	F&H	SERC	5											
5. Chip Humphrey	F&H	NPCC	5											
6. Group	WILL SMITH	MRO NSRF	X	X	X	X	X	X						
<b>Additional Member Additional Organization Region Segment Selection</b>														
1. MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6											
2. CHUCK LAWRENCE	ATC	MRO	1											
3. TOM WEBB	WPS	MRO	3, 4, 5, 6											
4. JODI JENSON	WAPA	MRO	1, 6											
5. KEN GOLDSMITH	ALTW	MRO	4											
6. ALICE IRELAND	XCEL(NSP)	MRO	1, 3, 5, 6											
7. DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6											
8. ERIC RUSKAMP	LES	MRO	1, 3, 5, 6											
9. JOE DEPOORTER	MGE	MRO	3, 4, 5, 6											
10. SCOTT NICKELS	RPU	MRO	4											
11. TERRY HARBOUR	MEC	MRO	5, 6, 1, 3											
12. MARIE KNOX	MISO	MRO	2											
13. LEE KITTLESAN	OTP	MRO	1, 3, 4, 5											
14. TONY EDDLEMAN	NPPD	MRO	1, 3, 5											
15. MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6											
16. THERESA ALLARD	MPC	MRO	1, 3, 5, 6											

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
7.	Individual	Antonio Grayson	Southern Company	X		X		X	X				
8.	Individual	Brenda Frazer	Edison Mission Marketing & Trading	X				X					
9.	Individual	John Bee	Exelon	X		X		X	X				
10.	Individual	Ray Phillips	Alabama Municipal Electric Authority				X						
11.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
12.	Individual	Dan Roethemeyer	Dynegy					X					
13.	Individual	Thad Ness	American Electric Power	X		X		X	X				
14.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
15.	Individual	Dale Fredrickson	Wisconsin Electric			X	X	X					
16.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
17.	Individual	Martin Kaufman	ExxonMobil Research and Engineering	X				X					
18.	Individual	Brian Murphy	NextEra Energy, Inc.	X		X		X	X				
19.	Individual	Jean Nitz	ACES Power Marketing						X				
20.	Individual	Patrick Brown	Essential Power, LLC					X					
21.	Individual	Russell A. Noble	Cowlitz County PUD			X	X	X					
22.	Individual	Michelle R. D'Antuono	Ingleside Cogeneration LP					X					

1. **The Project 2010-07 SDT considered Exelon’s appeal in the context of other stakeholder comments submitted in the first successive ballot between October 5 and November 18, 2011, along with advice from NERC staff. The SDT continues to believe that a reference to line of sight is clarifying and makes explicit the SDT’s implicit intent from day one. Thus, it kept the line of sight reference but made a few additional changes for formatting clarity and language consistency. The team also added a footnote to further explain what it means by “line of sight.” Do you agree with these changes? If not, please provide specific alternative language.**

#### Summary Consideration:

Some commenters still do not support the qualifying language for Generator Owners (GOs) or believe that the qualifying language should be worded differently. The SDT continues to believe that the qualifying criteria for GOs are appropriate; it has explained its rationale in depth in the posted [Technical Justification Document](#). The SDT has considered all relevant stakeholder comments, including many possible language options, and is satisfied that it has determined the appropriate language to address the reliability gap.

Some commenters suggested changes to items – including the content of the VSLs and the tables attached to the standard that were outside the scope of the SDT’s work.

Some commenters raised questions about the language differences between FAC-003-X and FAC-003-3 and expressed concern that the language in FAC-003-X could lead to a “null” result whereby the qualifying language is not applied according to the SDT’s intent. The SDT sought to keep the language of 4.3.1 of FAC-003-X consistent with the language in 4.2.1 of FAC-003-X. The SDT does not believe the language in Version X can lead to a “null” result; we believe the language is as clear as possible as written, now that it has been reformatted to better match the formatting in FAC-003-3.

Some commenters questioned whether “clear line of sight” means from a fixed point or from any point along the line. The SDT clarified that it intends for the phrase “from the generating station switchyard fence to the point of interconnection” to mean that there is a clear line of sight from any point along that length of line.

One commenter questioned whether the standard applies to all generator interconnection Facilities that a GO owns if it applies to one of them. The SDT clarified that it intended for the standard to apply on a line by line basis in both FAC-003-X and FAC-003-3. To clarify this, it has reformatted the Applicability section of FAC-003-X to better match the formatting in FAC-003-3.

One commenter asked whether the standard applies to the entirety of an applicable generator interconnection Facility, or just the portion of the line greater than one mile. The SDT clarified that if a GO owns an applicable line, the GO is responsible for the entirety of that line. The SDT believes that this is clear in the standards as written.

One commenter expressed concern that the implementation timeframe is too long. The SDT reminded the commenter that the time frame was based on previous stakeholder comments and the fact that the implementation of Version 0 standards – the transition into which marked the time that TOs needed to begin applying FAC-003 on a mandatory basis – occurred over more than two years. It is therefore reasonable to assume that GOs, having never had to comply with a vegetation management standard, be afforded adequate time to do so.

One commenter continues to find the changes proposed under Project 2010-07 to be unnecessary. As it has in previous consideration of comment reports, the SDT points out that it must act within the scope of the SAR for this project. As mandated by its SAR, the SDT has addressed standards for which there is a reliability gap or possible perception of a gap when it comes to the generator interconnection Facility, as justified in great depth in its [Technical Justification document](#).

The SDT considered all comments received and decided to address typos, improve the formatting of the Applicability section of FAC-003-X, and update the boilerplate language in the Effective Dates sections of the standards and their implementations plans. The SDT has proposed no substantive changes to the standards.

Organization	Yes or No	Question 1 Comment
Ameren Services	Negative	<p>(a) There is no technical basis for the one mile length exemption. In fact, one could argue that a very short line, 300 feet in length, that experienced a fault from a tree at "the end of the circuit", i.e near the switchyard fence, would have much more of an impact on the BES because the fault would be limited by much less impedance.</p> <p>(b) For the GO that owns several lead lines but only one of the lines is greater than one mile in length, does this standard apply to all the lead lines he owns? A response can be affirmative with the current language of the section 4.2.1. If this is not the intent, it should be clarified.</p> <p>(c) It is also unclear in this version if a GO that owned one line that was 1.2 miles in length would have to comply for the entire length of said line, or just 0.2 miles of said line. If the GO is responsible for 1.2 miles, then that</p>

Organization	Yes or No	Question 1 Comment
		<p>argues that the first mile is important and consequently there is no basis for ignoring the first mile on other lines. If the GO is only responsible for 0.2 miles, what is the technical basis to ignore a mile? And would it be the first mile from the switchyard that is ignored, or is the middle mile, or the last mile where it connects to the TO? Or could the GO decide? Or could the GO pick sections of the line that amount to a mile that they can ignore? This seems like something that should be addressed for compliance.</p> <p>(d) The 2 year compliance time line is far too long. There is significant industry evidence that was developed in the drafting of Version 2 that supports a one year compliance time-line for new lines. This is evidenced in Version 2. Thus there is no basis for the 2 years</p>
<p><b>Response: Thank you for your comment. The SDT continues to believe that the qualifying criteria for GOs are appropriate; it has explained its rationale in depth in the posted <a href="#">Technical Justification Document</a>. The SDT has considered all relevant stakeholder comments and is satisfied that it has determined the appropriate language to address the reliability gap.</b></p> <p><b>The SDT intended for the standard to apply on a line by line basis in both FAC-003-X and FAC-003-3. To clarify this, it has reformatted the Applicability section of FAC-003-X to better match the formatting in FAC-003-3.</b></p> <p><b>If a GO owns an applicable line, the GO is responsible for the entirety of that line. The SDT believes that this is clear in the standards as written.</b></p> <p><b>With respect to the Implementation Plan, the SDT reminds Ameren that the time frame was based on previous stakeholder comments and the fact that the implementation of Version 0 standards – the transition into which marked the time that TOs needed to begin applying FAC-003 on a mandatory basis – occurred over more than two years. It is therefore reasonable to assume that GOs, having never had to comply with a vegetation management standard, be afforded adequate time to do so.</b></p>		
BC Hydro and Power Authority	Negative	<p>“BC Hydro agrees with the revisions to FAC-003-3 and would vote Affirmative except for the following two items.</p> <p>One: The FAC-003-2 adopted by the NERC Board of Trustees had a significant change to what was voted on in Draft 6 in the Table of Compliance Elements (R1 and R2). In the table on Page 13 of the version</p>



Organization	Yes or No	Question 1 Comment
		<p>adopted by the NERC Board of Trustees on November 3, 2011, the VSLs were changed and the staff proposed violation severity levels were adopted and the review team recommendations were rejected. Therefore, there is no Low or Moderate VSLs for these two violations only High and Severe. This was rejected earlier by a number of utilities including BC Hydro and was not in the version 6 draft that was voted for on the last ballot. This change as adopted is a concern as it expects a level of program perfection that seems unrealistic. It is also at odds with the Rationale for R1 and R2 outlined on Page 32 of the standard “Guideline and Technical Basis” section which gives an explanation for the increasing levels of violation severity. Program failures that were deemed to be “unusual conditions in an otherwise sound program” or “not adequately addressed by the program” formerly rated as Lower or Moderate VSL are now rated as High. It also extends the severity of the violation beyond what is currently in FAC-003-1 although the levels of non-compliance are not strictly comparable between versions. This change is carried on in the Draft FAC-003-3.</p> <p>Two: Table 2 (pg. 30 and 31 of FAC-003-3 Draft 3) for Minimum Vegetation Clearance Distances for AC Voltages now includes clearance calculations for 287 kV which is good and was something BC Hydro asked for. However, the calculations don’t seem to be correct as the limits are higher than for 345kV. BC Hydro recommends either providing an explanation as to why these limits seem to be out of sequence to increasing voltage or recalculate them.”</p>
<p><b>Response:</b> Thank you for your comment. The SDT's SAR is very limited in scope (determining which additional standards should apply to a GO/GOP). The SDT made no changes to the VSLs and simply included the FAC-003-2 VSLs that were approved by NERC’s BOT, as those are the VSLs that will be filed with FERC. Similarly, the SDT made no changes to Table 2, as that would also have been outside its scope; the SDT exclusively made changes that would add GOs or GOPs to standard requirements or applicability sections, and changes that would bring the standard up to date according to current NERC templates. No change made.</p>		

Organization	Yes or No	Question 1 Comment
ComEd	Negative	Please refer to Exelon's comments submitted in the electronic comment form
PECO Energy	Negative	Please refer to Exelon's comments submitted in the electronic comment form
Gulf Power Company	Negative	See comments submitted via the electronic comments form by Antonio Grayson.
Mississippi Power	Negative	See comments submitted via the electronic comments form by Antonio Grayson.
Alabama Power Company	Negative	See comments submitted via the electronic comments form by Antonio Grayson.
Utility Services, Inc.	Negative	The applicability language under Version X is not the same as the language in Version 3. We do not believe that applicability language in Version X can ever result in a “True” logical outcome whereas the language in Version 3 can. We understand the intent; however, applying the specific language using the logical "AND" in the applicability portion of the standard will always come out with a null result. We suggest the SDT adopt the applicability language in Version 3 in Version X.
<p><b>Response: Thank you for your comment. The SDT sought to keep the language of 4.3.1 of FAC-003-X consistent with the language in 4.2.1 of FAC-003-X. The SDT does not believe the language in Version X can lead to a “null” result; we believe the language is as clear as possible as written now that it has been reformatted to better match the formatting in FAC-003-3. No change made.</b></p>		
Xcel Energy, Inc.	Negative	This project is counter-productive to the efforts of the Protection System Maintenance and Testing Standard Drafting Team that concurrently has

Organization	Yes or No	Question 1 Comment
		PRC-005-2 posted for comment and successive ballot.
<p><b>Response: Thank you for your comment. The SDT believes this comment was submitted in response to PRC-005 and will address it with comments received under that standard.</b></p>		
SERC Reliability Corporation	Negative	<p>We have concern that if this passes there will be BES Elements that will not be covered by the vegetation management standard that are currently included in the standards and that this determination is based solely on ownership and not risk to reliability. SERC supports BES reliability and as vegetation management was identified as a significant contributor to the 2003 Blackout we do not support a revision that would create a gap in the results-based, defense-in-depth approach that has been determined to be necessary for the reliable operation of the interconnected transmission network.</p>
<p><b>Response: Thank you for your comment. GOs are not currently covered under any vegetation management requirements, so the SDT does not understand the comment about removing coverage for BES Elements “that are currently included in standards.” The applicability to TOs, the entity currently subject to vegetation management requirements, is not changing. The SDT recognizes that in many cases, generation Facilities are (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale for exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. No stakeholder has commented that there are similarly situated transmission facilities.</b></p>		
Southern Company	No	<p>The requirement as worded implies or could be interpreted to mean one's line of site would have to originate at the generating station switchyard fence. The "clear line of site" should also include that from a roadway that travels in proximity to the line. Such a roadway's purpose would likely include access to the line for inspections, maintenance, travel from the plant to the transmission substation, etc. Since the terrain between the generating station switchyard fence and the point of interconnection could obscure the view from the fence, the clear line of site from such a roadway</p>

Organization	Yes or No	Question 1 Comment
		<p>should be allowed. The requirement should be revised to read, "...or (2) does not have clear line of sight<sup>1</sup> from the generating station switchyard fence or a roadway to the point of interconnection with a Transmission Owner's Facility."</p>
<p><b>Response: Thank you for your comment. The SDT appreciates this discussion, and had many similar discussions during its own deliberations. The SDT intends for the phrase "from the generating station switchyard fence to the point of interconnection" to mean that there is a clear line of sight from any point along that length of line. The SDT has considered all relevant stakeholder comments and is satisfied that it has determined the appropriate language to address the reliability gap. No change made.</b></p>		
<p>Southwest Power Pool Standards Development Team</p>	<p>No</p>	<p>Clear line of sight" means the distance that can be seen by the average person "standing at ground level "without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.</p>
<p><b>Response: Thank you for your comment. The SDT has considered all relevant stakeholder comments and is satisfied that we have determined the appropriate language to address the reliability gap.</b></p>		
<p>Cowlitz County PUD</p>	<p>No</p>	<p>Cowlitz must agree with Exelon’s position inasmuch that the vantage point must be related to the generating station switchyard maintenance or the operation and maintenance of the generation plant itself, and afford a clear perspective of vegetation proximity. Cowlitz also agrees with the SDT’s line of sight clarifying verbiage. However, restricting the vantage point to the generating station switchyard fence does not encompass the spirit of the exclusion. A short one-mile transmission interconnection line - from the generating station switchyard to the interconnection point - that is frequently viewed during the operation and maintenance of the generation plant itself should be the crux of the exemption.</p> <p>The exact location, i.e., the generating station switchyard fence, of the vantage point is not the make or break of whether the interconnection line will be routinely inspected by default. As an example, consider a hydro project where the generating station switchyard may be located near the</p>

Organization	Yes or No	Question 1 Comment
		<p>tailrace inside a canyon. From the fence line of this particular switchyard, only the interconnection line traversing up the canyon wall is visible. However, topside of the dam where maintenance and operational personnel must daily traverse under the interconnection line to access the powerhouse and switchyard may afford a clear view of both the generating station switchyard below and the interconnection station which includes the whole interconnecting line in-between.</p> <p>Further, if parts of the interconnecting line is viewable in two or even three vantage points beneath the interconnection line during the normal transit to and from the generating station switchyard, the sum of which comprises the whole line, can this not also meet the spirit of the exclusion?</p> <p>Conversely, Cowlitz does not hold that any vantage point should be acceptable. Any vantage point that must require special effort to access no matter the ease is not acceptable. Also, a perpendicular view of a line (not under or near) complicates perception of the proximity of vegetation to a line. Views parallel down the right-of-way maximizes perception of vegetation proximity.</p> <p>Further, a long line that is fully viewable during transit to and from the generation plant increases the chance of hidden vegetation encroachment. Cowlitz strongly opposes any trivializing of reliability compliance collateral damage. Forcing compliance activities with no reliability return must be avoided wherever possible. As a stakeholder with limited time to invest reviewing all the comments submitted, Cowlitz offers an apology to Exelon for missing their initial comment. Cowlitz commends Exelon’s persistence in this matter.</p> <p>***Suggested language: ...or (2) do not have a clear line of sight (leave the footnote in place) up and/or down from a single vantage point within the transmission right-of-way where both the origin at the generating station switchyard and the termination interconnection point with the Transmission</p>

Organization	Yes or No	Question 1 Comment
		Owner’s Facility can be seen, and where operations or maintenance personnel frequent on foot during normal generation plant or generating station switchyard access is made...
<p>Response: Thank you for your comment. The SDT appreciates this discussion, and had many similar discussions during its own deliberations. The SDT intends for the phrase “from the generating station switchyard fence to the point of interconnection” to mean that there is a clear line of sight from any point along that length of line. We do not believe that adding the language you suggest necessarily adds clarity, and we’re concerned that it may raise additional questions. In sum, the SDT has considered all relevant stakeholder comments and is satisfied that we have determined the appropriate language to address the reliability gap. No change made.</p>		
Exelon	No	<p>Exelon disagrees with the current proposed draft of FAC-003-3/X because the reference to a “clear line of sight from the generating station switchyard fence to the point of interconnection” does not clarify the Standard and is unsupported by any technical basis. Furthermore, the definition of “clear line of sight” added by the SDT does not address or remedy the substantive concerns raised in Exelon’s appeal.</p> <p>Exelon reiterates that the SDT should base the applicability of the Standard on the length of the transmission line, a measurable component of the bulk electric system, and remove all references to a “clear line of sight.” This approach is consistent with previous draft versions of FAC-003 proposed by the SDT and the Ad Hoc Group and the recent recommendation of the NERC Vice President of Standards and Training in response to Exelon’s appeal.</p> <p>Alternatively, if the “clear line of sight” verbiage remains, the Standards should be clarified to remove the requirement that the line of sight be established from “the generating station switchyard fence to the point of interconnection” and to add a requirement or clarify that “clear line of sight” for lines of one mile or less can include observation of the length of the transmission lines from various vantage points within the owner controlled property. The SDT states in the “Background” section of the</p>

Organization	Yes or No	Question 1 Comment
		<p>Unofficial Comment Form that “a reference to the line of sight is clarifying and makes explicit the SDT’s implicit intent from day one.”</p> <p>Yet, the SDT offers no support for its “implicit intent from day one,” and a review of the history for these Standards certainly does not support an “implicit intent from day one” to require a clear line of sight from a fixed location, let alone the generating station switchyard fence, to the point of interconnection. The Technical Justification document posted in September 2011 (p. 3) refers to the Ad Hoc Group’s original thought to exclude from the Standards any transmission lines that were “less than two spans [long] (generally one half mile from the generator property line).” In agreeing “with that intended exclusion in principle,” the SDT explained (p. 3) that, “[a]fter reviewing formal comments, the SDT agreed to revise the exclusion so that it applies to a Facility [transmission line] if its length is ‘one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard’ to approximate line of sign [sic] from a fixed point,” (the fixed point being the fenced area of the generating station switchyard). From the start, the Ad Hoc Group and SDT focused on the length of the transmission line (either a half mile as proposed by the Ad Hoc Group or a mile as proposed by the SDT) as the proxy for line of sight, the presumption being that up to a certain distance, the overhead line is in the line of sight at various locations throughout the Generator Owner’s property and reasonably subject to being managed through normal day-to-day plant activities.</p> <p>The SDT has not, until the most recent iteration of the Standards, focused on requiring a “clear line of sight from the generating station switchyard fence to the point of interconnection.” As support for adding the “clear line of sight” requirement to the FAC-003-3/X Standards in December 2011, the SDT noted as follows: “We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and</p>

Organization	Yes or No	Question 1 Comment
		<p>any discretion on the part of a Generator Owner or an auditor.” With the addition of an explicit line of sight reference here, the SDT believes it has clarified its original intent. (Side bar comments to FAC-003-3, Section 4.3.1 (December 1, 2011); FAC-003-X, Section 4.3.1 (December 1, 2011)).</p> <p>This explanation does nothing more than (1) reiterate the point the SDT has maintained throughout the entire drafting process, namely that “the one mile length” of a transmission line “is a reasonable approximation of line of sight,” and (2) explain that the SDT included a “fixed starting point” (the fenced area of the generation station switchyard) from which to measure the length of the transmission line to address stakeholder concerns about excessive Generator Owner discretion with respect to the location from which to take a measurement and inconsistent application of the Standards.</p> <p>Again, the SDT’s “intent” (implicit or otherwise) “from day one” has nothing to do with establishing a “clear line of sight from the generating switchyard fence to the point of interconnection.” In addition, requiring a “clear line of sight from the generating station switchyard fence to the point of interconnection” is technically unsupported. The SDT just added the requirement for a “clear line of sight to the point of interconnection” language without considering the implications of why such a change was required or reasonable. While a specific fixed starting point (the generating station switchyard fence) and end point (the point of interconnection) may make sense for establishing a starting and ending point from which to measure the length of the transmission line (the one-mile limitation), it does not make sense when considering a clear line of sight, especially in light of stakeholder comments and the SDT’s repeated acknowledgment that in many cases, generation Facilities are either (1) staffed and the overhead portion is within the line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that</p>



Organization	Yes or No	Question 1 Comment
		<p>these qualifiers represent a reasonable and appropriate risk prevention approach.(Consideration of Comments, Generator Requirements at the Transmission Interface, Project 2010-07 (for November 9, 2011 successive ballot), p. 1; Technical Justification Resource Document (posted March 2012), p. 3.)</p> <p>By inserting the “clear line of sight” requirement now without modifying the fixed starting point, the SDT completely ignores its unequivocal acknowledgment that generation Facilities are unique in the sense that personnel can see the line from various locations within the owner controlled area and many generation Facilities are over paved surfaces. The absence of a technical justification for imposing a “clear line of sight” is illustrated by the following example.</p> <p>A Generator Owner transmission line leaving the generating station could take a “dog leg” turn (the line turns at one of the towers). Standing at the tower in this example, an individual would have a clear line of sight of the entire line to either end of the short-distance line (to the end leaving the station and to the end terminating at the point of interconnection). Since the generating Facility is within the Generator Owner’s property line or controlled area and consistently staffed by personnel who patrol the owner controlled area, the line can be observed and maintained by staff in the same manner as any other short distance line with a “clear” line of sight from the “generating station switchyard fence to the point of interconnection.” Moreover, to the extent a portion or the entire length of the line travels over paved surfaces or structures, any barriers or obstacles to a clear line of sight will not be caused by vegetation, as discussed in FAC-003-3/X but, rather, by equipment, components, or structures. Clearance between generator lines and structures is already covered in other NERC Standards. For those lines that do travel over areas of vegetation, the regular personnel monitoring and surveillance of the areas over which the lines travel provides reasonable assurance of protection from vegetation</p>

Organization	Yes or No	Question 1 Comment
		<p>related events.</p> <p>Rather than clarifying the Standards, the SDT has introduced more ambiguity into the Standards. The addition of the “generating station switchyard fence” as the point of reference for a clear line of sight adds more confusion than it solves by introducing a variable that will be left to the discretion of generator owner and an auditor. What is the definition of a “generating station switchyard fence?” As Exelon noted in its Appeal and at least one other Registered Entity noted in its Comments for the first successive ballot (Consideration of Comments posted March 2012, p. 38), some generation facilities do not have generating switchyards or generating switchyard fences. A requirement that there be a clear line of sight from the “generating switchyard fence” is meaningless in cases where no such switchyard or fence exists. Is it the fence surrounding the generating unit or is it meant to refer to the fence surrounding the Transmission Owner’s associated switchyard and relay house? What if there are multiple physical fence lines between the generating unit and the point of interconnection? In addition, by introducing a point of reference that is not a physical component or measurable reference of the bulk electric system, what precludes the Generator Owner from arbitrarily moving the fence line to avoid applicability? Also lacking in clarity is the addition of a footnote defining “clear line of sight” to mean “the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.” Generation Owners will be left to determine what constitutes an “average person,” a “clear day,” and “special instrumentation.”</p> <p>For all these reasons, Exelon requests that the SDT base the applicability of the Standard on the length of the transmission line, a measurable component of the bulk electric system, and remove all references to a “clear line of sight.” Alternatively, if the “clear line of sight” verbiage remains, the Standards should be clarified to remove the requirement that</p>

Organization	Yes or No	Question 1 Comment
		<p>the line of sight be established from “the generating station switchyard fence to the point of interconnection” and to add a requirement or clarify that “clear line of sight” for lines of one mile or less can include observation of the length of the transmission lines from various vantage points within the owner controlled property.</p>
<p><b>Response:</b> Thank you for your comment. The SDT appreciates this discussion, and had many similar discussions during its own deliberations. We maintain that the addition of the reference to “clear line of sight” is clarifying and helps support the rationale behind the one mile exemption. A line less than one mile that passes through a dense grove should not be exempt from this standard, but a line that is less than one mile and is either (1) staffed and within line of sight or (2) over a paved surface <i>should</i> be exempt.</p> <p>The SDT intends for the phrase “from the generating station switchyard fence to the point of interconnection” to mean that there is a clear line of sight from any point along that length of line. We do not believe that adding a reference to a fixed vantage point necessarily adds clarity, and we’re concerned that it may raise additional questions. In sum, the SDT has considered all relevant stakeholder comments and is satisfied that we have determined the appropriate language to address the reliability gap. No change made.</p>		
Texas Reliability Entity	No	<p>In FAC-003-X:</p> <ol style="list-style-type: none"> <li>1. We appreciate that you took Regional Entity out of the Applicability section, but there is still a Requirement (R4) that applies to the Regional Entity. Is that Requirement intended to be enforceable against the Regional Entities? We suggest removing Requirement R4.</li> <li>2. In Part D.1.1, only the Regional Entity should be listed as Compliance Monitor, since the Regional Entity has been removed as an Applicable entity.</li> <li>3. In the Purpose section, update the reference to NERC (use “Corporation” instead of “Council”), and capitalize “Rights-of-Way” since it is a defined term.</li> </ol>

Organization	Yes or No	Question 1 Comment
		<p>4. We suggest that you spell out “Regional Entity” in Applicability part 4.2.1.</p> <p>5. In the implementation plan, the reference to “R3” should be corrected to “R1” in the following sentence: “In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees adoption.”</p> <p>In FAC-003-3:</p> <p>6. There is no Compliance Monitor listed on page 17. At least the Regional Entity should be listed here.</p> <p>7. In the Severe VSL for R2, replace “Transmission Owner” with “responsible entity.”</p> <p>8. In the Severe VSL for R1 and R2, remove “active transmission line” before “ROW.” That phrase is confusing in the VSLs because it does not appear in the requirements, and it is not clear whether it is intended to change the requirements.</p> <p>9. In Table 2 (Alternating Current - meters AND Direct Current) the footnote references are wrong. We think they should be 9 and 10, rather than 7 and 8.</p> <p>10. In Table 2 (Direct Current), the column headings are wrong. Only the first column heading should refer to voltage. The rest should refer to MVCD.</p>
<p><b>Response: Thank you for your comment.</b></p> <ol style="list-style-type: none"> <li><b>The SDT has reverted back to the original Applicability (which included the Regional Entity) because deleting a requirement is outside the scope of this drafting team.</b></li> <li><b>Because the Regional Entity was returned to the Applicability section, the second bullet in section D1.1 must remain.</b></li> <li><b>Changes made.</b></li> <li><b>Regional Entity has been spelled out in all cases.</b></li> </ol>		

Organization	Yes or No	Question 1 Comment
<p>5. Change made.            6. The Compliance Enforcement Authority section has been updated as suggested.            7. Change made.            8. Modifying the VSLs beyond the change from “Transmission Owner” to “responsible entity” is not within the scope of the SDT, and these VSLs have already been approved by NERC’s BOT.            9. These are 9 and 10 in both the clean version and the redline version.            10. The Project 2010-07 SDT did not modify this table.</p>		
Manitoba Hydro	No	<p>Manitoba Hydro does not support the changes being proposed in Project 2010-07. If a Generator Owner is required to register as a TO, all the Requirements applicable to a TO should apply. There is no need to change specific Reliability Standards to allow the Generator Owner to perform only selected TO functions. For additional information, please see Manitoba Hydro's comments submitted in the comment period ending November 18, 2011. Manitoba Hydro does not believe that the SDT fully addressed our concerns in their responses to our comments in that commenting period.</p>
<p><b>Response:</b> Thank you for your comment. Under the SDT’s changes, GOs are not going to be required to register as TOs, so this comment does not apply.</p> <p>To reiterate our comments in previous comment reports, the intent of the SDT’s SAR is to address all reliability gaps associated with ownership or operation of an interconnection Facility by a generation entity (GO/GOP). The SDT determined that it should first address “low-hanging fruit” and believes these to be sole-use Facilities (see posted examples under “Supporting Materials” posted alongside the December ballot) – that is, a Facility used to connect one or more generators to a Facility owned or operated by a transmission entity (TO/TOP). Through our deliberations, we came to the conclusion that an interconnection Facility owned or operated by a GO or GOP that is more complex would likely require specific analysis and that such analysis would most likely be outside the scope of this SDT.</p> <p>The SDT also refers the commenter to the document titled <a href="#">Project 2010-07: Generator Requirements at the Transmission Interface Background Resource Document</a>.</p>		
Liberty Electric Power LLC	No	The "line of sight" should be removed. It opens up the entity to a finding of

Organization	Yes or No	Question 1 Comment
		non-compliance if a temporary blockage of line of sight should occur.
<p>Response: Thank you for your comment. We maintain that the addition of the reference to “clear line of sight” is clarifying and helps support the rationale behind the one mile exemption. A line less than one mile that passes through a dense grove should not be exempt from this standard, but a line that is less than one mile and is either (1) staffed and within line of sight or (2) over a paved surface <i>should</i> be exempt. Nothing in the proposed standard prohibits an entity from self-imposing the requirements contained within in order to mitigate any perceived risk of potential non-compliance. No change made.</p>		
Northeast Power Coordinating Council	No	<p>The Applicability language used in FAC-003-X is different from that used in FAC-003-3. The language used in FAC-003-X uses “and” in several places which leads to confusion and a probable “null” result, whereas the language in FAC-003-3 is more straightforward and makes use of “or”. The FAC-003-3 applicability language should be used in FAC-003-X. The explanation of what is meant by line of sight should be incorporated in the Applicability Section wording as standards, at NERC’s direction, are supposed to be getting away from the use of footnotes.</p>
<p>Response: Thank you for your comment. The SDT sought to keep the language of 4.3.1 of FAC-003-X consistent with the formatting in 4.2.1 of FAC-003-X. The SDT does not believe the language in Version X can lead to a “null” result; we believe the language is as clear as possible as written now that the formatting has been updated to better reflect the formatting in FAC-003-3. No change made.</p>		
NextEra Energy, Inc.	No	<p>Under the line of sight approach, a generation lead would be exempt from the requirements of FAC-003-3 if personnel can see the generation lead corridor and the generation lead is less than a mile. The rationale provided to support of this proposal is that “Stakeholders have generally supported the rationale for exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit.”</p> <p>However, there is no data that supports that generation leads of less than a mile are categorically not subject to vegetation contacts and outages. Further, in practice this approach will unduly discriminate against longer</p>

Organization	Yes or No	Question 1 Comment
		<p>generator leads, many of which are associated with renewable energy resource, such as wind and solar.</p> <p>NextEra Energy Inc. (NextEra) believes a more technically sound approach is that all generator leads be subject to FAC-003-3, with the opportunity to be exempted from FAC-003-3 regulation upon an affirmative demonstration that no vegetation threat exists.</p> <p>To implement this approach, NextEra proposes that FAC-003-3 applicability 4.3.1 be revised to read as follows: “Overhead transmission lines, including generation leads, beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner and are:4.3.1.1. Operated at 200kV or higher; or 4.3.1.2. Operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator; or. 4.3.1.3. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.”</p> <p>NextEra would also propose to add a new section 4.3.2 that reads as follows:”If a Generator Owner or Transmission Owner can demonstrate that the entire Right-of-Way is paved or otherwise devoid of vegetation, and reasonably expected to remain so, the Generation Owner or Transmission Owner is exempt from FAC-003-3.”</p> <p>In addition, NextEra proposes that the drafting team consider a megawatt (MW) threshold for a generating plant from both a stand-alone and aggregate bases. For example, it is unlikely that vegetation contact tripping a 50 megawatt generator (or a generator of 100 MWs in the aggregate) connected to a robust transmission system with a large amount of load and generation will adversely impact reliability.</p> <p>Thus, NextEra proposes the addition of a provision that exempts a generation lead for stand-alone generators of 50 MWs and below and</p>

Organization	Yes or No	Question 1 Comment
		<p>generators in the aggregate of 100 MWs and below, unless there is an affirmative request for the generator to comply with FAC-003-3 by a Transmission Operator or Reliability Coordinator. Such a provision could read as follows: "Unless a Transmission Operator or Reliability Coordinator requests in writing that a stand-alone generator of 50 Megawatts (MWs) or below (with a 200 kV or above generation lead) or a generator in the aggregate of 100 MWs or below (with a 200 kV or above generation lead) comply with FAC-003-3, these classes of generators and their associated generation leads are exempt from complying with FAC-003-3. In the event a Transmission Operator or Reliability Coordinator requests in writing that a stand-alone generator of 50 Megawatts (MWs) or below (with a 200 kV or above generation lead) or a generator in the aggregate of 100 MWs or below (with a 200 kV or above generation lead) comply with FAC-003-3, the associated registered entity shall have one-year from the date of the written correspondence to come into compliance with FAC-003-3."</p>
<p><b>Response:</b> Thank you for your comment. The SDT appreciates this discussion, and had many similar discussions during its own deliberations. We maintain that the addition of the reference to "clear line of sight" is clarifying and helps support the rationale behind the one mile exemption. A line less than one mile that passes through a dense grove should not be exempt from this standard, but a line that is less than one mile and is either (1) staffed and within line of sight or (2) over a paved surface <i>should</i> be exempt. And because there are many GOs whose lines would fall into these categories, the SDT believes the exemption is necessary and prevents GOs with little to no reliability risk from incurring undue cost and compliance risk in the development and maintenance of a vegetation management plan. In sum, the SDT has considered all relevant stakeholder comments and is satisfied that we have determined the appropriate language to address the reliability gap. No change made.</p>		
Dynergy	No	<p>Using the switchyard fence is to restrictive. There could be to many different layouts to keep it fair for all GO's. For example, there could be an obstruction if limited to standing at the existing switchyard fence but if one were to move a short distance away (i.e. corner of GO's building) then it could be possible to see both ends of the tie line. This would also meet the intent of the added language since it is now within line of sight. I</p>



Organization	Yes or No	Question 1 Comment
		<p>recommend deleting "switchyard fence". Also, in order to account for a GO not being able to dictate what happens inside a TO's switchyard, I recommend adding "entry or" between "of" and "interconnection".</p>
<p><b>Response:</b> Thank you for your comment. The SDT appreciates this discussion, and had many similar discussions during its own deliberations. The SDT considered many options for a starting point, and believes that using the fixed starting point of the switchyard fence is best for eliminating confusion and any discretion on the part of a Generator Owner or an auditor. The SDT intends for the phrase “from the generating station switchyard fence to the point of interconnection” to mean that there is a clear line of sight from any point along that length of line. In sum, the SDT has considered all relevant stakeholder comments and is satisfied that we have determined the appropriate language to address the reliability gap. No change made.</p>		
<p>Wisconsin Electric; Wisconsin Electric Power Co.; Wisconsin Electric Power Marketing; Wisconsin Energy Corp.</p>	<p>No</p>	<p>We strongly oppose the addition of the “clear” line of sight criteria to the Applicability. The report of the GOTO Task Force, as well as prior draft revisions to FAC-003, included a test based solely on circuit length, which is sufficient in our view to assure that the BES is not at risk due to vegetation issues on generator tie lines. The expansion to include short tie lines, including those entirely on the Generator Owner’s property which may not meet the line of sight qualifier, has no benefit to reliability. Rather, the expanded applicability and the requirement for a formal vegetation management program in these cases will consume resources for compliance that are better used for actual reliability improvements.</p>
<p><b>Response:</b> Thank you for your comment. The SDT appreciates this discussion, and had many similar discussions during its own deliberations. We maintain that the addition of the reference to “clear line of sight” is clarifying and helps support the rationale behind the one mile exemption. A line less than one mile that passes through a dense grove should not be exempt from this standard, but a line that is less than one mile and is either (1) staffed and within line of sight or (2) over a paved surface <i>should</i> be exempt. The SDT has considered all relevant stakeholder comments and is satisfied that we have determined the appropriate language to address the reliability gap. No change made.</p>		
<p>ExxonMobil Research and Engineering</p>	<p>No</p>	<p>While it is clear that the SDT is attempting to include those facilities owned by Generator Owners that travel long distances down right-of-ways, the</p>

Organization	Yes or No	Question 1 Comment
		<p>applicability section of FAC-003-X and FAC-003-3, as written, require industrial complexes with cogeneration facilities to develop Transmission Vegetation Management Programs for generator lead lines that are not exposed to vegetation.</p> <p>Industrial cogeneration location is typically chosen based on the availability of fuel, need for steam, or availability of real estate. This can result with the generation facilities (including the GSU transformer substation) being located deep within the plant with long cable routes and multiple substation connections between the GSU transformer substation and utility interconnection facility located near the perimeter of the industrial complex’s fence line. Additionally, the routes of these generator lead lines fundamentally differ in nature from a typical IPP’s generator lead line route. Since they are located within the fence line of an industrial complex, the routes rarely contain vegetation; are frequently travelled by plant personnel; rarely run in straight lines (i.e. no single line of sight); and frequently terminate at a facility located at the fence line of the industrial complex where a transmission company takes ownership of the power lines that leave the industrial complex. Furthermore, the use of the term “generating station switchyard” may result in inconsistent enforcement of the Transmission Vegetation Management Program Reliability Standard as the use of the term implies there is only one substation located within a Generator Owner’s complex. Typically, there are multiple substations that connect an industrial complex’s generator lead-line to the utility interconnection facility located near the perimeter of the industrial complex’s fence line. The two obvious interpretations for the “generating station switchyard” are the substation that is directly connected to the generator’s GSU, and the utility interconnection facility. The concerns raised by NERC and FERC staff related generator owned transmission like assets originate with those conductors that leave the Generator Owner’s complex’s fence line and travel long distances down vacant right-of-ways,</p>

Organization	Yes or No	Question 1 Comment
		<p>and, therefore, the applicability of those Reliability Standards that apply to transmission facilities should start with the fence line.</p> <p>Since the Bulk Electric System is contiguous, reliability concerns related to the facilities between the GSU transformer substation and utility interconnection facility are covered by those Reliability Standards that apply to Generator Owners and Generator Operators. In order to account for the different nature of industrial complex's generation facilities, the SDT should consider re-phrasing the applicability section of FAC-003-X and FAC-003-3 to start counting the length of a generator lead line at the fence line of the Generator Owner's complex and not the generating station switchyard.</p>
<p><b>Response: Thank you for your comment. The SDT appreciates this discussion, and had many similar discussions during its own deliberations. The SDT considered many options for a starting point, and for language in general within this qualifier, and it believes that using the fixed starting point of the switchyard fence is best for eliminating confusion and any discretion on the part of a Generator Owner or an auditor. In sum, the SDT has considered all relevant stakeholder comments and is satisfied that we have determined the appropriate language to address the reliability gap, while exempting the most common lines with little to no reliability risk for a vegetation issue. No change made.</b></p>		
<p>City of Bartow, Florida; City of Clewiston; Florida Municipal Power Agency; Beaches Energy Services</p>	<p>Affirmative</p>	<p>Although we are supporting the change, the added applicability language for GOs is ambiguous as to whether the qualifier "operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region" applies to both portions of the applicability (e.g., 1) &gt; 1 mile and 2) no clear line of sight), or just to the second no clear line of sight applicability. FMPA assumes that the qualifier applies to both. We recommend re-arranging of the sentence to make this clearer by moving the qualifier to the beginning of the sentence instead of the end of the sentence.</p>
<p><b>Response: Thank you for your comment. The SDT agrees that the qualifier applies to both (1) and (2) in the qualifier language and used that language formatting to keep the formatting of 4.2.1 of FAC-003-X consistent with 4.1.1 of FAC-003-X. No change</b></p>		

Organization	Yes or No	Question 1 Comment
made.		
American Wind Energy Association	Affirmative	<p>AWEA supports the modifications in this standard, along with the other standards modification under Project 2010-07, as a reasonable approach to addressing the perceived reliability concerns with generator tie lines. We believe a consistent approach for all Generator Owners and Generator Operators that does not require registration as a Transmission Owner or Transmission Operator is the most efficient and effective way to address these concerns.</p>
<p><b>Response: The SDT thanks you for your comment and support.</b></p>		
BrightSource Energy, Inc.	Affirmative	<p>BrightSource would like to thank the SDT for the effort in developing the standard. Our comment is more on providing more clarification. Depending on the agreements between the TO and the GO, the Point of Interconnection is not necessarily the point of change of ownership of the transmission facilities. For example, the GO may own the portion of the Gen-tie from the generating plant to the last tower outside the TO’s substation and the TO owns the line drop from the last tower to the termination equipment inside the TO substation. So to avoid confusion later we suggest that we modify P4.3.1 by adding “to the point of change of ownership or” as follows: “4.3.1. Generator Owner that owns an overhead transmission line(s) that (1) extends greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of change of ownership or to the point of interconnection with a Transmission Owner’s Facility or (2) does not have a clear line of sight<sup>1</sup> from the generating station switchyard fence to the point of interconnection with a Transmission Owner’s Facility and is operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.” Thank you.</p>

Organization	Yes or No	Question 1 Comment
<p><b>Response: The SDT thanks you for your comment and support. The SDT considered many different language choices for its qualifying language, and it believes that “point of interconnection” is a clear phrase that will be understood and appropriately applied. No change made.</b></p>		
<p>Indiana Municipal Power Agency</p>	<p>Affirmative</p>	<p>IMPA supports the change, but would add the comment that the added applicability language for GOs is ambiguous as to whether the qualifier "operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region" applies to both portions of the applicability which are 1) &gt; 1 mile and 2) no clear line of sight), or just to the second portion for no clear line of sight applicability. IMPA assumes that the qualifier applies to both. We recommend reorganizing the sentence to make this more clear by moving the qualifier to the beginning of the sentence.</p>
<p><b>Response: Thank you for your comment. The SDT agrees that the qualifier applies to both (1) and (2) in the exemption language and used that language formatting to keep the formatting of 4.2.1 of FAC-003-X consistent with the formatting in 4.1.1 of FAC-003-X. No change made.</b></p>		
<p>Nebraska Public Power District</p>	<p>Affirmative</p>	<p>NPPD joins the comments submitted by the MRO NSRF (Midwest Reliability Organization - NERC Standards Review Forum)</p>
<p>Midwest Reliability Organization</p>	<p>Affirmative</p>	<p>Please refer to comments made by MRO NSRF.</p>
<p>Muscatine Power &amp; Water</p>	<p>Affirmative</p>	<p>Please see comments submitted by the MRO NERC Standards Review Forum.</p>
<p>Lakeland Electric</p>	<p>Affirmative</p>	<p>See FMPA comments</p>
<p>Great River Energy</p>	<p>Affirmative</p>	<p>See NSRF comments</p>
<p>Bonneville Power Administration</p>	<p>Yes</p>	<p>BPA has no other comments or concerns at this time.</p>

Organization	Yes or No	Question 1 Comment
NERC Compliance Policy	Yes	<p>Dominion offers the following comments on the Implementation Plan for FAC-003-3:</p> <ol style="list-style-type: none"> <li>1. The last paragraph on page 2 refers to FAC-003-3 Requirement 1.3. FAC-003-3 does not appear to contain a Requirement 1.3; therefore, Dominion recommends that the reference in the Implementation Plan be clarified.</li> <li>2. The 3rd paragraph on page 3 refers to FAC-003-3 Requirement 1.2. FAC-003-3 does not appear to contain a Requirement 1.2; therefore, Dominion recommends that the reference in the Implementation Plan be clarified.</li> </ol>
<p><b>Response: Thank you for these suggestions. These references have been removed.</b></p>		
MRO NSRF	Yes	<p>The NSRF agrees with the clarifying changes related to adding the phrase “.....do not have a clear line of sight from the generating station switchyard fence to the point of interconnection with a Transmission Owner’s Facility.....”, however, have the following comment for SDT consideration:</p> <ul style="list-style-type: none"> <li>o The Evidence Retention in FAC-003-3, Part C, Compliance, and Section1.2implies that an entity is required to retain evidence for the time period since the last audit. Since Generator Owners’ audit cycles are six (6) years, and the following paragraph statesthat to show compliance for R1, R2, R3, R5, R6 and R7is three calendar years unless directed by the CEA to retain longer as part of an investigation, this section should be clarified to require six years retention for applicable Generator Owners.</li> </ul>
<p><b>Response: Thank you for your comment. The SDT believes the data retention section is appropriate as written. No change made.</b></p>		
Edison Mission Marketing & Trading	Yes	
Alabama Municipal Electric Authority	Yes	

Organization	Yes or No	Question 1 Comment
American Electric Power	Yes	
Public Service Enterprise Group	Yes	
ACES Power Marketing	Yes	
Essential Power, LLC	Yes	
Ingleside Cogeneration LP	Yes	

END OF REPORT

**A. Introduction**

- 1. Title:**           **Transmission and Generation Protection System Maintenance and Testing**
- 2. Number:**       PRC-005-1.1b
- 3. Purpose:**       To ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested.
- 4. Applicability**
  - 4.1.** Transmission Owner.
  - 4.2.** Generator Owner.
  - 4.3.** Distribution Provider that owns a transmission Protection System.
- 5. Effective Date:**     In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements become effective upon Board of Trustee's adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

**B. Requirements**

- R1.** Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:
  - R1.1.** Maintenance and testing intervals and their basis.
  - R1.2.** Summary of maintenance and testing procedures.
- R2.** Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Entity on request (within 30 calendar days). The documentation of the program implementation shall include:
  - R2.1.** Evidence Protection System devices were maintained and tested within the defined intervals.
  - R2.2.** Date each Protection System device was last tested/maintained.

**C. Measures**

- M1.** Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System that affects the reliability of the BES, shall have an associated Protection System maintenance and testing program as defined in Requirement 1.
- M2.** Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System that affects the reliability of the BES, shall have evidence it provided documentation of its associated Protection System maintenance and testing program and the implementation of its program as defined in Requirement 2.

**D. Compliance**



**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Regional Entity.

**1.2. Compliance Monitoring Period and Reset Time Frame**

One calendar year.

**1.3. Data Retention**

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System, shall retain evidence of the implementation of its Protection System maintenance and testing program for three years.

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

**1.4. Additional Compliance Information**

The Transmission Owner and any Distribution Provider that owns a transmission Protection System and the Generator Owner that owns a generation or generator interconnection Facility Protection System, shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

**2. Violation Severity Levels (no changes)**

**E. Regional Differences**

None identified.

**Version History**

<b>Version</b>	<b>Date</b>	<b>Action</b>	<b>Change Tracking</b>
0	April 1, 2005	Effective Date	New
1	December 1, 2005	<ol style="list-style-type: none"> <li>1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>2. Added “periods” to items where appropriate.</li> <li>3. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> </ol>	01/20/05
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation

**Standard PRC-005-1.1b — Transmission and Generation Protection System Maintenance and Testing**

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1a	February 17, 2011	Adopted by Board of Trustees	
1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC's Order is effective as of September 26, 2011)	
1.1a	February 1, 2012	Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner's responsibility	Revision under Project 2010-07
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC's Order dated March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
1.1b	April 23, 2012	Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.	Revision under Project 2010-07

## Appendix 1

Requirement Number and Text of Requirement
<p><b>R1.</b> Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:</p> <p><b>R1.1.</b> Maintenance and testing intervals and their basis.</p> <p><b>R1.2.</b> Summary of maintenance and testing procedures.</p> <p><b>R2.</b> Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include:</p> <p><b>R2.1</b> Evidence Protection System devices were maintained and tested within the defined intervals.</p> <p><b>R2.2</b> Date each Protection System device was last tested/maintained.</p>
<b>Question:</b>
Is protection for a radially-connected transformer protection system energized from the BES considered a transmission Protection System subject to this standard?
<b>Response:</b>
<p>The request for interpretation of PRC-005-1 Requirements R1 and R2 focuses on the applicability of the term “transmission Protection System.” The NERC Glossary of Terms Used in Reliability Standards contains a definition of “Protection System” but does not contain a definition of transmission Protection System. In these two standards, use of the phrase transmission Protection System indicates that the requirements using this phrase are applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directly from the BES.</p> <p>A Protection System for a radially connected transformer energized from the BES would be considered a transmission Protection System and subject to these standards only if the protection trips an interrupting device that interrupts current supplied directly from the BES and the transformer is a BES element.</p>

## Appendix 2

<b>Requirement Number and Text of Requirement</b>
<p><b>R1.</b> Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:</p> <p><b>R1.1.</b> Maintenance and testing intervals and their basis.</p> <p><b>R1.2.</b> Summary of maintenance and testing procedures.</p>
<p><b>Question:</b></p> <ol style="list-style-type: none"><li>1. Does R1 require a maintenance and testing program for the battery chargers for the “station batteries” that are considered part of the Protection System?</li><li>2. Does R1 require a maintenance and testing program for auxiliary relays and sensing devices? If so, what types of auxiliary relays and sensing devices? (i.e transformer sudden pressure relays)</li><li>3. Does R1 require maintenance and testing of transmission line re-closing relays?</li><li>4. Does R1 require a maintenance and testing program for the DC circuitry that is just the circuitry with relays and devices that control actions on breakers, etc., or does R1 require a program for the entire circuit from the battery charger to the relays to circuit breakers and all associated wiring?</li><li>5. For R1, what are examples of "associated communications systems" that are part of “Protection Systems” that require a maintenance and testing program?</li></ol>
<p><b>Response:</b></p> <ol style="list-style-type: none"><li>1. While battery chargers are vital for ensuring “station batteries” are available to support Protection System functions, they are not identified within the definition of “Protection Systems.” Therefore, PRC-005-1 does not require maintenance and testing of battery chargers.</li><li>2. The existing definition of “Protection System” does not include auxiliary relays; therefore, maintenance and testing of such devices is not explicitly required. Maintenance and testing of such devices is addressed to the degree that an entity’s maintenance and testing program for 3 DC control circuits involves maintenance and testing of imbedded auxiliary relays. Maintenance and testing of devices that respond to quantities other than electrical quantities (for example, sudden pressure relays) are not included within Requirement R1.</li><li>3. No. “Protective Relays” refer to devices that detect and take action for abnormal conditions. Automatic restoration of transmission lines is not a “protective” function.</li><li>4. PRC-005-1 requires that entities 1) address DC control circuitry within their program, 2) have a basis for the way they address this item, and 3) execute the program. PRC-005-1 does not establish specific additional requirements relative to the scope and/or methods included within the program.</li><li>5. “Associated communication systems” refer to communication systems used to convey essential Protection System tripping logic, sometimes referred to as pilot relaying or teleprotection. Examples include the following:<ul style="list-style-type: none"><li>• communications equipment involved in power-line-carrier relaying</li><li>• communications equipment involved in various types of permissive protection system</li></ul></li></ol>

**Standard PRC-005-1.1b — Transmission and Generation Protection System Maintenance and Testing**

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applications

- direct transfer-trip systems
- digital communication systems (which would include the protection system communications functions of standard IEC 618501 as well as various proprietary systems)

A. Introduction

1. **Title:** Transmission and Generation Protection System Maintenance and Testing
2. **Number:** PRC-005-1.1b
3. **Purpose:** To ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested.
4. **Applicability**
  - 4.1. Transmission Owner.
  - 4.2. Generator Owner.
  - 4.3. Distribution Provider that owns a transmission Protection System.

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

~~B. Requirements~~

~~5. **R1-Effective Date:** In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements become effective upon Board of Trustee's adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

B. Requirements

**R1.** Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:

- R1.1.** Maintenance and testing intervals and their basis.
- R1.2.** Summary of maintenance and testing procedures.

**R2.** Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization~~Entity~~ on request (within 30 calendar days). The documentation of the program implementation shall include:

- R2.1.** Evidence Protection System devices were maintained and tested within the defined intervals.
- R2.2.** Date each Protection System device was last tested/maintained.

C. Measures

**M1.** Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System that affects the reliability of the BES, shall have an associated Protection System maintenance and testing program as defined in Requirement 1.

- M2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System that affects the reliability of the BES, shall have evidence it provided documentation of its associated Protection System maintenance and testing program and the implementation of its program as defined in Requirement 2.

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Monitoring Responsibility

Regional ~~Reliability Organization~~Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

#### 1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System, shall retain evidence of the implementation of its Protection System maintenance and testing program for three years.

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

#### 1.4. Additional Compliance Information

The Transmission Owner and any Distribution Provider that owns a transmission Protection System and the Generator Owner that owns a generation or generator interconnection Facility Protection System, shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

### 2. Violation Severity Levels of Non-Compliance(no changes)

~~2.1. Level 1: Documentation of the maintenance and testing program provided was incomplete as required in R1, but records indicate maintenance and testing did occur within the identified intervals for the portions of the program that were documented.~~

~~2.2. Level 2: Documentation of the maintenance and testing program provided was complete as required in R1, but records indicate that maintenance and testing did not occur within the defined intervals.~~

~~2.3. Level 3: Documentation of the maintenance and testing program provided was incomplete, and records indicate implementation of the documented portions of the maintenance and testing program did not occur within the identified intervals.~~

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

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	<ol style="list-style-type: none"> <li>1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>2. Added “periods” to items where appropriate.</li> <li>3. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> </ol>	01/20/05
<del>1</del>	<del>February 7, 2006</del>	<del>Adopted by NERC Board of Trustees</del>	
<del>1a</del>	<del>November 5, 2009</del>	<del>Interpretation of R1, R1.1, and R1.2 adopted by the NERC Board of Trustees</del>	<del>Project 2009-10 Interpretation</del>
1a	February 17, 2011	<u>Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers</u> <del>adopted by the NERC Board of Trustees (adopted and filed as 1a instead of 1b)</del>	Project 2009-17 <u>Interpretation</u>
<u>1a</u>	<u>February 17, 2011</u>	<u>Adopted by Board of Trustees</u>	
1a	September 26, 2011	<del>FERC Order issued approving interpretation regarding applicability of standard to protection of radially connected transformers of R1 and R2</del> (FERC’s Order is effective as of September 26, 2011)	<del>Project 2009-17 Interpretation</del>
<u>1.1a</u>	<u>February 1, 2012</u>	<u>Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility</u>	<u>Revision under Project 2010-07</u>
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC’s Order <del>is effective as of</del> <u>dated</u> March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
<u>1.1b</u>	<u>April 23, 2012</u>	<u>Updated standard version to 1.1b to reflect</u>	<u>Revision under Project</u>



Standard PRC-005-1.1b — Transmission and Generation Protection System Maintenance and Testing

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		<u>FERC approval of PRC-005-1b.</u>	<u>2010-07</u>
<u>1.1b</u>	<u>May 9, 2012</u>	<u>Adopted by Board of Trustees</u>	

## Appendix 1

Requirement Number and Text of Requirement
<p><b>R1.</b> Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:</p> <p><b>R1.1.</b> Maintenance and testing intervals and their basis.</p> <p><b>R1.2.</b> Summary of maintenance and testing procedures.</p> <p><b>R2.</b> Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include:</p> <p><b>R2.1</b> Evidence Protection System devices were maintained and tested within the defined intervals.</p> <p><b>R2.2</b> Date each Protection System device was last tested/maintained.</p>
<b>Question:</b>
Is protection for a radially-connected transformer protection system energized from the BES considered a transmission Protection System subject to this standard?
<b>Response:</b>
<p>The request for interpretation of PRC-005-1 Requirements R1 and R2 focuses on the applicability of the term “transmission Protection System.” The NERC Glossary of Terms Used in Reliability Standards contains a definition of “Protection System” but does not contain a definition of transmission Protection System. In these two standards, use of the phrase transmission Protection System indicates that the requirements using this phrase are applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directly from the BES.</p> <p>A Protection System for a radially connected transformer energized from the BES would be considered a transmission Protection System and subject to these standards only if the protection trips an interrupting device that interrupts current supplied directly from the BES and the transformer is a BES element.</p>



# Implementation Plan for PRC-005-1.1b— Transmission and Generation Protection System Maintenance and Testing

## **Prerequisite Approvals**

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

## **Revision to Sections of Approved Standards and Definitions**

There are no proposed revisions to requirements in other already-approved standards. PRC-005-1b will be retired when PRC-005-1.1b becomes effective.

## **Compliance with Standard**

The proposed changes to Requirement R1 and R2 are clarifying changes. While there was no reliability gap in the previous version of the standard, if applied literally, there was the possibility for the misperception that the Generator Owner was only responsible for analyzing its generator Protection System, exclusive of its generator interconnection Facility Protection System. The minor changes to R1 and R2 make clear that generator interconnection Facilities are also part of Generator Owners' responsibility in the context of this standard.

Because the change is merely a clarifying change, no additional time for compliance is needed.

## **Effective Date**

In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements become effective upon Board of Trustees' adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

# Implementation Plan for PRC-005-1.1a1b Transmission and Generation Protection System Maintenance and Testing

## Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

## Revision to Sections of Approved Standards and Definitions

There are no proposed revisions to requirements in other already approved standards. PRC-005-~~1a-1b~~ will be retired when PRC-005-1.1a1b becomes effective.

## Compliance with Standard

The proposed changes to Requirement R1 and R2 are clarifying changes. While there was no reliability gap in the previous version of the standard, if applied literally, there was the possibility for the misperception that the Generator Owner was only responsible for analyzing its generator Protection System, exclusive of its generator interconnection Facility Protection System. The ~~errata~~ minor changes to R1 and R2 make clear that generator interconnection Facilities are also part of Generator Owners' responsibility in the context of this standard.

Because the change is merely a clarifying change, no additional time for compliance is needed.

## Effective Date

In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements become effective upon Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

# Consideration of Comments

## Generator Requirements at the Transmission Interface Project 2010-07: PRC-005-1.1a

The GOTO Drafting Team thanks all commenters who submitted comments on the first formal posting for PRC-005-1.1a, part of Project 2010-07—Generator Requirements at the Transmission Interface. Overwhelmingly, commenters approved the standard as written, and the team appreciates that support. These standards were posted for a 45-day public comment period from March 2, 2012 through April 16, 2012. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 19 sets of comments, including comments from approximately 65 different people from approximately 38 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

A few commenters did not support the use of the term “generator interconnection Facility” without a formal definition. Based on comments received elsewhere in this project, the SDT has avoided the creation of new NERC glossary terms, and has received significant industry support for that strategy. While it is possible that other language could have been used, the SDT believes the reference “generator interconnection Facility” is clear.

Some commenters are concerned about the changes proposed in PRC-005-1.1a given the fact that PRC-005-2 is also being revised. PRC-005-2 does not have the same issues as PRC-005-1, so no additional changes are needed to that standard to incorporate generator interconnection Facilities, but in case PRC-005-2 does not proceed to NERC’s Board of Trustees, the SDT wants to ensure that the generator interconnection Facility is covered.

Some commenters were concerned about the language in the Data Retention section of the standard. That portion of the standard was modified by NERC staff during the quality review to add boilerplate compliance language recently approved by NERC legal staff. Modifying it further is outside the scope of this SDT.

Some commenters pointed out that PRC-005-1b was approved by FERC on March 14, 2012, replacing PRC-005-1a. As noted in the text box above, going forward, all references to PRC-005-1.1a will be changed to refer to PRC-005-1.1b.

**Note:** PRC-005-1b was approved by FERC on March 14, 2012. Thus, the changes the SDT proposes will be applied to that version of the standard. To reduce confusion, the SDT’s modified standard is still referred to as PRC-005-1.1a below, but all other documents going forward will be appropriately updated to reference PRC-005-1.1b and incorporate the associated interpretation.

Some commenters stated that the addition of “generator interconnection Facility” was unnecessary because that Facility is already considered part of the Generator Owner’s assets. While the SDT believes that Generator Owners do treat the generator interconnection Facility as one of their assets, commenters in previous postings suggested that adding “generator interconnection Facility” could add clarity to the specific language in PRC-004 and PRC-005. It was pointed out to the SDT that language in the requirements of PRC-004 and PRC-005 differed from PRC-001-1, so if the requirements were applied literally, there was the possibility for the misperception that the Generator Owner was only responsible for analyzing its generator Protection Systems, exclusive of its generator interconnection Facility Protection Systems under PRC-004 and PRC-005 (whereas this interpretation wasn’t a risk under PRC-001).

PRC-001-1 used language that had more a more broad application as noted below:

- R1 – “...shall be familiar with the purpose and limitations of protection system schemes applied in its area.”
- R2 – “...shall notify reliability entities of relay or equipment failures as follows...”
- R3 “...shall coordinate new protective systems and changes as follows...”

PRC-004-2a and PRC-005-1b originally used language which could be construed as being more restrictive (as shown below):

- PRC-004-2a@R2 – “The Generator Owner shall analyze its generator Protection System Misoperations...”
- PRC-005-1b@R1 – “...each Generator Owner that owns a generation Protection System...”
- PRC-005-1b@R2 – “...each Generator Owner that owns a generation Protection System...”

The SDT agreed with the comments and modified the standards accordingly.

Other minority comments are addressed alongside their specific comments below.

The SDT considered all stakeholder comments submitted and determined that, save for the update to reference PRC-005-1.1b instead of PRC-005-1.1a, no additional changes are necessary. The standard will be posted for a recirculation ballot.

All comments submitted may be reviewed in their original format on the standard’s project page:

[http://www.nerc.com/filez/standards/Project2010-07\\_GOTO\\_Project.html](http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html)

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission,

you can contact the Vice President of Standards and Training, Herb Schrayshuen, at 404-446-2560 or at [herb.schrayshuen@nerc.net](mailto:herb.schrayshuen@nerc.net). In addition, there is a NERC Reliability Standards Appeals Process.<sup>1</sup>

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<sup>1</sup> The appeals process is in the Reliability Standards Development Procedures: <http://www.nerc.com/standards/newstandardsprocess.html>.



**Index to Questions, Comments, and Responses**

1. Based on stakeholder comment, the SDT inserted the phrase “or generator interconnection Facility” in Requirements R1 and R2 of PRC-005-1.1a. While there was no reliability gap in the previous version of the standard, if the Requirements were applied literally, there was the possibility for the misperception that the Generator Owner was only responsible for analyzing its generator Protection Systems, exclusive of its generator interconnection Facility Protection Systems. The clarifying changes to R1 and R2 make clear that generator interconnection Facilities are also part of Generator Owners’ responsibility in the context of this standard. Do you support the addition of the phrase “or generator interconnection Facility” to accomplish this clarification? ..... 9
2. Do you have any other comments that you have not yet addressed? If yes, please explain. .... 13

**The Industry Segments are:**

- 1 — Transmission Owners
- 2 — RTOs, ISOs
- 3 — Load-serving Entities
- 4 — Transmission-dependent Utilities
- 5 — Electric Generators
- 6 — Electricity Brokers, Aggregators, and Marketers
- 7 — Large Electricity End Users
- 8 — Small Electricity End Users
- 9 — Federal, State, Provincial Regulatory or other Government Entities
- 10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment										
				1	2	3	4	5	6	7	8	9	10	
1.	Group	Jesus Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X					X
<b>Additional Member Additional Organization Region Segment Selection</b>														
1.	Jose Landeros	IID	WECC	1, 3, 4, 5, 6										
2.	Epi Martinez	IID	WECC	1, 3, 4, 5, 6										
2.	Group	Guy Zito	Northeast Power Coordinating Council											
<b>Additional Member Additional Organization Region Segment Selection</b>														
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10										
2.	Greg Campoli	New York Independent System Operator	NPCC	2										
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1										
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1										
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10										

Group/Individual	Commenter	Organization	Registered Ballot Body Segment																	
			1	2	3	4	5	6	7	8	9	10								
6.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5																
7.	Kathleen Goodman	ISO - New England	NPCC	2																
8.	Chantel Haswell	FPL Group, Inc.	NPCC	5																
9.	David Kiguel	Hydro One Networks Inc.	NPCC	1																
10.	Michael R. Lombardi	Northeast Utilities	NPCC	1																
11.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9																
12.	Bruce Metruck	New York Power Authority	NPCC	6																
13.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10																
14.	Robert Pellegrini	The United Illuminating Company	NPCC	1																
15.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1																
16.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5																
17.	Brian Robinson	Utility Services	NPCC	8																
18.	Saurabh Saksena	National Grid	NPCC	1																
19.	Michael Schiavone	National Grid	NPCC	1																
20.	Wayne Sipperly	New York Power Authority	NPCC	5																
21.	Tina Teng	Independent Electricity System Operator	NPCC	2																
22.	Donald Weaver	New Brunswick System Operator	NPCC	2																
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1																
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.		3																
3.	Group	Jonathan Hayes	Southwest Power Pool Standards Development Team		X	X	X		X	X										
	<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>																
1.	Jonathan Hayes	Southwest Power Pool	SPP	NA																
2.	Robert Rhodes	Southwest Power Pool	SPP	NA																
3.	Dan Lusk	Xcel Energy	SPP	1, 3, 5, 6																
4.	Julie Lux	Westar	SPP	1, 3, 5, 6																
5.	Mahmood Safi	OPPD	MRO	1, 3, 5																
6.	Roy Boyer	Xcel Energy	SPP	1, 3, 5, 6																
7.	Mitchell Williams	Western Farmers	SPP	1, 3, 5																
8.	John Pasierb	East Texas	NA - Not Applicable	NA																
9.	David Kral	Xcel Energy	SPP	1, 3, 5, 6																
10.	Tom Hesterman	Westar	SPP	1, 3, 5, 6																

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
11.	Tiffani Lake	Westar	SPP	6, 1, 3, 5									
12.	Don Taylor	Westar	SPP	1, 3, 5, 6									
4.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				
<b>Additional Member Additional Organization Region Segment Selection</b>													
1.	Dean	Bender	WECC	1									
5.	Group	Mike Garton	Dominion- NERC Compliance Policy	X		X		X	X				
<b>Additional Member Additional Organization Region Segment Selection</b>													
1.	Connie Lowe	NERC Compliance Policy	RFC	6									
2.	Louis Slade	NERC Compliance Policy	SERC	5									
3.	Michael Crowley	Electric Transmission	SERC	1, 3									
4.	Sean Iseminger	Fossil & Hydro	SERC	6									
5.	Chip Humphrey	Fossil & Hydro	NPCC	6									
6.	Jeff Bailey	Nuclear	MRO	6									
6.	Group	Jean Nitz	ACES Power Marketing Standards Collaborators	X		X	X	X	X				
<b>Additional Member Additional Organization Region Segment Selection</b>													
1.	Mohan Sachdeva	Buckeye Power, Inc	RFC	3, 4									
2.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5									
3.	Clem Cassmeyer	Western Farmers Electric Cooperative	SPP	1, 5									
7.	Individual	Keira Kazmerski	Xcel Energy	X		X		X	X				
8.	Individual	Dan Roethemeyer	Dynegy Inc.					X					
9.	Individual	John Bee	Exelon	X		X		X	X				
10.	Individual	Art Salander	HindlePower, Inc										
11.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
12.	Individual	Martin Kaufman	ExxonMobil Research and Engineering	X				X					
13.	Individual	Michelle R D'Antuono	Ingleside Cogeneration LP					X					
14.	Individual	Dale Fredrickson	We Energies			X	X	X					
15.	Individual	Michael Falvo	Independent Electricity System Operator		X								
16.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment										
				1	2	3	4	5	6	7	8	9	10	
17.	Individual	Thad Ness	American Electric Power	X		X		X	X					
18.	Individual	Darryl Curtis	Oncor Electric Delivery Company	X										
19.	Individual	Will Smith	MRO NSRF											

1. **Based on stakeholder comment, the SDT inserted the phrase “or generator interconnection Facility” in Requirements R1 and R2 of PRC-005-1.1a. While there was no reliability gap in the previous version of the standard, if the Requirements were applied literally, there was the possibility for the misperception that the Generator Owner was only responsible for analyzing its generator Protection Systems, exclusive of its generator interconnection Facility Protection Systems. The clarifying changes to R1 and R2 make clear that generator interconnection Facilities are also part of Generator Owners’ responsibility in the context of this standard. Do you support the addition of the phrase “or generator interconnection Facility” to accomplish this clarification?**

#### **Summary Consideration:**

The SDT thanks all commenters for their feedback on the proposed changes to PRC-005-1.1a. Over 90% of commenters approved the standard as written, and the team appreciates that support.

A few commenters did not support the use of the term “generator interconnection Facility” without a formal definition. Based on comments received elsewhere in this project, the SDT has avoided the creation of new NERC glossary terms, and has received significant industry support for that strategy. While it is possible that other language could have been used, the SDT believes “generator interconnection Facility” is clear, and no changes were made.

One commenter stated that the addition of “generator interconnection Facility” was unnecessary and complicates the ongoing development of PRC-005-2. The SDT believes that the clarifying language is necessary, and points out that if PRC-005-1.1a proceeds to recirculation ballot next as planned, it will actually be slightly ahead of the PRC-005-2 work, because the drafting team working on PRC-005-2 is still reviewing stakeholder comments from a successive ballot that ended March 28, 2012.

One commenter stated that the addition of “generator interconnection Facility” was unnecessary because that Facility is already considered part of the Generator Owner’s assets. While the SDT believes that Generator Owners do treat the generator interconnection Facility as one of their assets, some commenters in previous postings suggested that adding “generator interconnection Facility” could add clarity to the specific language in PRC-004 and PRC-005. The SDT agreed and incorporated that language prior to the last posting.

The SDT considered all of these comments and determined that, save for the update to reference PRC-005-1.1b instead of PRC-005-1.1a, no additional changes are necessary.

Organization	Yes or No	Question 1 Comment
Southwest Power Pool Standards Development Team	No	We would advise the Drafting team to take a look at the FERC OATT to reconcile the term “generator interconnection facility “with Tariff term for the LGIA. This should clarify the point of delineation and there should be no misconception of the language as written.
<p><b>Response:</b> Thank you for the comment. As recommended by stakeholders throughout this project, the SDT has avoided creation of new terms. No change made.</p>		
Xcel Energy	No	Xcel Energy does not believe that trying to implement a revision of PRC-005-1 at this point improves the reliability of the grid. There are better means of clarifying the perceived “misperceptions” than drafting a standard revision. This is particularly the case when PRC-005-2 is further along in the process and is also posted for industry comment and ballot. The effort of the GOTO SDT is counterproductive.
<p><b>Response:</b> Thank you for your comment. The SDT revised the standard based upon comments it received suggesting that it do so. We do agree that there may have been alternative means to address the issue, such as a request for interpretation or CAN, but given this was in the scope of the SAR, the SDT modified the standard to add the clarity recommended. If PRC-005-1.1a proceeds to recirculation ballot next as planned, it will actually be slightly ahead of the PRC-005-2 work, because the drafting team working on PRC-005-2 is still reviewing stakeholder comments from a successive ballot that ended March 28, 2012.</p>		
ExxonMobil Research and Engineering	No	The bulk electric system is contiguous. Therefore, any facility owned by the Generator Owner that is used to connect the Generator Owner’s generation facilities to the bulk electric system is already considered a bulk electric system asset and part of the Generator Owner’s generation facilities. As stated by in the question above, the addition of the term “or generator interconnection Facility” does not resolve a reliability gap or add any substance to the requirement
<p><b>Response:</b> Thank you for your comment. The SDT added the language to add clarity. As we cited above, while there was no reliability gap in the previous version of the standard, if the Requirements were applied literally, there was the possibility for the</p>		

Organization	Yes or No	Question 1 Comment
<p>misperception that the Generator Owner was only responsible for analyzing its generator Protection Systems, exclusive of its generator interconnection Facility Protection Systems. We believe that the clarifying change is useful.</p>		
<p>Kansas City Power &amp; Light (<b>Note: Comment was manually added</b>)</p>	<p>No</p>	<p>The phrase “generator interconnection” facility lacks definition making it difficult to comment on the proposed change. It is important for the standards and requirements to clearly delineate, define, or identify the facilities or operating condition subject to application of the standards and requirements.</p>
<p><b>Response:</b> Thank you for your comment. As recommended by stakeholders throughout this project, the SDT has avoided creation of new terms. No change made.</p>		
<p>Ingleside Cogeneration LP</p>	<p>Yes</p>	<p>Since PRC-005-1 already requires the Generation Owner to maintain and test all their BES Protection System components, it seems to Ingleside Cogeneration LP that the need to specify those which may trip the interconnection facility as redundant. However, we do not believe that the Standard Development Team’s modifications materially change the intent of the Standard - nor can they lead an audit team to assign a double violation for a single incidence of non-compliance.</p>
<p><b>Response:</b> Thank you for your comment. The SDT added the language to add clarity. As we cited above, while there was no reliability gap in the previous version of the standard, if the Requirements were applied literally, there was the possibility for the misperception that the Generator Owner was only responsible for analyzing its generator Protection Systems, exclusive of its generator interconnection Facility Protection Systems. We believe that the clarifying change is useful.</p>		
<p>Imperial Irrigation District (IID)</p>	<p>Yes</p>	
<p>Northeast Power Coordinating Council</p>	<p>Yes</p>	
<p>Imperial Irrigation District (IID)</p>	<p>Yes</p>	



Organization	Yes or No	Question 1 Comment
Bonneville Power Administration	Yes	
Dominion- NERC Compliance Policy	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Dynegy Inc.	Yes	
HindlePower, Inc	Yes	
Public Service Enterprise Group	Yes	
We Energies	Yes	
Independent Electricity System Operator	Yes	
Manitoba Hydro	Yes	
American Electric Power	Yes	
Oncor Electric Delivery Company	Yes	

## 2. Do you have any other comments that you have not yet addressed? If yes, please explain.

### Summary Consideration:

The SDT thanks all commenters for their feedback on the proposed changes to PRC-005-1.1a. Overwhelmingly, commenters approved of the standard as written, and the team appreciates that support.

Some commenters are concerned about the changes proposed in PRC-005-1.1a given the fact that PRC-005-2 is also being revised. PRC-005-2 does not have the same issues as PRC-005-1, so no additional changes are needed to that standard to incorporate generator interconnection Facilities, but in case PRC-005-2 does not proceed to NERC's Board of Trustees, the SDT wants to ensure that the generator interconnection Facility is covered.

Some commenters were concerned about the language in the Data Retention section of the standard. That portion of the standard was modified by NERC staff during the quality review to add boilerplate compliance language recently approved by NERC legal staff. Modifying it further is outside the scope of this SDT.

Some commenters pointed out that PRC-005-1b was approved by FERC on March 14, 2012, replacing PRC-005-1a. Going forward, all references to PRC-005-1.1a will be changed to refer to PRC-005-1.1b.

Some commenters did not support the use of the term "generator interconnection Facility" without a formal definition. Based on comments received elsewhere in this project, the SDT has avoided the creation of new NERC glossary terms, and has received significant industry support for that strategy. While it is possible that other language could have been used, the SDT believes "generator interconnection Facility" is clear, and no changes were made.

One commenter was concerned that the addressing of a literal "reliability gap" should not be considered an errata change. The SDT maintains that there is no actual reliability gap in the current standard language – just the possible perception of one. The SDT and most stakeholders still believe that the clarifying change is a useful one, but it is appropriate to classify as a minor change because it does not change the scope or intent of the associated standard. Still, the SDT agrees that the errata label is confusing, as errata changes do not require a ballot. The SDT will no longer refer to its changes as errata.

One commenter was concerned that the standard as written does not allow for alternative testing programs in cases where testing programs do not follow the ownership of the equipment. The SDT points out that an entity can enter into an agreement (including a Coordinated Functional Registration) whereby another entity is assigned responsibility for compliance with one or more requirements of one or more reliability standards without the standard itself being so modified. The SDT therefore does not agree that this standard should be explicitly modified to allow what the commenter suggests.

One commenter was concerned about the statement that “no changes” were made to the VSLs. Because the SDT has not proposed changes that affect the scope or intent of the current standard, no changes to the VSLs were necessary. The same VSLs that have been approved by FERC (which can be found in the VSL matrix posted on NERC’s website: <http://www.nerc.com/page.php?cid=2|20|288>) will remain in effect.

One commenter stated that the addition of “generator interconnection Facility” was unnecessary because that Facility is already considered part of the Generator Owner’s assets. While the SDT believes that Generator Owners do treat the generator interconnection Facility as one of their assets, some commenters in previous postings suggested that adding “generator interconnection Facility” could add clarity to the specific language in PRC-004 and PRC-005. The SDT agreed and modified the standards accordingly.

One commenter continues to find the changes proposed under Project 2010-07 to be unnecessary. As it has in previously consideration of comment reports, the SDT points out that it must act within the scope of the SAR for this project. As mandated by its SAR, the SDT has addressed standards for which there is a reliability gap or possible perception of a gap when it comes to the generator interconnection Facility, as justified in great depth in its [Technical Justification document](#).

One commenter encouraged the SDT to update the Effective Dates and Implementation Dates language to incorporate the latest NERC legal boilerplate language. That change has been made.

The SDT considered all of these comments and determined that, save for the update to reference PRC-005-1.1b instead of PRC-005-1.1a, no additional changes are necessary.

Organization	Yes or No	Question 2 Comment
Baltimore Gas & Electric Company	Abstain	Please refer to comments submitted by Exelon.
Southwest Power Pool Standards Development Team	Yes	This effort seems to be redundant due to the work going on with PRC-005-2. We do not understand why this change is being made and it wasn’t made very clear in the red line changes or in this comment form background.
<p><b>Response:</b> Thank you for your comment. The Project 2007-17 Protection System Maintenance and Testing SDT is working on comprehensive changes to PRC-005, as described in detail in the SAR posted on that projects webpage, while the Project 2010-07</p>		

Organization	Yes or No	Question 2 Comment
<p>Generator Requirements at the Transmission Interface SDT is focused on making surgical revisions to standards where there might be a reliability gap related to generator-owned Transmission Facilities. The current draft of PRC-005-2 does not have the same issues as PRC-005-1 with respect to generator-owned Facilities, so no additional changes are needed to that standard to incorporate generator interconnection Facilities, but in case PRC-005-2 does not proceed to NERC’s BOT, the Project 2010-07 SDT wants to ensure that the generator interconnection Facility is covered.</p>		
<p>Bonneville Power Administration</p>	<p>Yes</p>	<p>Regarding Section 1.3 Data Retention, BPA believes that it would be difficult for an entity to provide “other evidence” to demonstrate compliance when the data retention period is shorter than the time since the last audit. BPA requests the drafting team to offer guidance as to what "other evidence" could be provided other than what is already described in the measures. BPA believes that suggesting there is some “other evidence” without providing a description leaves the TO’s and GO’s without clear direction on how to comply with the standard. BPA suggests the data retention period should be three years or since the time the last audit occurred, whichever is longer for each TO and GO to retain evidence. Should the drafting team revise the Data Retention language to reflect BPA’s concerns, BPA would vote in favor of PRC-005-1.1a.</p>
<p><b>Response:</b> Thank you for your comment. This section was revised by NERC staff to add boilerplate compliance language recently approved by NERC legal staff. Thus, it is outside the scope of the SDT and no change was made.</p>		
<p>ACES Power Marketing Standards Collaborators</p>	<p>Yes</p>	<p>The Implementation Plan for PRC-005-1.1a should be updated to reflect the retirement of currently effective PRC-005-1b instead of PRC-005-1a. PRC-005-1b became effective on March 14, 2012 replacing PRC-005-1a.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees with the comment and has made the suggested changes.</p>		
<p>Exelon</p>	<p>Yes</p>	<p>The standard language should be clarified to allow for alternative testing programs, agreed upon by both TO and GO, in cases where testing programs do not follow ownership of the equipment for all Component Types so long as all of the protection for the generator interconnection facility is covered.</p>

Organization	Yes or No	Question 2 Comment
<p><b>Response:</b> Thank you for your comment. An entity can enter into an agreement (including a Coordinated Functional Registratyon) whereby another entity is assigned responsibility for compliance with one or more requirements of one or more reliability standards without the standard itself being so modified. The SDT therefore does not agree that this standard should be explicitly modified to allow this. No change made.</p>		
ExxonMobil Research and Engineering	Yes	<p>The SDT has utilized two terms in this round of the drafting process whose definitions are subject to interpretation. The terms ‘generating station switchyard’ and ‘generator interconnection Facility’ need to be defined to prevent inconsistent enforcement or need for the development of a Compliance Application Notice. As referenced in our comments to FAC-003-X/3, when you try to apply the term ‘generating station switchyard’ to an industrial complex that contains multiple substations between the GSU and utility interconnection facility (another substation) in order to measure the generator lead line for the 1 mile quota, there are several candidates that appear to fit the criteria.</p>
<p><b>Response:</b> Thank you for your comment. As recommended by stakeholders throughout this project, the SDT has avoided creation of new NERC glossary terms. While the SDT concedes there may be other language that could be used, the language posted has wide industry support, therefore no change will be made.</p>		
American Electric Power	Yes	<p>While we support changing the standard requirements as proposed, AEP offers the following comments and suggestions. While the implementation plans states that “there was no reliability gap in the previous version of the standard”, the previous version of the standard, if applied literally, does indeed contain a reliability gap in that it does not require Generation Owners that own a transmission Protection System to have a Protection System maintenance and testing program. It is AEP’s understanding that referring to the proposed revision as “PRC-005-1.1a” implies errata from PRC-005-1a, and the announcement refers to “very limited revisions”. If there is indeed a gap of responsibility in this standard, any changes to remediate such a gap would not be errata, regardless of the amount of proposed changes in content. As such, we recommend that the drafting team use a full revision naming</p>

Organization	Yes or No	Question 2 Comment
		<p>convention for these proposed changes, i.e. PRC-005-2. In addition, making these changes immediately effective would allow no opportunity for an entity to take the proper steps to become compliant. We believe the revision should include an implementation plan that allows industry adequate time to analyze their system and complete any additionally required maintenance and testing activities.</p>
<p><b>Response:</b> Thank you for your comment. The SDT added the language to add clarity. As we cited above, while there was no reliability gap in the previous version of the standard, if the Requirements were applied literally, there was the possibility for the misperception that the Generator Owner was only responsible for analyzing its generator Protection Systems, exclusive of its generator interconnection Facility Protection Systems. We believe that the clarifying change is a useful one, but it is appropriate to classify as a minor change because it does not change the scope or intent of the associated standard. Regarding the naming convention, the SDT was advised that the errata naming convention would be acceptable to avoid confusion with the more complete set of revisions to PRC-005 that are underway in Project 2007-17. The SDT had previously used the word “errata” to describe its changes, but agrees that the errata label is confusing, as errata changes do not require a ballot. The SDT will no longer refer to its changes as errata. No change made.</p>		
<p>Southern Illinois Power Coop., Brazos Electric Power Cooperative, Inc.</p>	<p>Affirmative</p>	<p>The Implementation Plan for PRC-005-1.1a should be updated to reflect the retirement of currently effective PRC-005-1b instead of PRC-005-1a. PRC-005-1b became effective on March 14, 2012 replacing PRC-005-1a.</p>
<p><b>Response:</b> Thank you for your comment. The SDT agrees with the comment and has made the suggested changes.</p>		
<p>Pacific Gas and Electric Company</p>	<p>Affirmative</p>	<p>The data retention period identified in D1.3 cannot be shorter than the time between audits or the prior maintenance and testing interval</p>
<p><b>Response:</b> Thank you for your comment. This section was revised by NERC staff to add boilerplate compliance language recently approved by NERC legal staff. Thus, it is outside the scope of the SDT and no change was made.</p>		
<p>AEP Service Corp., AEP and AEP Marketing, American Electric Power</p>	<p>Affirmative</p>	<p>Comments are being submitted via electronic form by Thad Ness on behalf of American Electric Power</p>

Organization	Yes or No	Question 2 Comment
Great River Energy	Affirmative	Great River Energy agrees with the comments of the MRO NSRF.
Dairyland Power Coop.	Affirmative	Please see comments submitted by MRO NSRF.
Muscatine Power & Water	Affirmative	Please see comments submitted by the MRO NERC Standards Review Forum
Madison Gas and Electric Co.	Affirmative	Please see MRO NSRF comments.
Omaha Public Power District	Affirmative	Please see MRO NSRF Comments.
Brazos Electric Power Cooperative, Inc.	Affirmative	See ACES Power Marketing comments.
Occidental Chemical	Affirmative	See comments submitted by Ingleside Cogeneration LP
Central Electric Power Cooperative	Affirmative	See Matt Pacobit's comments from AECl
Southern Company Services, Inc.	Affirmative	None
Alabama Power Company	Affirmative	None
Georgia Power Company	Affirmative	None
Gulf Power Company	Affirmative	None
Mississippi Power	Affirmative	None
Southern Company Generation and Energy	Affirmative	None

Organization	Yes or No	Question 2 Comment
Marketing		
Beaches Energy Services	Affirmative	(No Comments.)
Independent Electricity System Operator		The proposed implementation plan conflicts with Ontario regulatory practice respecting the effective date of the standard. It is suggested that this conflict be removed by appending to the implementation plan wording, after “applicable regulatory approval” in the Effective Dates Section A5 of the draft standard and P. 1 of the Implementation Plan, to the following effect:”, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.”
<p><b>Response:</b> Thank you for your comment. The language you cite has been approved by NERC legal and has been updated in the Effective Dates section and in the Implementation Plan.</p>		
Sunflower Electric Power Corporation	Negative	A new term is introduced that is not a NERC defined term, the term is generator interconnection Facility. The term was inserted without comment and clearly is intended to include something that is not covered by the Standard. This new term should be removed or defined in Glossary of Terms so entities may understand just what is covered by this new term. The Implementation Plan for PRC-005-1.1a should be updated to reflect the retirement of currently effective PRC-005-1b instead of PRC-005-1a. PRC-005-1b became effective on March 14, 2012 replacing PRC-005-1a.
<p><b>Response:</b> Thank you for your comment. As recommended by stakeholders throughout this project, the SDT has avoided creation of new NERC glossary terms. The SDT purposefully did not create a new term (note that only Facility is capitalized, while generator and interconnection are not). No change made.</p>		
Seminole Electric Cooperative, Inc.	Negative	a) Section D.2 Violation Severity Levels (no changes) - The standard should stand on its own, therefore, just stating that the VSLs have "(no changes)" is incomplete and will lead to confusion. Please provide definition and clarity to this section.
<p><b>Response:</b> Thank you for your comment. The SDT has not proposed changes that affect the scope or intent of the current standard,</p>		



Organization	Yes or No	Question 2 Comment
<p>and because of that, no changes to the VSLs are necessary. The same VSLs that have been approved by FERC (which can be found in the VSL matrix posted on NERC's website: <a href="http://www.nerc.com/page.php?cid=2 20 288">http://www.nerc.com/page.php?cid=2 20 288</a>) will remain in effect. No change made.</p>		
Austin Energy, City of Austin dba Austin Energy	Negative	<p>Adding the words "generator interconnection" to the Facility description does not add clarity to the Standard. PRC-005-1 is clear as written, indicating the actual owner of a device supporting the BES is responsible for performing the actions necessary to comply with PRC-005. The term "generator interconnection" is not defined and introduces confusion, making responsibility for the application of the Requirements less clear.</p>
<p><b>Response:</b> Thank you for your comment. The SDT added the language to add clarity. As we cited above, while there was no reliability gap in the previous version of the standard, if the Requirements were applied literally, there was the possibility for the misperception that the Generator Owner was only responsible for analyzing its generator Protection Systems, exclusive of its generator interconnection Facility Protection Systems. We believe that the clarifying change is useful. No change made.</p>		
Kansas City Power & Light Co.	Negative	Concerns have been expressed in the Standard comment forms provided by NERC.
Tucson Electric Power Co.	Negative	<p>It would be difficult for an entity to provide "other evidence" to demonstrate compliance when the data retention period is shorter than the time since the last audit. Suggest that the data retention period language should be modified to "three years or since the time the last audit occurred, whichever is longer"</p>
<p><b>Response:</b> Thank you for your comment. This section was revised by NERC staff to add boilerplate compliance language recently approved by NERC legal staff. Thus, it is outside the scope of the SDT and no change was made.</p>		
Bonneville Power Administration	Negative	Please refer to BPA's comments submitted separately.
Manitoba Hydro	Negative	Please see comments submitted by Joe Petaski (Manitoba Hydro)
Xcel Energy, Inc.	Negative	Xcel Energy sees this project as counter-productive to the efforts of the Protection

Organization	Yes or No	Question 2 Comment
		System Maintenance and Testing Standard Drafting Team that currently has PRC-005-2 posted for comment and successive ballot.
<p><b>Response:</b> Thank you for your comment. PRC-005-2 does not have the same issues as PRC-005-1, so no additional changes are needed to that standard to incorporate generator interconnection Facilities, but in case PRC-005-2 does not proceed to NERC’s BOT, we want to ensure that the generator interconnection Facility is covered.</p>		
City and County of San Francisco	Negative	This revision should be used as an opportunity to clean up language relating to the data retention period for PRC-005. The following language has been suggested and appears consistent with the actual data retention period needed for all functional registrations encompassed by this Standard: "three years or since the time the last audit occurred, whichever is longer"
<p><b>Response:</b> Thank you for your comment. This section was revised by NERC staff to add boilerplate compliance language recently approved by NERC legal staff. Other changes are outside the scope of the SDT.</p>		
HindlePower, Inc	No	I beleive that the requirments as shown in 1-4a - c need to be better clarified as to the actual tasks required. There seems to be no real distinction between Verification and inspection. There is no clear reporting structure and the requirment to substitute Ohmic readings vs. discharge test is not basede on any industry reliable standards. since there is much debate in the industry as to the validity if Ohmic testing and it has not been accepted by the IEEE as an acceptbale practice I would rather see terms in line with either IEEE standard or manufacvturer's recommendations.
<p><b>Response:</b> Thank you for your comment. The SDT believes these comments may have been intended for the Project 2007-17 drafting team which is making comprehensive revisions to PRC-005-2. The comment will be forwarded to that team by NERC staff.</p>		
Manitoba Hydro	No	Manitoba Hydro does not support the changes being proposed in Project2010-07 in general. If a Generator Owner is required to register as a TO, all theRequirements applicable to a TO should apply. There is no need to changespecific Reliability

Organization	Yes or No	Question 2 Comment
		<p>Standards to allow the Generator Owner to perform only selected TO functions. For additional information, please see Manitoba Hydro's comments submitted in the comment period ending November 18, 2011. Manitoba Hydro does not believe that the SDT fully addressed our concerns in their responses to our comments in that commenting period.</p>
<p><b>Response:</b> Thank you for your comment. The SDT must act within the scope of the SAR for this project. The comments appear to indicate that the entity disagrees with the SAR although they cite the Technical Justification document. The Technical Justification document is meant to be used to show how the SDT arrived at its decisions to revise only 4 reliability standards as opposed to all that were originally included in the Ad Hoc report, or those in the cited FERC orders.</p>		
<p>MRO NSRF</p>		<p><i>Section D, Article 1.3 Data Retention</i> states that the entities retain evidence for the entire audit period since the last audit. Furthermore, in the 2<sup>nd</sup> paragraph of Article 1.3, it states that an entity “shall retain evidence of the implementation of its Protection System maintenance and testing program for three years.”</p> <p>If an entity is to prove compliance related to R2.1 and R2.2 of PRC-005-1.1a, the NSRF recommends that Evidence Retention be revised to state “the two most recent performance of each distinct maintenance activity for the Protection System Components, or all performances of each distinct maintenance activity for the Protection System Component since the previous scheduled audit date, whichever is longer.” This agrees with the current draft in progress for PRC-005-2 Section D, Compliance, Article 1.3, paragraph 4.</p> <p>The NSRF is also concerned with those testing intervals, such as 12 years, which would dictate a Registered Entity maintain 24 years of records, which is unreasonable. This should be revised to have documentation for <u>the most current</u> one testing interval, if after 06/18/07.</p> <p>The NSRF believes that “the term “generation” in R1 and R2 should be changed to “generator”. If changed, both Measures will need to be updated as well.</p>

Organization	Yes or No	Question 2 Comment
<p><b>Response:</b> Thank you for your comment. The Data Retention section was revised by NERC staff to add boilerplate compliance language approved elsewhere. Thus, it is outside the scope of the SDT and no change was made.</p> <p>In R1 and R2, the reference to “generation” was in the original standard, referring to a generation Protection System. While “generator” may work better here, it is not within the scope of the 2010-07 SDT to change language outside the surgical insertion of “generator interconnection Facility.”</p>		
Oncor Electric Delivery Company	No	
Imperial Irrigation District (IID)	No	
Northeast Power Coordinating Council	No	
Imperial Irrigation District (IID)	No	
Dominion- NERC Compliance Policy	No	
Xcel Energy	No	
Dynergy Inc.	No	
Public Service Enterprise Group	No	
Ingleside Cogeneration LP	No	

Organization	Yes or No	Question 2 Comment
We Energies	No	

END OF REPORT

# Technical Justification Resource Document

## Project 2010-07 Generator Requirements at the Transmission Interface

### Background

As part of its work on Project 2010-07—Generator Requirements at the Transmission Interface, the standard drafting team (SDT) reviewed 34 reliability standards and 102 requirements to determine what changes are necessary to close a reliability gap with respect to what is commonly known as the generator interconnection Facility. Many of these standards and requirements had been addressed in the [Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface](#) (Ad Hoc Report) and additional standards were reviewed as a result of informal discussions with NERC and FERC staffs.

The SDT's technical justification document has not changed substantively since it was posted in December 2011, but the document below has been updated to reflect the posted changes to FAC-003-3 and FAC-003-X.

The basis for standard modifications recommended by the Ad Hoc Group for Generator Requirements at the Transmission Interface (Ad Hoc Group) was a few fundamental clarifications to the definitions of Generator Owner, Generator Operator, and Transmission, along with the creation of new definitions: one for Generator Interconnection Facility and one for Generator Interconnection Operational Interface. The Ad Hoc Group proposed the addition of these two new definitions to 26 standards encompassing 29 requirements (new and old), along with some modifications to FAC-003 to make it applicable to Generator Owners under certain circumstances.

Since the publication of the Ad Hoc Report, various entities have challenged these modifications and the recommended creation of the new definitions. The SDT has developed a more focused approach than that of the Ad Hoc Group: to propose recommendations whereby sole-use interconnection Facilities (at or above 100 kV) that are owned and operated by generating entities will be included in a small set of standards and requirements previously only applicable to Transmission Owners. The SDT agrees completely with the Ad Hoc Group's conclusion that Generator Owners and Operators of these sole-use generator tie-line Facilities (at voltages equal to or greater than 100 kV) should not be registered as Transmission Owners and Transmission Operators in order to maintain reliability on the Bulk Electric System (BES).

The SDT's justification for this strategy is rooted in the very title of its standards project: "Generator Requirements at the Transmission Interface." That is, the goal and scope of the project has always been to determine the responsibilities of those Generator Owners and Generator Operators that own or operate an interconnection Facility (in some cases labeled a "transmission Facility") between the generator and the interface with the portion of the BES where Transmission Owners and Transmission

Operators take over ownership and operating responsibility. These kinds of Generator Owners and Generator Operators do not own or operate Facilities that are part of the interconnected system; rather, they own and operate sole-use Facilities that are connected to the boundary of the interconnected system; and as such have a limited role in providing reliability compared to those that operate in a networked fashion beyond the point of interconnection.

While some argue that these interconnecting portions of a Generator Owner's Facilities could be defined as Transmission; and, thus, require the Generator Owner and Generator Operator for the Facility to be classified and registered as a Transmission Owner and Transmission Operator, the SDT does not believe this is necessary to provide an appropriate level of reliability for the BES. Just as important, such classification and registration could actually cause a reduction in reliability. Generator Owners and Generator Operators do not need, and in some cases may be prohibited from having, a wide-area view and responsibility for the integrated transmission system. Requiring Generator Owners and Generator Operators to have such responsibilities would require significant training, require substantially more data and modeling responsibilities, and detract from the entities' primary functions: to own and operate their generation equipment – including any Facilities owned and operated at voltages of 100 kV or greater that connect to the interconnected system – in a reliable manner.

Additionally, the SDT believes that the industry is much more aware today of the need to include *all* elements (owned and operated at 100 kV or higher) of a generator Facility in the procedures and compliance program of the registered entity that owns or has operational responsibility of those elements. Industry awareness was raised substantially at the time the [October 17, 2010 Facility Ratings Recommendation to Industry](#) was issued (which included Generator Owners and specifically addressed interconnection Facilities in [the Q&A document](#) with the statement that the alert applied to generator interconnection tie lines that are radial only and do not serve load “if the generator is considered part of the bulk electric system”). While this applies to a specific NERC recommendation, the SDT considers this compelling evidence that the paradigm for thinking about generator interconnection Facilities is shifting.

All of this has led the SDT to its current conclusions to modify FAC-001, FAC-003, and PRC-004; and later, PRC-005. The SDT does not believe any further modifications to standards are necessary to maintain an appropriate level of reliability based on the revised assumption that while generator Facilities (at 100 kV and above) will be considered by some to be transmission, Generator Owners and Generator Operators should not be registered as Transmission Owners and Transmission Operators simply as a result of the ownership and operation of such Facilities. Because the majority of commenters support the SDT's current recommendation to not adopt new terms, the SDT has elected to focus on its standard changes and not, at this time, propose revisions to existing, or creation of new glossary terms.

Below, the SDT discusses the changes it has proposed for FAC-001, FAC-003, and PRC-004 and the changes it plans to propose for PRC-005, and then provides justification for not modifying any of the additional standards and requirements it has reviewed.

## **Review of SDT's Proposed Standard Changes**

### ***FAC-001-1—Facility Connection Requirements***

While some stakeholders have questioned the modifications in the proposed FAC-001-1, the SDT remains convinced that there is the potential for a reliability gap if this standard is not modified so that it applies to a Generator Owner *if and when it executes an Agreement* to evaluate the reliability impact of interconnecting a third party Facility to its existing generation interconnection Facility. The intent of this modified language is to start the compliance clock when the Generator Owner executes an Agreement to perform the reliability assessment required in FAC-002-1. This step is expected to occur if a Generator Owner is compelled by a regulatory body to allow such interconnection. Assuming that a regulatory body would require a Generator Owner to evaluate such an interconnection request, the SDT expects the Generator Owner and the third party to execute some form of an Agreement. The SDT intentionally excluded a specific reference to the form of Agreement (such as a feasibility study) in deference to stakeholder suggestions to avoid comingling of commercial and reliability issues in reliability standards.

The SDT acknowledges that the scenario described in the proposed FAC-001-1 may be rare, but in the past (for instance, FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13) Generator Owners have received or have been directed to execute interconnection requests for their Facilities, and the SDT thinks it is important to clarify the responsibilities related to such a request in NERC's Reliability Standards. And while the SDT acknowledges that such regulatory action might also result in the Generator Owner being registered for other functions, such as Transmission Owner, Transmission Planner, and/or Transmission Service Provider, it decided the proposed revision provides appropriate reliability coverage until any additional registration is required and does not impact any Generator Owner that never executes an Agreement as described in the standard.

### ***FAC-003-X and FAC-003-3—Vegetation Management***

The SDT and most stakeholders agree with the Ad Hoc Group recommendation that FAC-003 be applicable to Generator Owners that own a generation interconnection Facility if that Facility contains overhead conductors. The Ad Hoc Group originally excluded such a Facility from this requirement if its length is less than two spans (generally one half mile from the generator property line). The SDT agrees with that intended exclusion in principle; as it discusses in the document titled "[Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface](#)," the SDT recognizes that in many cases generation Facilities are (1) staffed and the overhead portion is within line of sight, or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale for exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit.



Thus, the SDT has maintained this exception language, but has modified it based on stakeholder input; such that it excludes Facilities shorter than one mile which have a clear line of sight from the fenced area of the generating switchyard to the point of interconnection. Specifically, to clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight. 4.3.1 of FAC-003-X now reads:

Generator Owner that owns an applicable qualified Facility, where a qualified Facility is an overhead transmission line(s) that (1) extends greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility, or (2) does not have a clear line of sight from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and is operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.

4.3.1 of FAC-003-3 now reads:

Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility, or (2) do not have a clear line of sight from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and are: Operated at 200kV or higher; or operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

Both references to clear line of sight include a footnote stating: "'Clear line of sight' means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day."

The SDT took into consideration all comments submitted in both formal comment periods, and believes that this exemption now adequately addresses the reliability impact for a majority of the Facilities, while balancing the efforts necessary to support the standard from all entities.

#### ***PRC-004-2.1—Analysis and Mitigation of Transmission and Generation Protection System Misoperations***

After examining all standards it had previously reviewed, the SDT elected to propose a slight change to PRC-004-2.1. While the SDT rejected other opportunities to "drop" the phrase "generator interconnection Facility" into requirements because it is not typically the best way to add clarity. In the case of PRC-004-2, the SDT fears that the phrasing of R2 ("The Generator Owner shall analyze its generator Protection System Misoperations...") could lead to some confusion about whether an

interconnection Facility is included. Thus, the SDT proposes adding, “and generator interconnection Facility” as redlined in the draft standard. Because there is no change in applicability, and because the SDT believes that most Generator Owners already interpret the standard in this manner, we consider this to be a minor and not substantive change employed only to add clarity.

***PRC-005-1a—Transmission and Generation Protection System Maintenance and Testing***

In the concurrent 45-day comment and ballot period that ended in November 2011, several commenters pointed out that the wording in R1 and R2 of PRC-005-1a requires the same explicit reference to a generator interconnection Facility that was added in PRC-004-2.1 R2. The SDT agrees and is developing revisions to PRC-005-1a. These will be posted (separate from the recirculation ballot posting) soon.

**Review of Other Standards Considered by the Standard Drafting Team**

To ensure that no reliability gaps were left when the SDT shifted its strategy from the original strategy of the Ad Hoc Group, the SDT reviewed all standards for which the Ad Hoc Group had proposed changes, and again discussed whether making these standards applicable to Generator Owners or Generator Operators would increase reliability with respect to generator requirements at the transmission interface. During the 45-day concurrent comment and ballot period that ended in November 2011, the SDT also received comments from NERC staff encouraging it to review additional standards that NERC staff had proposed to apply to Generator Owners and Generator Operators in [NERC Compliance Process Directive #2011-CAG-001 Regarding Generator Transmission Leads](#) (Directive). Similarly, stakeholder commenters encouraged the SDT to review standards cited in FERC’s Order Denying Compliance Registry Appeals of Cedar Creek Wind Energy and Milford Wind Corridor Phase I (135 FERC ¶ 61,241) (FERC Order).

The SDT reviewed all of these standards and requirements again and continues to find clear and technical reliability-based reasons that support not adding Generator Owner and Generator Operator requirements to the standards. The chart below indicates where else (the Ad Hoc Report, the NERC Directive, or the FERC Order) the standards addressed were discussed. While both the NERC Directive and FERC Orders address specific requirements within these standards, the SDT has found it useful to address each standard as a whole. Often, requirements within a standard, or even from standard to standard, work in concert to ensure that there are no reliability gaps, whereas a review of a requirement in isolation might give the impression that there is gap.

Standard	Ad Hoc Report*	NERC Directive	FERC Order
EOP-003-1	X		
EOP-005-1		X	
FAC-001-0		X	
FAC-003-1 or FAC-003-2	X	X	X
FAC-014-2		X	X

IRO-005-2	X		
PER-001-0	X		
PER-002-0	X	X	
PER-003-1			X
PRC-001-1		X	X
TOP-001-1	X	X	X
TOP-004-2	X	X	X
TOP-006-1		X	
TOP-008-1	X		

\*This chart and accompanying document only address those standards in the Ad Hoc Report for which substantive changes (change in applicability or the addition of a new requirement) were proposed.

The SDT acknowledges that both NERC and FERC have stated that neither the NERC Directive nor the FERC Order is intended to prejudge the work of the SDT. The SDT also acknowledges that the discussion in the FERC Order is related to specific cases in which certain entities will actually be registered as Transmission Owners and Transmission Operators, a process that is distinct from the SDT’s work, which assumes that once this project is complete, Generator Owners and Generator Operators will not be registered for any other functions based on ownership of a sole-use generator interconnection Facility. Still, because these related efforts are ongoing, the SDT thought it would be useful to directly address some of the discussion in the Directive and the Order. The rest of this document provides the SDT’s technical justification for limiting the scope of its work to FAC-001, FAC-003, PRC-004, and PRC-005.

***EOP-003-1—Load Shedding Plans (addressed in the Ad Hoc Report)***

For EOP-003-1, the Ad Hoc Group originally proposed that Generator Operators be added to the requirement that requires Transmission Operators and Balancing Authorities to coordinate automatic load-shedding throughout their areas. The SDT determined that this addition was unnecessary because PRC-001 already includes the requirement that Transmission Operators coordinate their underfrequency load shedding programs with underfrequency isolation of generating units, which implies that Generator Operators need to provide their underfrequency settings to their respective Transmission Operator. Further, Generator Operators typically do not have the technical expertise or access to the data necessary for the high-level coordination that this standard requires.

***EOP-005-1—System Restoration Plans (addressed in the NERC Directive)***

In its Directive, NERC staff states the following by way of rationale for applying EOP-005-1 Requirements R1, R2, R5, R6, and R7 to Generator Operators:

“If GOP has blackstart capability, then EOP-005 applies, GOP restoration plan would require coordination with TOP per the TOP Blackstart Restoration Plan. The GOP would start its

blackstart resources to provide necessary real and reactive power to its generating resources per interconnecting TOP directives. In addition, if GOP has blackstart capability the interconnection TOP will have included this capability in its restoration planning for its area of responsibility. If GOP does not have blackstart capability, GOP restoration plan is dependent upon provision of real and reactive power service from interconnecting TOP, per VAR-001 and VAR-002 requiring the GOP to follow the directives of the interconnecting TOP, compliance with this standard/requirements is not required.”

Blackstart capability of a generating unit is unrelated to owning or operating transmission Facilities or a generation interconnection Facility. During a system restoration event, Generator Operators provide real and reactive power to the BES only at the direction of a Transmission Operator. The Generator Operators are not providing Transmission Operator services through their blackstart Facilities. In addition, many units with blackstart capability are not included in a TOP System Restoration Plan.

In FERC Order 693, Paragraph 630, FERC approved EOP-005-1 and found the standard “adequately addresses operating personnel training and system restoration plans to ensure that transmission operators, balancing authorities and reliability coordinators are prepared to restore the Interconnection following a blackout. Accordingly, the Commission approves Reliability Standard EOP-005-1 as mandatory and enforceable. In addition, pursuant to Section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP-005-1 through the Reliability Standards development process that identifies time frames for training and review of restoration plan requirements.”

FERC also specifically addressed system restoration training concerns and requirements in FERC Order 693 in its review and approval of Reliability Standard EOP-005-1. In that order, FERC stated that personnel outside a control room should be trained in system restoration, but also that this should be included in a system restoration Reliability Standard, as follows:

627. With regard to comments that the Commission’s concerns are being addressed in NERC’s drafting of proposed PER-005-1 Reliability Standard on operator training, we note PER-005-1 only includes Requirements on the control room personnel and not those outside of the control room. System restoration requires the participation of not only control room personnel but also those outside of the control room. These include blackstart unit operators and field switching operators in situations where SCADA capability is unavailable. As such, the Commission believes that inclusion of periodic system restoration drills and training and review of restoration plans in a system restoration Reliability Standard is the most effective way of achieving the desired goal of ensuring that all participants are trained in system restoration and that the restoration plans are up to date to deal with system changes.

Thus, FERC clearly found that the existing standard EOP-005-1 adequately addressed operating personnel training and would ensure the restoration of the BES in the event of a blackstart, and further directed that any modifications be addressed through the Reliability Standard Development Process.

Pursuant to Order 693, NERC initiated Project 2006-03, and empowered the System Restoration and Blackstart Standard Drafting Team (SRBSDT) to modify the related standards. The SRBSDT developed Reliability Standard EOP-005-2, which includes Generator Operator system restoration requirements including training, restoration plans, drills, and testing of blackstart resources. In Order 749, FERC approved EOP-005-2, which included its approval of the implementation plan for EOP-005-2. Again, both FERC and NERC had the opportunity to identify issues with the implementation time of EOP-005-2 and declined to do so.

5. Currently effective Reliability Standard EOP-005-1 requires transmission operators, balancing authorities, and reliability coordinators to have a restoration plan, test the plan, train operating personnel in the restoration plan, and have the ability to restore the Interconnection using the plans following a blackout. In Order No. 693, the Commission directed the ERO to develop, through the Reliability Standard development process, a modification to EOP-005-1 that identifies time frames for training and review of restoration plan requirements to simulate contingencies and prepare operators for anticipated and unforeseen events . . .

Also, in FERC Order 749, both NERC and FERC identified the modifications to EOP-005 as “improvements” to the standard, not changes to close a reliability gap:

10. NERC states that the proposed Reliability Standards “represent significant revision and improvement from the current set of enforceable standards” and address the Commission’s directives in Order No. 693 related to the EOP standards. NERC explains that, among other enhancements, “[t]he proposed revisions now clearly delineate the responsibilities of the Reliability Coordinator and Transmission Operator in the restoration process and restoration planning.” NERC describes the proposed Reliability Standards as providing “specific requirements for what must be in a restoration plan, how and when it needs to be updated and approved, what needs to be provided to operators and what training is necessary for personnel involved in restoration processes.

17. . . . By enhancing the rigor of the restoration planning process, the Reliability Standards represent an improvement from the current Standards and will improve the reliability of the Bulk-Power System. . . .

In summary, the Generator Operator blackstart requirements have been already been appropriately addressed through the Reliability Standards Development Process. EOP-005-2 will become effective in

2013 as approved by both the NERC Board of Trustees and FERC. There is no existing reliability gap related to owning a generation interconnection Facility and Standard EOP-005-1.

***FAC-014-2—Establish and Communicate System Operating Limits (addressed in the NERC Directive and the FERC Order)***

FAC-014-2, R2 states “The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator’s SOL Methodology.”

In its Directive, NERC states, with respect to FAC-014-2: “In the event an RC directs the establishment of an SOL, the SOL must be established in accordance with the RC’s SOL Methodology.”

In Paragraphs 68 and 84 of the FERC Order, FERC states that without compliance with FAC-014, R2, the entity in questions could “avoid establishing the system operating limit for its line or be allowed to establish an operating limit for its line that is not consistent with the requirements of the reliability coordinator’s methodology.”

The SDT does not believe that FAC-014-2 R2 should be revised to include Generator Operators. The Generator Owner is required by the FERC-approved versions of FAC-008-1 R1 and FAC-009-1 and pending FAC-008-3 R1, R2, and R6 (which has been filed for approval with FERC) to document the Facility Ratings for a Generator Owner-owned generator interconnection circuit greater than 100kV. The established Facility Rating must respect the most limiting applicable equipment rating in the circuit and must consider operating limitations and ambient conditions. The thermal or ampere rating of this circuit would equal its ampere operating limit and should be conveyed by the Generator Owner to the Generator Operator if they are not the same entity. The operating voltage limits for this circuit are established by the applicable Transmission Owner or Transmission Operator, not the Generator Owner or Generator Operator.

Therefore, we believe adding the Generator Owner to FAC-014-2 R2 would be redundant. What’s more, the SDT is concerned that entities with a limited view of the system should not be setting IROs or SOLs. We believe this should be the responsibility of entities with a wide-area view, as shown in the standard today; otherwise, we are concerned that reliability may be jeopardized. Commenters – including one from the Transmission Owner segment – have offered this same justification.

***IRO-005-2—Reliability Coordination – Current Day Operations (addressed in the Ad Hoc Report)***

The SDT chose not to adopt the revision to IRO-005-2 proposed by the Ad Hoc Group. This revision would have added a new requirement that would read, “The Generator Operator shall immediately inform the Transmission Operator of the status of the Special Protection System, including any degradation or potential failure to operate as expected for SPS relay or control equipment under its control.” The SDT initially determined that IRO-005-2 did not require modification because of the

October 2011 retirement of the standard. In subsequent meetings, the SDT also reached the conclusion that there is no reliability gap as PRC-001-1 R2 already requires the Generator Operator to notify reliability entities of relay or equipment failures. The SDT believes that a Special Protection System is a form of protection system and therefore any degradation or potential failure to operate as expected would be required to be reported by the Generator Operator to reliability entities (Balancing Authorities, Transmission Operators, and Reliability Coordinators).

***PER Standards (PER-001-0 and PER-002-0 were addressed in the Ad Hoc Report; PER-002-0 was addressed in the NERC Directive; and PER-003-1 was addressed in the FERC Order)***

The Ad Hoc Group had proposed changes to PER-001-0—Operating Personnel Responsibility and Authority and PER-002-0—Operating Personnel Training. For PER-001-0, the Ad Hoc Group proposed adding a new R2 that would read, “Each Generator Operator shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Generation Facility and Generation Interconnection Facility, and the responsibility and authority to follow the directives of reliability authorities including the Transmission Operator and Balancing Authority.” To PER-002-0, the Ad Hoc Group proposed adding the Generator Operator to R1 (“Each Transmission Operator, Generator Operator, and Balancing Authority shall be staffed with adequately trained operating personnel”) and adding a new R3 that would read: “Each Generator Operator shall implement an initial and continuing training program for all operating personnel that are responsible for operating the Generator Interconnection Facility that verifies the personnel’s ability and understanding to operate the equipment in a reliable manner.”

In its Directive, NERC does not address PER-001-0, but it states the following with respect to PER-002-0:

“The registered entity will develop an appropriate training program that contains the necessary elements for the GO/GOP operating a transmission facility to understand fully the impacts of the operation on the BPS, such as equipment involved, including protection systems, the coordination aspects with the TO/TOP to which it is connected, and the protocols for and impacts of operating facilities associated with the transmission facility. The objective of this training is to ensure that the GO/GOP is completely aware of its obligations to follow the directives of the appropriate TOP and has personnel with the skills and training to execute these obligations in the best interest of reliability.”

These proposed changes to the PER standards have little to do with responsibilities that relate specifically to a generator interconnection Facility. Issues related to the training of Generator Operators existed separately from the work of Project 2010-07, and the SDT agrees that its scope limits its efforts to standards that are directly related to generator requirements at the transmission interface. The SDT also cites past FERC Orders as proof that this issue is not within the scope of Project 2010-07. In Order 693, FERC directed NERC to “...expand the applicability of the personnel training Reliability Standard, PER-002-0, to include (i) generator operators centrally-located at a generation



control center with a direct impact on the reliable operation of the Bulk-Power System..." In Order 742, FERC reaffirmed this, stating that it is "...not modifying the Order No. 693 directive regarding training for certain generator operator dispatch personnel, nor are we expanding a generator operator's responsibilities."

Centrally-located generator operators working at a generation control center typically dispatch the output from multiple generating units. As such, they can be called upon to comply with orders from their Balancing Authority that may have a significant impact on the reliable operation of the BES. Their training would be covered by proposed changes to PER-002-0 and Order 742. Generator Operators who deal with interconnection Facilities at individual generating plants, on the other hand, typically do not receive reliability-based orders specific to the interconnection Facilities, and are, therefore, not covered by Order 742. Further, the SDT believes there is no reliability gap, as TOP-001-1 R3 already requires Generator Operators to follow the directives of the appropriate Transmission Operators.

These training-related items are clearly important ones for the Commission, but the SDT does not think it is appropriate to fold modifications to these PER standards into the scope of its work unless it is specifically directed to do so. For now, modifications to PER-002-0 based on Order 693 directives are already included in [NERC's Issue Database](#) (P. 52-53) to be addressed by a future project. PER-001-0 is not addressed in the issues database, but the [Project 2007-03 drafting team has proposed](#) that the standard be retired.

The FERC Order does not address PER-001-0 or PER-002-0, but it does address PER-003-1. In Paragraphs 67 and 81 of the FERC Order, FERC expresses concern that operational control over the transmission line breakers owned by the entities in question are not under the control of NERC certified operators. FERC goes on to say that, "Reliability Standard PER-003-001 requires NERC certification of all operators that have responsibility for the real-time operation of the interconnected Bulk Electric System. When switching the tie-line in or out of service, operators must have the appropriate credentials and training to properly perform the switching and coordinate the switching to prevent adverse impacts such as the introduction of faults on the system."

The SDT can find no evidence that the kinds of training requirements for operating the breakers of the generator interconnection Facility cited in the FERC Order exist elsewhere for other entities that operate breakers on lines. For instance, Transmission Owners that are not also Transmission Operators are not required to undergo any sort of training. The SDT does not mean to dismiss this issue altogether, and it may be that training should be expanded to include Generator Owners, Generator Operators, Transmission Owners, end users, and possibly others; but the development of such requirements would have implications far beyond the scope and expertise of this team.

***PRC-001-1—System Protection Coordination (addressed in the NERC Directive and the FERC Order)***



The NERC Directive addresses PRC-001-1 R2, R2.2, and R4. The FERC Order addresses these requirements, along with Requirement R6.

About R2 and R4, NERC's Directive simply states: "PRC-001-R2 requires notification and corrective action for relay or equipment failure. R4 coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities."

In Paragraphs 64 and 78 of the FERC Order, FERC expresses concern that "...there is a risk of an adverse impact on reliability if the protection relays or protection systems on the [entity's] line are not coordinated with those on the transmission network facilities in its area."

Generator Operators and the scope of protection equipment for generation interconnection Facilities are already appropriately accounted for in this standard in requirement R2 and sub-requirement R2.2. The language used in R2 that applies to the Generator Operator uses the general terms "relay or equipment failures" which would include not only generator relaying, but generator interconnection relaying in the Generator Operator's scope, as well. The Generator Operator is required to notify the Transmission Operator and Host Balancing Authority in R2.1 "...if a protective relay or equipment failure reduces system reliability." Requirement R2.2 requires the affected Transmission Operator to notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. Thus, applying R2.2 to a Generator Operator would be redundant to R2.1. If a Generator Operator had a relay or equipment failure on its Facility, including its interconnection Facility, it would be required to report that to its Transmission Operator under R2.1, and the Transmission Operator is then required to notify its Reliability Coordinator and other affected Transmission Operators and Balancing Authorities under R2.2.

PRC-001-1 R4 states, "Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities." A sole-use generator interconnection Facility does not constitute a major transmission line or major interconnection with neighboring Generator Operators, Transmission Operators, and Balancing Authorities. Thus, R4 should not be revised to include Generator Operators. In general, any coordination that might be required is covered by the fact that the Transmission Operator that is connected to a major transmission lines or interconnection has the requirement to coordinate protection on the interconnection, and there is no reliability gap.

PRC-001-1 R6 states, "Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status." It is clearly the responsibility of the Transmission Operator and/or Balancing Authority to monitor the Special Protection System, as they are the entity with a wide-area view, not the responsibility of a Generator Owner/Generator Operator with a local-

area view who happens to have generator interconnection Facilities in the area. The requirement focuses on the Transmission Operator and Balancing Authority monitoring the status of each Special Protection System *in their area*; there is no “area” for the Generator Operator to monitor. For these reasons, there is no need to make this requirement applicable to Generator Operators.

***TOP-001-1—Reliability Responsibilities and Authority (addressed in the Ad Hoc Report, NERC Directive, and FERC Order)***

Both the NERC Directive and the FERC Order discuss making TOP-001-1 R1 applicable to Generator Operators. About TOP-001-1, the NERC Directive simply states: “TOP-001-1 R1 ensures personnel assigned to operate BES transmission facilities have clear and unambiguous authority to operate those facilities.” With respect to R1, Paragraphs 68 and 83 of FERC’s Order focus on ensuring that “system operators have the authority to take actions to maintain Bulk-Power System facilities within operating limits.”

TOP-001-1 R1 states, “Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.” TOP-001-1 R3 appropriately requires the GOP to comply with reliability directives issued by the Transmission Operator “...unless such actions would violate safety, equipment, regulatory or statutory requirements.” These requirements effectively give the Transmission Operator the necessary decision-making authority over operation of all generator Facilities up to the point of interconnection. Thus, no changes to TOP-001-1 are necessary.

Additionally, the Ad Hoc Group proposed adding two new requirements to TOP-001-1. The first was proposed as R9 and read: “The Generator Operator shall coordinate the operation of its Generator Interconnection Facility with the Transmission Operator to whom it interconnects in order to preserve Interconnection reliability...” The SDT does not agree that TOP-001-1 needs to apply to Generator Operators in any form. TOP-002-2 R3 (proposed to be covered in the future by TOP-003-2, as outlined in Project 2007-03’s Implementation Plan) already requires the Generator Operator to coordinate its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. These entities are, in turn, required to coordinate with their respective Transmission Operator. Additionally, TOP-002-2 R4 (proposed to be covered in the future by TOP-003-2, as outlined in Project 2007-03’s Implementation Plan) requires each Balancing Authority and Transmission Operator to coordinate with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator. With these requirements, Generator Operators are already required to provide necessary operations information to Transmission Operators. To require the same thing in TOP-001-1 would be redundant.

The second new requirement proposed by the Ad Hoc Group for TOP-001-1 was R10, which was to read: “The Transmission Operator shall have decision-making authority over operation of the

Generator Interconnection Operational Interface at all times in order to preserve Interconnection reliability.” As cited above, TOP-002-2 R3 (proposed to be covered in the future by TOP-003-2, as outlined in Project 2007-03’s Implementation Plan) already requires the Generator Operator to coordinate with its interconnecting Transmission Operator. Further, TOP-001-1 R3 (proposed to be covered in the future in the proposed IRO-001-2 R2 and R3) already requires the Generator Operator to comply with reliability directives issued by the Transmission Operator. These requirements effectively give the Transmission Operator decision-making authority over operation of all generator Facilities up to the point of interconnection. To require the same thing in TOP-001-1 would be redundant.

***TOP-004-2—Transmission Operations (addressed in the NERC Directive and the FERC Order)***

Both the NERC Directive and the FERC Order address the application of TOP-004-2 R6 to Generator Operators. In its Directive, NERC simply states: “TOP-004-2 R6 ensures formal policies and procedures are formulated to provide for coordination of activities that may impact reliability.” In Paragraphs 67 and 82 of the FERC Order, FERC talks about entities ensuring the development of coordination protection to coordinate switching a generator interconnection Facility in and out of service, since different entities have control over different ends of the line. FERC concludes that for the entities in question, TOP-004-2 R6 must apply.

Requirement R6 and its sub-requirements state: “R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: R6.1. Monitoring and controlling voltage levels and real and reactive power flows, R6.2. Switching transmission elements, R6.3. Planned outages of transmission elements, R6.4. Responding to IROL and SOL violations.”

TOP-001-1 R3 appropriately requires the Generator Operator to comply with reliability directives issued by the Transmission Operator. These requirements give the Transmission Operator the necessary decision-making authority over operation of all generator Facilities, including interconnection Facilities, up to the point of interconnection. Further, TOP-002-2 R3 requires the Generator Owner to coordinate its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. These entities are, in turn, required to coordinate with their respective Transmission Operators (also in TOP-002-2 R3). Each Balancing Authority and Transmission Operator is also then required to coordinate with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator (in TOP-002-2 R4). The coordination with which NERC and FERC are concerned is already addressed by these other requirements.

The Ad Hoc Group had proposed a new requirement, R7, for TOP-004-2 that would read: “The Generator Operator shall operate its Generator Interconnection Facility within its applicable ratings.” The SDT does not agree that a reliability gap exists, because an operator has a fiduciary obligation to protect a Facility for which it is operationally responsible. FAC-008-1—Facility Ratings Methodology and FAC-009-1—Establish and Communicate Facility Ratings already infer that the reason for establishing a ratings methodology and communicating Facility Ratings to the Reliability Coordinator, Planning Authority, Transmission Planner, and Transmission Operator is “...for use in reliable planning and operation of the Bulk Electric System.” Further, TOP-004-2 is proposed to be retired under the work of the Project 2007-03 drafting team. Its requirements will either be deleted or assigned elsewhere.

***TOP-006-1—Monitoring System Conditions (addressed in the NERC Directive; the SDT believes NERC intended to refer to TOP-006-2)***

Only the NERC Directive addresses TOP-006. It states: “TOP-006-1 R3 ensures technical information is provided to the responsible personnel; R6 ensures correct and accurate data to TOP and BA.” But PRC-001-1 R1 (“Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area”) addresses the necessary Generator Operator requirements with respect to TOP-006-2 R3. The SDT believes that knowledge of the purpose and limitations of protection system schemes applied in its area (required in PRC-001-1 R1) constitutes knowledge of “the appropriate technical information concerning protective relays” (required in TOP-006-1 R3).

TOP-006-2 R6 states: “Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.” FAC-001-1 R2.1.6 already requires the Transmission Owner’s facility connection requirements to address “metering and telecommunications.” Any generator Facility that interconnected with a Transmission Owner would have had to meet their Facility connection and system performance requirements for metering and telecommunications. Thus, there is no reliability gap.

***TOP-008-1—Response to Transmission Limit Violations (addressed in the Ad Hoc Report)***

Only the Ad Hoc Report addressed TOP-008-1, and it proposed a new requirement, R5, to TOP-008-1—Response to Transmission Limit Violations that would read, “The Generator Operator shall disconnect the Generator Interconnection Facility when safety is jeopardized or the overload or abnormal voltage or reactive condition persists and generating equipment or the Generator Interconnection Facility is endangered. In doing so, the Generator Operator shall notify its Transmission Operator and Balancing Authority impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.” The SDT sees no reliability benefit to adding this requirement. TOP-001-1 R7 (“Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless...”) and its parts give the

Generator Operator authority over its Facilities, which would include the generator interconnection Facility. If there is an outage, R7.1 requires the Generator Operator to notify and coordinate with its Transmission Operator, which is required to notify the Reliability Coordinator and other affected Transmission Operators. And as with TOP-004-2, the Project 2007-03 drafting team has proposed to delete all of TOP-008-1's requirements and retiring the standard.

**Conclusion**

The Project 2010-07 SDT is confident that the changes it has proposed address the reliability gap that exists with respect to the responsibilities of Generator Owners and Generator Operations that own sole-use interconnection Facilities. The changes to FAC-001, FAC-003, and PRC-004 have been supported by stakeholders during comment periods, and there has been no strong support of technical justification provided for bringing other standards into the scope of this project.

# Technical Justification Resource Document

## Project 2010-07 Generator Requirements at the Transmission Interface

### Background

As part of its work on Project 2010-07—Generator Requirements at the Transmission Interface, the standard drafting team (SDT) reviewed 34 reliability standards and 102 requirements to determine what changes are necessary to close a reliability gap with respect to what is commonly known as the generator interconnection Facility. Many of these standards and requirements had been addressed in the [Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface](#) (Ad Hoc Report) and additional standards were reviewed as a result of informal discussions with NERC and FERC staffs.

The SDT's technical justification document has not changed substantively since it was posted in December 2011, but the document below has been updated to reflect the posted changes to FAC-003-3 and FAC-003-X.

The basis for standard modifications recommended by the Ad Hoc Group for Generator Requirements at the Transmission Interface (Ad Hoc Group) was a few fundamental clarifications to the definitions of Generator Owner, Generator Operator, and Transmission, along with the creation of new definitions: one for Generator Interconnection Facility and one for Generator Interconnection Operational Interface. The Ad Hoc Group proposed the addition of these two new definitions to 26 standards encompassing 29 requirements (new and old), along with some modifications to FAC-003 to make it applicable to Generator Owners under certain circumstances.

Since the publication of the Ad Hoc Report, various entities have challenged these modifications and the recommended creation of the new definitions. The SDT has developed a more focused approach than that of the Ad Hoc Group: to propose recommendations whereby sole-use interconnection Facilities (at or above 100 kV) that are owned and operated by generating entities will be included in a small set of standards and requirements previously only applicable to Transmission Owners. The SDT agrees completely with the Ad Hoc Group's conclusion that Generator Owners and Operators of these sole-use generator tie-line Facilities (at voltages equal to or greater than 100 kV) should not be registered as Transmission Owners and Transmission Operators in order to maintain reliability on the Bulk Electric System (BES).

The SDT's justification for this strategy is rooted in the very title of its standards project: "Generator Requirements at the Transmission Interface." That is, the goal and scope of the project has always been to determine the responsibilities of those Generator Owners and Generator Operators that own or operate an interconnection Facility (in some cases labeled a "transmission Facility") between the generator and the interface with the portion of the BES where Transmission Owners and Transmission



Operators take over ownership and operating responsibility. These kinds of Generator Owners and Generator Operators do not own or operate Facilities that are part of the interconnected system; rather, they own and operate sole-use Facilities that are connected to the boundary of the interconnected system and as such have a limited role in providing reliability compared to those that operate in a networked fashion beyond the point of interconnection.

While some argue that these interconnecting portions of a Generator Owner's Facilities could be defined as Transmission and thus require the Generator Owner and Generator Operator for the Facility to be classified and registered as a Transmission Owner and Transmission Operator, the SDT does not believe this is necessary to provide an appropriate level of reliability for the BES. Just as important, such classification and registration could actually cause a reduction in reliability. Generator Owners and Generator Operators do not need, and in some cases may be prohibited from having, a wide-area view and responsibility for the integrated transmission system. Requiring Generator Owners and Generator Operators to have such responsibilities would require significant training, require substantially more data and modeling responsibilities, and detract from the entities' primary functions: to own and operate their generation equipment – including any Facilities owned and operated at voltages of 100 kV or greater that connect to the interconnected system – in a reliable manner.

Additionally, the SDT believes that the industry is much more aware today of the need to include *all* elements (owned and operated at 100 kV or higher) of a generator Facility in the procedures and compliance program of the registered entity that owns or has operational responsibility of those elements. Industry awareness was raised substantially at the time the [October 17, 2010 Facility Ratings Recommendation to Industry](#) was issued (which included Generator Owners and specifically addressed interconnection Facilities in [the Q&A document](#) with the statement that the alert applied to generator interconnection tie lines that are radial only and do not serve load “if the generator is considered part of the bulk electric system”). While this applies to a specific NERC Recommendation, the SDT considers this compelling evidence that the paradigm for thinking about generator interconnection Facilities is shifting.

All of this has led the SDT to its current conclusions to modify FAC-001, FAC-003, and PRC-004 and later, PRC-005. The SDT does not believe any further modifications to standards are necessary to maintain an appropriate level of reliability based on the revised assumption that while generator Facilities (at 100 kV and above) will be considered by some to be transmission, Generator Owners and Generator Operators should not be registered as Transmission Owners and Transmission Operators simply as a result of the ownership and operation of such Facilities. Because the majority of commenters support the SDT's current recommendation to not adopt new terms, the SDT has elected to focus on its standard changes and not, at this time, propose revisions to existing, or creation of new, glossary terms.

Below, the SDT discusses the changes it has proposed for FAC-001, FAC-003, and PRC-004 and the changes it plans to propose for PRC-005 and then provides justification for not modifying any of the additional standards and requirements it has reviewed.

## **Review of SDT's Proposed Standard Changes**

### ***FAC-001-1—Facility Connection Requirements***

While some stakeholders have questioned the modifications in the proposed FAC-001-1, the SDT remains convinced that there is the potential for a reliability gap if this standard is not modified so that it applies to a Generator Owner *if and when it executes an Agreement* to evaluate the reliability impact of interconnecting a third party Facility to its existing generation interconnection Facility. The intent of this modified language is to start the compliance clock when the Generator Owner executes an Agreement to perform the reliability assessment required in FAC-002-1. This step is expected to occur if a Generator Owner is compelled by a regulatory body to allow such interconnection. Assuming that a regulatory body would require a Generator Owner to evaluate such an interconnection request, the SDT expects the Generator Owner and the third party to execute some form of an Agreement. The SDT intentionally excluded a specific reference to the form of Agreement (such as a feasibility study) in deference to stakeholder suggestions to avoid comingling of commercial and reliability issues in reliability standards.

The SDT acknowledges that the scenario described in the proposed FAC-001-1 may be rare, but in the past (for instance, FERC ¶ 61,109 at P. 19 and 134 FERC ¶ 61,064 at P. 13), Generator Owners have received or have been directed to execute interconnection requests for their Facilities, and the SDT thinks it is important to clarify the responsibilities related to such a request in NERC's Reliability Standards. And, while the SDT acknowledges that such regulatory action might also result in the Generator Owner being registered for other functions, such as Transmission Owner, Transmission Planner, and/or Transmission Service Provider, it decided the proposed revision provides appropriate reliability coverage until any additional registration is required and does not impact any Generator Owner that never executes an Agreement as described in the standard.

### ***FAC-003-X and FAC-003-3—Vegetation Management***

The SDT and most stakeholders agree with the Ad Hoc Group recommendation that FAC-003 be applicable to Generator Owners that own a generation interconnection Facility if that Facility contains overhead conductors. The Ad Hoc Group originally excluded such a Facility from this requirement if its length is less than two spans (generally one half mile from the generator property line). The SDT agrees with that intended exclusion in principle; as it discusses in the document titled "[Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface](#)," the SDT recognizes that in many cases, generation Facilities are (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale for exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit.



Thus, the SDT has maintained this exception language but has modified it based on stakeholder input such that it excludes Facilities shorter than one mile which have a clear line of sight from the fenced area of the generating switchyard to the point of interconnection. Specifically, to clarify the exemption, the SDT has modified 4.3.1 to include a reference to line of sight. 4.3.1 of FAC-003-X now reads:

Generator Owner that owns an applicable qualified Facility, where a qualified Facility is an overhead transmission line(s) that (1) extends greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner’s Facility or (2) does not have a clear line of sight from the generating station switchyard fence to the point of interconnection with a Transmission Owner’s Facility and is operated at 200 kV and above and any lower voltage lines designated by the Regional Entity as critical to the reliability of the electric system in the region.

4.3.1 of FAC-003-3 now reads:

Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner’s Facility or (2) do not have a clear line of sight from the generating station switchyard fence to the point of interconnection with a Transmission Owner’s Facility and are: Operated at 200kV or higher; or operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

Both references to clear line of sight include a footnote stating: “‘Clear line of sight’ means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.”

The SDT took into consideration all comments submitted in both formal comment periods, and believes that this exemption now adequately addresses the reliability impact for a majority of the Facilities, while balancing the efforts necessary to support the standard from all entities.

***PRC-004-2.1—Analysis and Mitigation of Transmission and Generation Protection System Misoperations***

After examining all standards it had previously reviewed, the SDT elected to propose a slight change to PRC-004-2.1. While the SDT rejected other opportunities to “drop” the phrase “generator interconnection Facility” into requirements because it is not typically the best way to add clarity, in the case of PRC-004-2, the SDT fears that the phrasing of R2 (“The Generator Owner shall analyze its generator Protection System Misoperations...”) could lead to some confusion about whether an interconnection Facility is included. Thus, the SDT proposes adding “and generator interconnection

Facility” as redlined in the draft standard. Because there is no change in applicability, and because the SDT believes that most Generator Owners already interpret the standard in this manner, we consider this to be a minor and not substantive change employed only to add clarity.

**PRC-005-1a—Transmission and Generation Protection System Maintenance and Testing**

In the concurrent 45-day comment and ballot period that ended in November 2011, several commenters pointed out that the wording in R1 and R2 of PRC-005-1a requires the same explicit reference to a generator interconnection Facility that was added in PRC-004-2.1 R2. The SDT agrees and is developing revisions to PRC-005-1a. These will be posted (separate from the recirculation ballot posting) soon.

**Review of Other Standards Considered by the Standard Drafting Team**

To ensure that no reliability gaps were left when the SDT shifted its strategy from the original strategy of the Ad Hoc Group, the SDT reviewed all standards for which the Ad Hoc Group had proposed changes, and again discussed whether making these standards applicable to Generator Owners or Generator Operators would increase reliability with respect to generator requirements at the transmission interface. During the 45-day concurrent comment and ballot period that ended in November 2011, the SDT also received comments from NERC staff encouraging it to review additional standards that NERC staff had proposed to apply to Generator Owners and Generator Operators in [NERC Compliance Process Directive #2011-CAG-001 Regarding Generator Transmission Leads](#) (Directive). Similarly, stakeholder commenters encouraged the SDT to review standards cited in FERC’s Order Denying Compliance Registry Appeals of Cedar Creek Wind Energy and Milford Wind Corridor Phase I (135 FERC ¶ 61,241) (FERC Order).

The SDT reviewed all of these standards and requirements again and continues to find clear and technical reliability-based reasons that support not adding Generator Owner and Generator Operator requirements to the standards. The chart below indicates where else (the Ad Hoc Report, the NERC Directive, or the FERC Order) the standards addressed were discussed. While both the NERC Directive and FERC Orders address specific requirements within these standards, the SDT has found it useful to address each standard as a whole. Often, requirements within a standard, or even from standard to standard, work in concert to ensure that there are no reliability gaps, whereas a review of a requirement in isolation might give the impression that there is gap.

Standard	Ad Hoc Report*	NERC Directive	FERC Order
EOP-003-1	X		
EOP-005-1		X	
FAC-001-0		X	
FAC-003-1 or FAC-003-2	X	X	X
FAC-014-2		X	X
IRO-005-2	X		

PER-001-0	X		
PER-002-0	X	X	
PER-003-1			X
PRC-001-1		X	X
TOP-001-1	X	X	X
TOP-004-2	X	X	X
TOP-006-1		X	
TOP-008-1	X		

\*This chart and accompanying document only address those standards in the Ad Hoc Report for which substantive changes (change in applicability or the addition of a new requirement) were proposed.

The SDT acknowledges that both NERC and FERC have stated that neither the NERC Directive nor the FERC Order is intended to prejudge the work of the SDT. The SDT also acknowledges that the discussion in the FERC Order is related to specific cases in which certain entities will actually be registered as Transmission Owners and Transmission Operators, a process that is distinct from the SDT’s work, which assumes that once this project is complete, Generator Owners and Generator Operators will not be registered for any other functions based on ownership of a sole-use generator interconnection Facility. Still, because these related efforts are ongoing, the SDT thought it would be useful to directly address some of the discussion in the Directive and the Order. The rest of this document provides the SDT’s technical justification for limiting the scope of its work to FAC-001, FAC-003, PRC-004, and PRC-005.

***EOP-003-1—Load Shedding Plans (addressed in the Ad Hoc Report)***

For EOP-003-1, the Ad Hoc Group originally proposed that Generator Operators be added to the requirement that requires Transmission Operators and Balancing Authorities to coordinate automatic load-shedding throughout their areas. The SDT determined that this addition was unnecessary because PRC-001 already includes the requirement that Transmission Operators coordinate their underfrequency load shedding programs with underfrequency isolation of generating units, which implies that Generator Operators need to provide their underfrequency settings to their respective Transmission Operator. Further, Generator Operators typically do not have the technical expertise or access to the data necessary for the high-level coordination that this standard requires.

***EOP-005-1—System Restoration Plans (addressed in the NERC Directive)***

In its Directive, NERC staff states the following by way of rationale for applying EOP-005-1 Requirements R1, R2, R5, R6, and R7 to Generator Operators:

“If GOP has blackstart capability, then EOP-005 applies, GOP restoration plan would require coordination with TOP per the TOP Blackstart Restoration Plan. The GOP would start its blackstart resources to provide necessary real and reactive power to its generating resources

per interconnecting TOP directives. In addition, if GOP has blackstart capability the interconnection TOP will have included this capability in its restoration planning for its area of responsibility. If GOP does not have blackstart capability, GOP restoration plan is dependent upon provision of real and reactive power service from interconnecting TOP, per VAR-001 and VAR-002 requiring the GOP to follow the directives of the interconnecting TOP, compliance with this standard/requirements is not required.”

Blackstart capability of a generating unit is unrelated to owning or operating transmission Facilities or a generation interconnection Facility. During a system restoration event, Generator Operators provide real and reactive power to the BES only at the direction of a Transmission Operator. The Generator Operators are not providing Transmission Operator services through their blackstart Facilities. In addition, many units with blackstart capability are not included in a TOP System Restoration Plan.

In FERC Order 693, paragraph 630, FERC approved EOP-005-1 and found the standard “adequately addresses operating personnel training and system restoration plans to ensure that transmission operators, balancing authorities and reliability coordinators are prepared to restore the Interconnection following a blackout. Accordingly, the Commission approves Reliability Standard EOP-005-1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP-005-1 through the Reliability Standards development process that identifies time frames for training and review of restoration plan requirements.”

FERC also specifically addressed system restoration training concerns and requirements in FERC Order 693 in its review and approval of Reliability Standard EOP-005-1. In that order, FERC stated that personnel outside a control room should be trained in system restoration, but also that this should be included in a system restoration Reliability Standard, as follows:

627. With regard to comments that the Commission’s concerns are being addressed in NERC’s drafting of proposed PER-005-1 Reliability Standard on operator training, we note PER-005-1 only includes Requirements on the control room personnel and not those outside of the control room. System restoration requires the participation of not only control room personnel but also those outside of the control room. These include blackstart unit operators and field switching operators in situations where SCADA capability is unavailable. As such, the Commission believes that inclusion of periodic system restoration drills and training and review of restoration plans in a system restoration Reliability Standard is the most effective way of achieving the desired goal of ensuring that all participants are trained in system restoration and that the restoration plans are up to date to deal with system changes.

Thus, FERC clearly found that the existing standard EOP-005-1 adequately addressed operating personnel training and would ensure the restoration of the BES in the event of a blackstart, and further directed that any modifications be addressed through the Reliability Standard Development Process.

Pursuant to Order 693, NERC initiated Project 2006-03, and empowered the System Restoration and Blackstart Standard Drafting Team (SRBSDT) to modify the related standards. The SRBSDT developed Reliability Standard EOP-005-2, which includes Generator Operator system restoration requirements including training, restoration plans, drills, and testing of blackstart resources. In Order 749, FERC approved EOP-005-2, which included its approval of the implementation plan for EOP-005-2. Again, both FERC and NERC had the opportunity to identify issues with the implementation time of EOP-005-2 and declined to do so.

5. Currently effective Reliability Standard EOP-005-1 requires transmission operators, balancing authorities, and reliability coordinators to have a restoration plan, test the plan, train operating personnel in the restoration plan, and have the ability to restore the Interconnection using the plans following a blackout. In Order No. 693, the Commission directed the ERO to develop, through the Reliability Standard development process, a modification to EOP-005-1 that identifies time frames for training and review of restoration plan requirements to simulate contingencies and prepare operators for anticipated and unforeseen events . . .

Also, in FERC Order 749, both NERC and FERC identified the modifications to EOP-005 as “improvements” to the standard, not changes to close a reliability gap:

10. NERC states that the proposed Reliability Standards “represent significant revision and improvement from the current set of enforceable standards” and address the Commission’s directives in Order No. 693 related to the EOP standards. NERC explains that, among other enhancements, “[t]he proposed revisions now clearly delineate the responsibilities of the Reliability Coordinator and Transmission Operator in the restoration process and restoration planning.” NERC describes the proposed Reliability Standards as providing “specific requirements for what must be in a restoration plan, how and when it needs to be updated and approved, what needs to be provided to operators and what training is necessary for personnel involved in restoration processes.

17. . . . By enhancing the rigor of the restoration planning process, the Reliability Standards represent an improvement from the current Standards and will improve the reliability of the Bulk-Power System. . . .

In summary, the Generator Operator blackstart requirements have been already been appropriately addressed through the Reliability Standards Development Process. EOP-005-2 will become effective in

2013 as approved by both the NERC Board of Trustees and FERC. There is no existing reliability gap related to owning a generation interconnection Facility and Standard EOP-005-1.

***FAC-014-2—Establish and Communicate System Operating Limits (addressed in the NERC Directive and the FERC Order)***

FAC-014-2, R2 states “The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator’s SOL Methodology.”

In its Directive, NERC states, with respect to FAC-014-2: “In the event an RC directs the establishment of an SOL, the SOL must be established in accordance with the RC’s SOL Methodology.”

In paragraphs 68 and 84 of the FERC Order, FERC states that without compliance with FAC-014, R2, the entity in questions could “avoid establishing the system operating limit for its line or be allowed to establish an operating limit for its line that is not consistent with the requirements of the reliability coordinator’s methodology.”

The SDT does not believe that FAC-014-2 R2 should be revised to include Generator Operators. The Generator Owner is required by the FERC-approved versions of FAC-008-1 R1 and FAC-009-1 and pending FAC-008-3 R1, R2, and R6 (which has been filed for approval with FERC) to document the Facility Ratings for a Generator Owner-owned generator interconnection circuit greater than 100kV. The established Facility Rating must respect the most limiting applicable equipment rating in the circuit and must consider operating limitations and ambient conditions. The thermal or ampere rating of this circuit would equal its ampere operating limit and should be conveyed by the Generator Owner to the Generator Operator if they are not the same entity. The operating voltage limits for this circuit are established by the applicable Transmission Owner or Transmission Operator, not the Generator Owner or Generator Operator.

Therefore, we believe adding the Generator Owner to FAC-014-2 R2 would be redundant. What’s more, the SDT is concerned that entities with a limited view of the system should not be setting IROs or SOLs. We believe this should be the responsibility of entities with a wide-area view, as shown in the standard today; otherwise, we are concerned that reliability may be jeopardized. Commenters – including one from the Transmission Owner segment – have offered this same justification.

***IRO-005-2—Reliability Coordination – Current Day Operations (addressed in the Ad Hoc Report)***

The SDT chose not to adopt the revision to IRO-005-2 proposed by the Ad Hoc Group. This revision would have added a new requirement that would read, “The Generator Operator shall immediately inform the Transmission Operator of the status of the Special Protection System, including any degradation or potential failure to operate as expected for SPS relay or control equipment under its control.” The SDT initially determined that IRO-005-2 did not require modification because of the

October 2011 retirement of the standard. In subsequent meetings, the SDT also reached the conclusion that there is no reliability gap as PRC-001-1 R2 already requires the Generator Operator to notify reliability entities of relay or equipment failures. The SDT believes that a Special Protection System is a form of protection system and therefore any degradation or potential failure to operate as expected would be required to be reported by the Generator Operator to reliability entities (Balancing Authorities, Transmission Operators, and Reliability Coordinators).

***PER Standards (PER-001-0 and PER-002-0 were addressed in the Ad Hoc Report; PER-002-0 was addressed in the NERC Directive; and PER-003-1 was addressed in the FERC Order)***

The Ad Hoc Group had proposed changes to PER-001-0—Operating Personnel Responsibility and Authority and PER-002-0—Operating Personnel Training. For PER-001-0, the Ad Hoc Group proposed adding a new R2 that would read “Each Generator Operator shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Generation Facility and Generation Interconnection Facility, and the responsibility and authority to follow the directives of reliability authorities including the Transmission Operator and Balancing Authority.” To PER-002-0, the Ad Hoc Group proposed adding the Generator Operator to R1 (“Each Transmission Operator, Generator Operator, and Balancing Authority shall be staffed with adequately trained operating personnel”) and adding a new R3 that would read: “Each Generator Operator shall implement an initial and continuing training program for all operating personnel that are responsible for operating the Generator Interconnection Facility that verifies the personnel’s ability and understanding to operate the equipment in a reliable manner.”

In its Directive, NERC does not address PER-001-0, but it states the following with respect to PER-002-0:

“The registered entity will develop an appropriate training program that contains the necessary elements for the GO/GOP operating a transmission facility to understand fully the impacts of the operation on the BPS, such as equipment involved, including protection systems, the coordination aspects with the TO/TOP to which it is connected, and the protocols for and impacts of operating facilities associated with the transmission facility. The objective of this training is to ensure that the GO/GOP is completely aware of its obligations to follow the directives of the appropriate TOP and has personnel with the skills and training to execute these obligations in the best interest of reliability.”

These proposed changes to the PER standards have little to do with responsibilities that relate specifically to a generator interconnection Facility. Issues related to the training of Generator Operators existed separately from the work of Project 2010-07, and the SDT agrees that its scope limits its efforts to standards that are directly related to generator requirements at the transmission interface. The SDT also cites past FERC Orders as proof that this issue is not within the scope of Project 2010-07. In Order 693, FERC directed NERC to "expand the applicability of the personnel training Reliability Standard, PER-002-0, to include (i) generator operators centrally-located at a generation



control center with a direct impact on the reliable operation of the Bulk-Power System..." In Order 742, FERC reaffirmed this, stating that it is "not modifying the Order No. 693 directive regarding training for certain generator operator dispatch personnel, nor are we expanding a generator operator's responsibilities."

Centrally-located generator operators working at a generation control center typically dispatch the output from multiple generating units. As such, they can be called upon to comply with orders from their Balancing Authority that may have a significant impact on the reliable operation of the BES. Their training would be covered by proposed changes to PER-002-0 and Order 742. Generator Operators who deal with interconnection Facilities at individual generating plants, on the other hand, typically do not receive reliability-based orders specific to the interconnection Facilities and are therefore not covered by Order 742. Further, the SDT believes there is no reliability gap as TOP-001-1 R3 already requires Generator Operators to follow the directives of the appropriate Transmission Operators.

These training-related items are clearly important ones for the Commission, but the SDT does not think it is appropriate to fold modifications to these PER standards into the scope of its work unless it is specifically directed to do so. For now, modifications to PER-002-0 based on Order 693 directives are already included in [NERC's Issue Database](#) (P. 52-53) to be addressed by a future project. PER-001-0 is not addressed in the Issues Database, but the [Project 2007-03 drafting team has proposed](#) that the standard be retired.

The FERC Order does not address PER-001-0 or PER-002-0, but it does address PER-003-1. In paragraphs 67 and 81 of the FERC Order, FERC expresses concern that operational control over the transmission line breakers owned by the entities in question are not under the control of NERC certified operators. FERC goes on to say that "Reliability Standard PER-003-001 requires NERC certification of all operators that have responsibility for the real-time operation of the interconnected Bulk Electric System. When switching the tie-line in or out of service, operators must have the appropriate credentials and training to properly perform the switching and coordinate the switching to prevent adverse impacts such as the introduction of faults on the system."

The SDT can find no evidence that the kinds of training requirements for operating the breakers of the generator interconnection Facility cited in the FERC Order exist elsewhere for other entities that operate breakers on lines. For instance, Transmission Owners that are not also Transmission Operators are not required to undergo any sort of training. The SDT does not mean to dismiss this issue altogether, and it may be that training should be expanded to include Generator Owners, Generator Operators, Transmission Owners, end users, and possibly others, but the development of such requirements would have implications far beyond the scope and expertise of this team.

***PRC-001-1—System Protection Coordination (addressed in the NERC Directive and the FERC Order)***



The NERC Directive addresses PRC-001-1 R2, R2.2, and R4. The FERC Order addresses these requirements, along with Requirement R6.

About R2 and R4, NERC's Directive simply states: "PRC-001-R2 requires notification and corrective action for relay or equipment failure. R4 coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities."

In paragraphs 64 and 78 of the FERC Order, FERC expresses concern that "there is a risk of an adverse impact on reliability if the protection relays or protection systems on the [entity's] line are not coordinated with those on the transmission network facilities in its area."

Generator Operators and the scope of protection equipment for generation interconnection Facilities are already appropriately accounted for in this standard in requirement R2 and sub-requirement R2.2. The language used in R2 that applies to the Generator Operator uses the general terms "relay or equipment failures" which would include not only generator relaying, but generator interconnection relaying in the Generator Operator's scope as well. The Generator Operator is required to notify the Transmission Operator and Host Balancing Authority in R2.1 "if a protective relay or equipment failure reduces system reliability." Requirement R2.2 requires the affected Transmission Operator to notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. Thus, applying R2.2 to a Generator Operator would be redundant to R2.1. If a Generator Operator had a relay or equipment failure on its Facility, including its interconnection Facility it would be required to report that to its Transmission Operator under R2.1, and the Transmission Operator is then required to notify its Reliability Coordinator and other affected Transmission Operators and Balancing Authorities under R2.2.

PRC-001-1 R4 states, "Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities." A sole-use generator interconnection Facility does not constitute a major transmission line or major interconnection with neighboring Generator Operators, Transmission Operators, and Balancing Authorities. Thus, R4 should not be revised to include Generator Operators. In general, any coordination that might be required is covered by the fact that the Transmission Operator that is connected to a major transmission lines or interconnection has the requirement to coordinate protection on the interconnection, and there is no reliability gap.

PRC-001-1 R6 states, "Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status." It is clearly the responsibility of the Transmission Operator and/or Balancing Authority to monitor the Special Protection System, as they are the entity with a wide-area view, not the responsibility of a Generator Owner/Generator Operator with a local-

area view who happens to have generator interconnection Facilities in the area. The requirement focuses on the Transmission Operator and Balancing Authority monitoring the status of each Special Protection System *in their area*; there is no “area” for the Generator Operator to monitor. For these reasons, there is no need to make this requirement applicable to Generator Operators.

***TOP-001-1—Reliability Responsibilities and Authority (addressed in the Ad Hoc Report, NERC Directive, and FERC Order)***

Both the NERC Directive and the FERC Order discuss making TOP-001-1 R1 applicable to Generator Operators. About TOP-001-1, the NERC Directive simply states: “TOP-001-1 R1 ensures personnel assigned to operate BES transmission facilities have clear and unambiguous authority to operate those facilities.” With respect to R1, paragraphs 68 and 83 of FERC’s Order focus on ensuring that “system operators have the authority to take actions to maintain Bulk-Power System facilities within operating limits.”

TOP-001-1 R1 states, “Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.” TOP-001-1 R3 appropriately requires the GOP to comply with reliability directives issued by the Transmission Operator “unless such actions would violate safety, equipment, regulatory or statutory requirements.” These requirements effectively give the Transmission Operator the necessary decision-making authority over operation of all generator Facilities up to the point of interconnection. Thus, no changes to TOP-001-1 are necessary.

Additionally, the Ad Hoc Group proposed adding two new requirements to TOP-001-1. The first was proposed as R9 and read: “The Generator Operator shall coordinate the operation of its Generator Interconnection Facility with the Transmission Operator to whom it interconnects in order to preserve Interconnection reliability...” The SDT does not agree that TOP-001-1 needs to apply to Generator Operators in any form. TOP-002-2 R3 (proposed to be covered in the future by TOP-003-2, as outlined in Project 2007-03’s Implementation Plan) already requires the Generator Operator to coordinate its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. These entities are, in turn, required to coordinate with their respective Transmission Operator. Additionally, TOP-002-2 R4 (proposed to be covered in the future by TOP-003-2, as outlined in Project 2007-03’s Implementation Plan) requires each Balancing Authority and Transmission Operator to coordinate with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator. With these requirements, Generator Operators are already required to provide necessary operations information to Transmission Operators. To require the same thing in TOP-001-1 would be redundant.

The second new requirement proposed by the Ad Hoc Group for TOP-001-1 was R10, which was to read: “The Transmission Operator shall have decision-making authority over operation of the

Generator Interconnection Operational Interface at all times in order to preserve Interconnection reliability.” As cited above, TOP-002-2 R3 (proposed to be covered in the future by TOP-003-2, as outlined in Project 2007-03’s Implementation Plan) already requires the Generator Operator to coordinate with its interconnecting Transmission Operator. Further, TOP-001-1 R3 (proposed to be covered in the future in the proposed IRO-001-2 R2 and R3) already requires the Generator Operator to comply with reliability directives issued by the Transmission Operator. These requirements effectively give the Transmission Operator decision-making authority over operation of all generator Facilities up to the point of interconnection. To require the same thing in TOP-001-1 would be redundant.

***TOP-004-2—Transmission Operations (addressed in the NERC Directive and the FERC Order)***

Both the NERC Directive and the FERC Order address the application of TOP-004-2 R6 to Generator Operators. In its Directive, NERC simply states: “TOP-004-2 R6 ensures formal policies and procedures are formulated to provide for coordination of activities that may impact reliability.” In paragraphs 67 and 82 of the FERC Order, FERC talks about entities ensuring the development of coordination protection to coordinate switching a generator interconnection Facility in and out of service, since different entities have control over different ends of the line. FERC concludes that for the entities in question, TOP-004-2 R6 must apply.

Requirement R6 and its sub-requirements state: “R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: R6.1. Monitoring and controlling voltage levels and real and reactive power flows, R6.2. Switching transmission elements, R6.3. Planned outages of transmission elements, R6.4. Responding to IROL and SOL violations.”

TOP-001-1 R3 appropriately requires the Generator Operator to comply with reliability directives issued by the Transmission Operator. These requirements give the Transmission Operator the necessary decision-making authority over operation of all generator Facilities, including interconnection Facilities, up to the point of interconnection. Further, TOP-002-2 R3 requires the Generator Owner to coordinate its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. These entities are, in turn, required to coordinate with their respective Transmission Operators (also in TOP-002-2 R3). Each Balancing Authority and Transmission Operator is also then required to coordinate with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator (in TOP-002-2 R4). The coordination with which NERC and FERC are concerned is already addressed by these other requirements.

The Ad Hoc Group had proposed a new requirement, R7, for TOP-004-2 that would read: “The Generator Operator shall operate its Generator Interconnection Facility within its applicable ratings.” The SDT does not agree that a reliability gap exists, because an operator has a fiduciary obligation to protect a Facility for which it is operationally responsible. FAC-008-1—Facility Ratings Methodology and FAC-009-1—Establish and Communicate Facility Ratings already infer that the reason for establishing a ratings methodology and communicating Facility Ratings to the Reliability Coordinator, Planning Authority, Transmission Planner, and Transmission Operator is “...for use in reliable planning and operation of the Bulk Electric System.” Further, TOP-004-2 is proposed to be retired under the work of the Project 2007-03 drafting team. Its requirements will either be deleted or assigned elsewhere.

***TOP-006-1—Monitoring System Conditions (addressed in the NERC Directive; the SDT believes NERC intended to refer to TOP-006-2)***

Only the NERC Directive addresses TOP-006. It states: “TOP-006-1 R3 ensures technical information is provided to the responsible personnel; R6 ensures correct and accurate data to TOP and BA.” But PRC-001-1 R1 (“Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area”) addresses the necessary Generator Operator requirements with respect to TOP-006-2 R3. The SDT believes that knowledge of the purpose and limitations of protection system schemes applied in its area (required in PRC-001-1 R1) constitutes knowledge of “the appropriate technical information concerning protective relays” (required in TOP-006-1 R3).

TOP-006-2 R6 states “Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.” FAC-001-1 R2.1.6 already requires the Transmission Owner’s facility connection requirements to address “metering and telecommunications.” Any generator Facility that interconnected with a Transmission Owner would have had to meet their Facility connection and system performance requirements for metering and telecommunications. Thus, there is no reliability gap.

***TOP-008-1—Response to Transmission Limit Violations (addressed in the Ad Hoc Report)***

Only the Ad Hoc Report addressed TOP-008-1, and it proposed a new requirement, R5, to TOP-008-1—Response to Transmission Limit Violations that would read “The Generator Operator shall disconnect the Generator Interconnection Facility when safety is jeopardized or the overload or abnormal voltage or reactive condition persists and generating equipment or the Generator Interconnection Facility is endangered. In doing so, the Generator Operator shall notify its Transmission Operator and Balancing Authority impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.” The SDT sees no reliability benefit to adding this requirement. TOP-001-1 R7 (“Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless...”) and its parts give the

Generator Operator authority over its Facilities, which would include the generator interconnection Facility. If there is an outage, R7.1 requires the Generator Operator to notify and coordinate with its Transmission Operator, which is required to notify the Reliability Coordinator and other affected Transmission Operators. And as with TOP-004-2, the Project 2007-03 drafting team has proposed to delete all of TOP-008-1's requirements and retiring the standard.

**Conclusion**

The Project 2010-07 SDT is confident that the changes it has proposed address the reliability gap that exists with respect to the responsibilities of Generator Owners and Generator Operations that own sole-use interconnection Facilities. The changes to FAC-001, FAC-003, and PRC-004 have been supported by stakeholders during comment periods, and there has been no strong support of technical justification provided for bringing other standards into the scope of this project.

# Standards Announcement

## Project 2010-07 Generator Requirements at the Transmission Interface

Recirculation Ballot Windows Open April 24, 2012 through May 3, 2012

### [Now Available](#)

Recirculation ballots for two versions of FAC-003—Transmission Vegetation Management Program (FAC-003-X and FAC-003-3) and PRC-005-1.1a – Transmission and Generation Protection System Maintenance and Testing are **open Tuesday, April 24 2012 through 8 p.m. Eastern on Thursday, May 3, 2012.**

### Summary of Changes

The Generator Requirements at the Transmission Interface drafting team has posted FAC-003-X, FAC-003-3, and PRC-005-1.1b (formerly PRC-005-1.1a before PRC-005-1b was approved by FERC on March 14, 2012) for recirculation ballot. The drafting team has made limited changes to these standards:

- **FAC-003-X:**
  - The Applicability section was reformatted to make it clear that the standard applies on a Facility by Facility basis (as in FAC-003-3), not simply to all generator interconnection Facilities owned by a Generator Owner with at least one qualifying generator interconnection Facility.
  - In the Purpose section, Right-of-Way was capitalized because it is an approved NERC glossary term (approved with the initial version of FAC-003) and “North American Electric Reliability Council” was changed to “North American Electric Reliability Corporation.”
  - Regional Entity was added back to the Applicability section of the standard. Requirement R4 is assigned to the Regional Entity, and the Project 2010-07 does not have the authority, based on the scope outlined in its SAR, to modify that requirement. Thus, Regional Entity must remain in the Applicability section.
  - New boilerplate language, recently approved by NERC legal staff, was added to the Effective Dates section of the standard and the Implementation Plan – this did not modify the proposed effective date.
  - *Note that if both FAC-003-X and FAC-003-3 are approved in this recirculation ballot, only FAC-003-3 will be presented to NERC’s Board of Trustees. FAC-003-X has been modified so that the generator interconnection Facility gap can be quickly addressed in the event that neither FAC-003-2 nor FAC-003-3 is approved by FERC.*

- **FAC-003-3:**
  - A typo was found in the Severe VSL for R2; the previous reference to “Transmission Owner” was changed to “responsible entity,” as in all other FAC-003-3 VSLs.
  - New boilerplate language, recently approved by NERC legal staff, was added to the Effective Dates section of the standard and the Implementation Plan – this did not modify the proposed effective date.
- **PRC-005-1.1b:**
  - The standard was updated to version 1.1b.
  - New boilerplate language, recently approved by NERC legal staff, was added to the Effective Dates section of the standard and the Implementation Plan – this did not modify the proposed effective date.

None of these changes are considered significant, as they do not change the scope or applicability of their associated requirements.

Note that more substantive revisions to PRC-005-2 (under Project 2007-17 Protection System Maintenance and Testing) were posted for a parallel 30-day formal comment period and successive ballot through March 28, 2012. The proposed standard received 73.93% approval. The Project 2010-07 SDT recognizes this and supports the work of that team, whose changes eliminate the need for the surgical addition of “generator interconnection Facility” made in PRC-005-1.1b. Because the Project 2010-07 SDT cannot predict the outcome of Project 2007-17 and wants to ensure that generator interconnection Facilities are appropriately addressed in PRC-005 whether or not PRC-005-2 proceeds to NERC's Board this year, it has elected to continue with its revisions to PRC-005-1.1b.

### Instructions

In the recirculation ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their previously cast votes. A ballot pool member who failed to cast a ballot during the last ballot window may cast a ballot in the recirculation ballot window. If a ballot pool member does not participate in the recirculation ballot, that member's vote cast in the previous ballot will be carried over as that member's vote in the recirculation ballot. Members of the ballot pools associated with this project may log in and submit their votes for the standards by clicking [here](#).

### Next Steps

Voting results will be posted and announced after the ballot windows close. If approved, the standard(s) will be submitted to the Board of Trustees for adoption.

### Background

The purpose of Project 2010-07 is to ensure that all generator-owned Facilities are appropriately covered under NERC's Reliability Standards. While many Generator Owners and Generator Operators operate Facilities, commonly known as generator interconnection Facilities that are considered by



some entities to be transmission, these are most often radial Facilities that are not part of the integrated grid. As such, they should not be subject to the same standards applicable to Transmission Owners and Transmission Operators who own and operate Transmission Elements and Facilities that are part of the integrated grid.

As part of the BES, generators do affect the overall reliability of the BES. But registering a Generator Owner or Generator Operator as a Transmission Owner or Transmission Operator, as has been the solution in some cases in the past, may decrease reliability by diverting the Generator Owner's or Generator Operator's resources from the operation of the equipment that actually produces electricity – the generation equipment itself.

The drafting team's goal is to ensure that an adequate level of reliability is maintained in the BES by clearly describing which standards need to be applied to generator interconnection Facilities that are not already applicable to Generator Owners or Generator Operators. The SDT believes that properly applying FAC-003 and PRC-005 to Generator Owners as proposed in the redline standards posted for comment, along with applying FAC-001-1 and PRC-004-2.1a (which were approved by NERC's Board on February 9, 2012), supports this objective.

Before reviewing the standards, the drafting team encourages all stakeholders to read the [technical justification resource document](#) it has provided to describe its rationale and its work thus far.

Additional information is available on the [project page](#).

### **Standards Development Process**

The [Standard Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. For more information or assistance, please contact Monica Benson at [monica.benson@nerc.net](mailto:monica.benson@nerc.net).

*For more information or assistance, please contact Monica Benson,  
Standards Process Administrator, at [monica.benson@nerc.net](mailto:monica.benson@nerc.net) or at 404-446-2560.*

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## Standards Announcement

### Project 2010-07 – Generator Requirements at the Transmission Interface

#### Recirculation Ballot Results

#### [Now Available](#)

Ballots of three standards from Project 2010-07 - Generator Requirements at the Transmission Interface concluded Thursday, May 3, 2012:

Voting statistics for each ballot are listed below, and the [Ballots Results](#) page provides a link to the detailed results.

Standard	Quorum	Approval
FAC-003-3 – Transmission Vegetation Management	Quorum: 81.72%	Approval: 87.34%
FAC-003-X – Transmission Vegetation Management Program	Quorum: 81.94%	Approval: 87.32%
PRC-005-1.1a – Transmission and Generation Protection System Maintenance and Testing	Quorum: 90.44%	Approval: 93.23%

#### Next Steps

FAC-003-3 – Transmission Vegetation Management, FAC-003-X – Transmission Vegetation Management Program, and PRC-005-1.1a – Transmission and Generation Protection System Maintenance and Testing will be presented to the NERC Board of Trustees for adoption and subsequently filed with regulatory authorities.

#### Background

The purpose of Project 2010-07 is to ensure that all generator-owned Facilities are appropriately covered under NERC’s Reliability Standards. While many Generator Owners and Generator Operators operate Facilities, commonly known as generator interconnection Facilities, that are considered by some entities to be transmission, these are most often radial Facilities that are not part of the integrated grid. As such, they should not be subject to the same standards applicable to Transmission

Owners and Transmission Operators who own and operate Transmission Elements and Facilities that are part of the integrated grid.

As part of the BES, generators affect the overall reliability of the BES. But registering a Generator Owner or Generator Operator as a Transmission Owner or Transmission Operator, as has been the solution in some cases in the past, may decrease reliability by diverting the Generator Owner's or Generator Operator's resources from the operation of the equipment that actually produces electricity – the generation equipment itself.

The drafting team's goal is to ensure that an adequate level of reliability is maintained in the BES by clearly describing which standards need to be applied to generator interconnection Facilities that are not already applicable to Generator Owners or Generator Operators.

Additional information is available on the [project page](#).

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Standards Process Administrator, at [monica.benson@nerc.net](mailto:monica.benson@nerc.net) or at 404-446-2560.*

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Ballot Results	
<b>Ballot Name:</b>	Project 2010-07 Recirculation Ballot FAC-003-3
<b>Ballot Period:</b>	4/24/2012 - 5/3/2012
<b>Ballot Type:</b>	Recirculation
<b>Total # Votes:</b>	313
<b>Total Ballot Pool:</b>	383
<b>Quorum:</b>	<b>81.72 % The Quorum has been reached</b>
<b>Weighted Segment Vote:</b>	87.34 %
<b>Ballot Results:</b>	<b>The Standard has Passed.</b>

Summary of Ballot Results									
Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain # Votes	No Vote	
			# Votes	Fraction	# Votes	Fraction			
1 - Segment 1.	96	1	56	0.889	7	0.111	14	19	
2 - Segment 2.	9	0.8	7	0.7	1	0.1	0	1	
3 - Segment 3.	80	1	48	0.857	8	0.143	12	12	
4 - Segment 4.	31	1	23	0.885	3	0.115	2	3	
5 - Segment 5.	94	1	56	0.875	8	0.125	9	21	
6 - Segment 6.	51	1	34	0.895	4	0.105	7	6	
7 - Segment 7.	1	0	0	0	0	0	0	1	
8 - Segment 8.	7	0.5	5	0.5	0	0	1	1	
9 - Segment 9.	5	0.1	1	0.1	0	0	0	4	
10 - Segment 10.	9	0.7	5	0.5	2	0.2	0	2	
<b>Totals</b>	<b>383</b>	<b>7.1</b>	<b>235</b>	<b>6.201</b>	<b>33</b>	<b>0.899</b>	<b>45</b>	<b>70</b>	

Individual Ballot Pool Results				
Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	<a href="#">View</a>
1	American Electric Power	Paul B. Johnson	Affirmative	<a href="#">View</a>
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman		
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Gregory S Miller		

1	BC Hydro and Power Authority	Patricia Robertson	Negative	<a href="#">View</a>
1	Beaches Energy Services	Joseph S Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Abstain	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	George S. Carruba		
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Abstain	
1	Georgia Transmission Corporation	Harold Taylor	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt	Affirmative	<a href="#">View</a>
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	<a href="#">View</a>
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Negative	<a href="#">View</a>
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney	Abstain	
1	Northeast Utilities	David Boguslawski		
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Matthey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Brett A Koelsch		
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	

1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	Santee Cooper	Terry L Blackwell	Abstain	
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Sierra Pacific Power Co.	Rich Salgo		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	<a href="#">View</a>
1	Southern Illinois Power Coop.	William Hutchison	Abstain	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Vermont Electric Power Company, Inc.	Kim Moulton		
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	<a href="#">View</a>
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E DeLoach	Affirmative	<a href="#">View</a>
3	Alabama Power Company	Richard J. Mandes	Negative	<a href="#">View</a>
3	Ameren Services	Mark Peters	Negative	
3	Anaheim Public Utilities Dept.	Kelly Nguyen		
3	APS	Steven Norris	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	<a href="#">View</a>
3	City of Alexandria	Michael Marcotte	Negative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	<a href="#">View</a>
3	City of Green Cove Springs	Gregg R Griffin	Abstain	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Roseville	Susan E Gill-Zobitz		
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Affirmative	<a href="#">View</a>
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy	Richard Blumenstock	Abstain	
3	Cowlitz County PUD	Russell A Noble	Negative	<a href="#">View</a>
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	<a href="#">View</a>
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Negative	<a href="#">View</a>
3	Georgia Systems Operations Corporation	William N. Phinney	Affirmative	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen		

3	Gulf Power Company	Paul C Caldwell	Negative	<a href="#">View</a>
3	Harney Electric Cooperative, Inc.	Shane Sweet	Abstain	
3	Holland Board of Public Works	William Bush	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent	Negative	<a href="#">View</a>
3	Mississippi Power	Jeff Franklin	Negative	<a href="#">View</a>
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	<a href="#">View</a>
3	Nebraska Public Power District	Tony Eddleman	Affirmative	<a href="#">View</a>
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	NRG Energy Power Marketing, Inc.	Rick Keetch	Abstain	
3	Ocala Electric Utility	David Anderson		
3	Orange and Rockland Utilities, Inc.	David Burke	Abstain	
3	Oregon Trail Electric Cooperative	ned ratterman		
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	<a href="#">View</a>
3	PacifiCorp	Dan Zollner	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Abstain	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alabama Municipal Electric Authority	Raymond Phillips	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Clewiston	Kevin McCarthy	Affirmative	<a href="#">View</a>
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Abstain	
4	Cowlitz County PUD	Rick Syring	Negative	<a href="#">View</a>
4	Detroit Edison Company	Daniel Herring		
4	Flathead Electric Cooperative	Russ Schneider	Negative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	<a href="#">View</a>
4	Fort Pierce Utilities Authority	Thomas Richards		
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Imperial Irrigation District	Diana U Torres	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Affirmative	
4	Integrus Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Affirmative	
4	North Carolina Electric Membership Corp.	Bob Beadle	Affirmative	



4	Northern California Power Agency	Tracy R Bibb	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	<a href="#">View</a>
5	AEP Service Corp.	Brock Ondayko		
5	AES Corporation	Leo Bernier	Affirmative	
5	Amerenue	Sam Dwyer	Negative	
5	American Wind Energy Association	Natalie McIntire	Affirmative	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar		
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Bayer	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	<a href="#">View</a>
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick		
5	City of Tallahassee	Brian Horton		
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy, Inc.	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Abstain	
5	Cowlitz County PUD	Bob Essex	Negative	<a href="#">View</a>
5	CPS Energy	Robert Stevens		
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Negative	<a href="#">View</a>
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	East Kentucky Power Coop.	Stephen Ricker		
5	Electric Power Supply Association	John R Cashin	Affirmative	
5	Energy Northwest - Columbia Generating Station	James Sauceda		
5	Entegra Power Group, LLC	Kenneth B Parker	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	<a href="#">View</a>
5	Great River Energy	Preston L Walsh	Affirmative	<a href="#">View</a>
5	Green Country Energy	Greg Froehling		
5	Imperial Irrigation District	Marcela Y Caballero	Affirmative	
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	Infigen Energy US	Pamela C Zdenek		
5	Invenergy LLC	Alan Beckham	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	<a href="#">View</a>
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman	Affirmative	

5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	Manitoba Hydro	S N Fernando	Negative	<a href="#">View</a>
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	<a href="#">View</a>
5	Nebraska Public Power District	Don Schmit	Affirmative	<a href="#">View</a>
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern California Power Agency	Hari Modi	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson		
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oklahoma Gas and Electric Co.	Kim Morphis		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	Colin Anderson	Abstain	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Gary L Tingley		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Fossil LLC	Mikhail Falkovich	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Abstain	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	RES Americas Inc	Ravi Bantu		
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	<a href="#">View</a>
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	ACES Power Marketing	Jason L Marshall	Abstain	
6	AEP Marketing	Edward P. Cox	Affirmative	<a href="#">View</a>
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	RANDY A YOUNG	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirschak	Affirmative	
6	Colorado Springs Utilities	Lisa C Rosintoski		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Abstain	
6	Constellation Energy Commodities Group	Brenda L Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Energy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	<a href="#">View</a>
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	<a href="#">View</a>
6	Florida Municipal Power Pool	Thomas Washburn	Abstain	
6	Florida Power & Light Co.	Silvia P. Mitchell	Negative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	



6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	<a href="#">View</a>
6	MidAmerican Energy Co.	Dennis Kimm	Affirmative	
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	
6	South California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	<a href="#">View</a>
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner	Abstain	
8		Edward C Stein	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini		
8	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
8	Volkman Consulting, Inc.	Terry Volkman	Affirmative	
9	California Energy Commission	William M Chamberlain		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Affirmative	
9	New York State Department of Public Service	Thomas Dvorsky		
9	Public Utilities Commission of Ohio	Klaus Lambeck		
10	Florida Reliability Coordinating Council	Linda Campbell		
10	Midwest Reliability Organization	James D Burley	Affirmative	<a href="#">View</a>
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Negative	<a href="#">View</a>
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	
10	Western Electricity Coordinating Council	Steven L. Rueckert		

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Ballot Results	
<b>Ballot Name:</b>	Project 2010-07 Recirculation Ballot FAC-003-x
<b>Ballot Period:</b>	4/24/2012 - 5/3/2012
<b>Ballot Type:</b>	Recirculation
<b>Total # Votes:</b>	313
<b>Total Ballot Pool:</b>	382
<b>Quorum:</b>	<b>81.94 % The Quorum has been reached</b>
<b>Weighted Segment Vote:</b>	87.32 %
<b>Ballot Results:</b>	<b>The Standard has Passed.</b>

Summary of Ballot Results									
Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain # Votes	No Vote	
			# Votes	Fraction	# Votes	Fraction			
1 - Segment 1.	95	1	56	0.903	6	0.097	15	18	
2 - Segment 2.	9	0.8	8	0.8	0	0	0	1	
3 - Segment 3.	80	1	48	0.857	8	0.143	13	11	
4 - Segment 4.	31	1	21	0.875	3	0.125	3	4	
5 - Segment 5.	94	1	55	0.873	8	0.127	10	21	
6 - Segment 6.	51	1	33	0.892	4	0.108	8	6	
7 - Segment 7.	1	0	0	0	0	0	0	1	
8 - Segment 8.	7	0.5	4	0.4	1	0.1	1	1	
9 - Segment 9.	5	0.1	1	0.1	0	0	0	4	
10 - Segment 10.	9	0.7	5	0.5	2	0.2	0	2	
<b>Totals</b>	<b>382</b>	<b>7.1</b>	<b>231</b>	<b>6.2</b>	<b>32</b>	<b>0.9</b>	<b>50</b>	<b>69</b>	

Individual Ballot Pool Results				
Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	<a href="#">View</a>
1	American Electric Power	Paul B. Johnson	Affirmative	<a href="#">View</a>
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman		
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	

1	Beaches Energy Services	Joseph S Stonecipher	Affirmative	<a href="#">View</a>
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Abstain	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	George S. Carruba		
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Abstain	
1	Georgia Transmission Corporation	Harold Taylor	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt	Affirmative	<a href="#">View</a>
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	<a href="#">View</a>
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Negative	<a href="#">View</a>
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney	Abstain	
1	Northeast Utilities	David Boguslawski		
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Matthey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Brett A Koelsch		
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	

1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	Santee Cooper	Terry L Blackwell	Abstain	
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Sierra Pacific Power Co.	Rich Salgo		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	<a href="#">View</a>
1	Southern Illinois Power Coop.	William Hutchison	Abstain	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Vermont Electric Power Company, Inc.	Kim Moulton		
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	<a href="#">View</a>
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	<a href="#">View</a>
3	Alabama Power Company	Richard J. Mandes	Negative	<a href="#">View</a>
3	Ameren Services	Mark Peters	Negative	
3	Anaheim Public Utilities Dept.	Kelly Nguyen		
3	APS	Steven Norris	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	<a href="#">View</a>
3	City of Alexandria	Michael Marcotte	Negative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	<a href="#">View</a>
3	City of Clewiston	Lynne Mila	Affirmative	<a href="#">View</a>
3	City of Green Cove Springs	Gregg R Griffin	Abstain	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Roseville	Susan E Gill-Zobitz		
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Affirmative	<a href="#">View</a>
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy	Richard Blumenstock	Abstain	
3	Cowlitz County PUD	Russell A Noble	Negative	<a href="#">View</a>
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Energy Delivery	Stephan Kern	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	<a href="#">View</a>
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Negative	<a href="#">View</a>
3	Georgia Systems Operations Corporation	William N. Phinney	Affirmative	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen		
3	Gulf Power Company	Paul C Caldwell	Negative	<a href="#">View</a>

3	Harney Electric Cooperative, Inc.	Shane Sweet	<a href="#">Abstain</a>	
3	Holland Board of Public Works	William Bush	<a href="#">Affirmative</a>	
3	Hydro One Networks, Inc.	David Kiguel	<a href="#">Affirmative</a>	
3	Imperial Irrigation District	Jesus S. Alcaraz	<a href="#">Affirmative</a>	
3	JEA	Garry Baker	<a href="#">Affirmative</a>	
3	Kansas City Power & Light Co.	Charles Locke	<a href="#">Affirmative</a>	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik	<a href="#">Abstain</a>	
3	Louisville Gas and Electric Co.	Charles A. Freibert	<a href="#">Affirmative</a>	
3	Manitoba Hydro	Greg C. Parent	<a href="#">Negative</a>	<a href="#">View</a>
3	Mississippi Power	Jeff Franklin	<a href="#">Negative</a>	<a href="#">View</a>
3	Municipal Electric Authority of Georgia	Steven M. Jackson	<a href="#">Affirmative</a>	
3	Muscatine Power & Water	John S Bos	<a href="#">Affirmative</a>	<a href="#">View</a>
3	Nebraska Public Power District	Tony Eddleman	<a href="#">Affirmative</a>	<a href="#">View</a>
3	New York Power Authority	Marilyn Brown	<a href="#">Affirmative</a>	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	<a href="#">Affirmative</a>	
3	Northern Indiana Public Service Co.	William SeDoris	<a href="#">Affirmative</a>	
3	NRG Energy Power Marketing, Inc.	Rick Keetch	<a href="#">Abstain</a>	
3	Ocala Electric Utility	David Anderson		
3	Orange and Rockland Utilities, Inc.	David Burke	<a href="#">Abstain</a>	
3	Oregon Trail Electric Cooperative	ned ratterman		
3	Orlando Utilities Commission	Ballard K Mutters	<a href="#">Affirmative</a>	
3	Owensboro Municipal Utilities	Thomas T Lyons	<a href="#">Affirmative</a>	
3	Pacific Gas and Electric Company	John H Hagen	<a href="#">Affirmative</a>	
3	PacifiCorp	Dan Zollner	<a href="#">Affirmative</a>	
3	Platte River Power Authority	Terry L Baker	<a href="#">Affirmative</a>	
3	PNM Resources	Michael Mertz	<a href="#">Affirmative</a>	
3	Potomac Electric Power Co.	Robert Reuter	<a href="#">Abstain</a>	
3	Progress Energy Carolinas	Sam Waters	<a href="#">Affirmative</a>	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	<a href="#">Affirmative</a>	
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	<a href="#">Affirmative</a>	
3	Sacramento Municipal Utility District	James Leigh-Kendall	<a href="#">Affirmative</a>	
3	Salt River Project	John T. Underhill	<a href="#">Affirmative</a>	
3	Santee Cooper	James M Poston	<a href="#">Abstain</a>	
3	Seattle City Light	Dana Wheelock	<a href="#">Affirmative</a>	
3	Seminole Electric Cooperative, Inc.	James R Frauen	<a href="#">Affirmative</a>	
3	Snohomish County PUD No. 1	Mark Oens	<a href="#">Affirmative</a>	
3	South Carolina Electric & Gas Co.	Hubert C Young	<a href="#">Abstain</a>	
3	Tacoma Public Utilities	Travis Metcalfe	<a href="#">Affirmative</a>	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	<a href="#">Affirmative</a>	
3	Tri-State G & T Association, Inc.	Janelle Marriott	<a href="#">Affirmative</a>	
3	Westar Energy	Bo Jones	<a href="#">Affirmative</a>	
3	Wisconsin Electric Power Marketing	James R Keller	<a href="#">Affirmative</a>	
3	Xcel Energy, Inc.	Michael Ibold	<a href="#">Affirmative</a>	<a href="#">View</a>
4	Alabama Municipal Electric Authority	Raymond Phillips	<a href="#">Affirmative</a>	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	<a href="#">Affirmative</a>	
4	American Municipal Power	Kevin Koloini	<a href="#">Affirmative</a>	
4	Blue Ridge Power Agency	Duane S Dahlquist	<a href="#">Affirmative</a>	
4	City of Clewiston	Kevin McCarthy	<a href="#">Affirmative</a>	<a href="#">View</a>
4	City of Redding	Nicholas Zettel	<a href="#">Affirmative</a>	
4	City Utilities of Springfield, Missouri	John Allen	<a href="#">Affirmative</a>	
4	Consumers Energy	David Frank Ronk	<a href="#">Abstain</a>	
4	Cowlitz County PUD	Rick Syring	<a href="#">Negative</a>	<a href="#">View</a>
4	Detroit Edison Company	Daniel Herring		
4	Flathead Electric Cooperative	Russ Schneider	<a href="#">Negative</a>	
4	Florida Municipal Power Agency	Frank Gaffney	<a href="#">Affirmative</a>	<a href="#">View</a>
4	Fort Pierce Utilities Authority	Thomas Richards		
4	Georgia System Operations Corporation	Guy Andrews	<a href="#">Affirmative</a>	
4	Imperial Irrigation District	Diana U Torres	<a href="#">Affirmative</a>	
4	Indiana Municipal Power Agency	Jack Alvey	<a href="#">Affirmative</a>	<a href="#">View</a>
4	Integrus Energy Group, Inc.	Christopher Plante	<a href="#">Abstain</a>	
4	Madison Gas and Electric Co.	Joseph DePoorter	<a href="#">Affirmative</a>	
4	Modesto Irrigation District	Spencer Tacke		
4	North Carolina Electric Membership Corp.	Bob Beadle	<a href="#">Affirmative</a>	
4	Northern California Power Agency	Tracy R Bibb	<a href="#">Affirmative</a>	

4	Ohio Edison Company	Douglas Hohlbaugh	<a href="#">Abstain</a>	
4	Old Dominion Electric Coop.	Mark Ringhausen	<a href="#">Affirmative</a>	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	<a href="#">Affirmative</a>	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	<a href="#">Affirmative</a>	
4	Sacramento Municipal Utility District	Mike Ramirez	<a href="#">Affirmative</a>	
4	Seattle City Light	Hao Li	<a href="#">Affirmative</a>	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	<a href="#">Affirmative</a>	
4	South Mississippi Electric Power Association	Steven McElhanev		
4	Tacoma Public Utilities	Keith Morissette	<a href="#">Affirmative</a>	
4	Wisconsin Energy Corp.	Anthony Jankowski	<a href="#">Negative</a>	<a href="#">View</a>
5	AEP Service Corp.	Brock Ondayko		
5	AES Corporation	Leo Bernier	<a href="#">Affirmative</a>	
5	Amerenue	Sam Dwyer	<a href="#">Negative</a>	
5	American Wind Energy Association	Natalie McIntire	<a href="#">Affirmative</a>	
5	Arizona Public Service Co.	Edward Cambridge	<a href="#">Affirmative</a>	
5	Avista Corp.	Edward F. Groce	<a href="#">Affirmative</a>	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar		
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	<a href="#">Affirmative</a>	
5	Bonneville Power Administration	Francis J. Halpin	<a href="#">Affirmative</a>	
5	BP Wind Energy North America Inc	Carla Bayer	<a href="#">Affirmative</a>	
5	BrightSource Energy, Inc.	Chifong Thomas	<a href="#">Affirmative</a>	<a href="#">View</a>
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	<a href="#">Affirmative</a>	
5	City of Redding	Paul Cummings	<a href="#">Affirmative</a>	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick		
5	City of Tallahassee	Brian Horton		
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy, Inc.	Mike D Hirst	<a href="#">Affirmative</a>	
5	Colorado Springs Utilities	Jennifer Eckels	<a href="#">Affirmative</a>	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	<a href="#">Abstain</a>	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	<a href="#">Abstain</a>	
5	Consumers Energy Company	David C Greyerbiehl	<a href="#">Abstain</a>	
5	Cowlitz County PUD	Bob Essex	<a href="#">Negative</a>	<a href="#">View</a>
5	CPS Energy	Robert Stevens		
5	Detroit Edison Company	Christy Wicke	<a href="#">Affirmative</a>	
5	Dominion Resources, Inc.	Mike Garton	<a href="#">Affirmative</a>	
5	Duke Energy	Dale Q Goodwine	<a href="#">Affirmative</a>	
5	Dynegy Inc.	Dan Roethemeyer	<a href="#">Negative</a>	<a href="#">View</a>
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	<a href="#">Abstain</a>	
5	East Kentucky Power Coop.	Stephen Ricker		
5	Electric Power Supply Association	John R Cashin	<a href="#">Affirmative</a>	
5	Energy Northwest - Columbia Generating Station	James Saucedo		
5	Entegra Power Group, LLC	Kenneth B Parker	<a href="#">Abstain</a>	
5	Exelon Nuclear	Michael Korchynsky	<a href="#">Affirmative</a>	<a href="#">View</a>
5	ExxonMobil Research and Engineering	Martin Kaufman	<a href="#">Negative</a>	
5	FirstEnergy Solutions	Kenneth Dresner	<a href="#">Abstain</a>	
5	Florida Municipal Power Agency	David Schumann	<a href="#">Affirmative</a>	<a href="#">View</a>
5	Great River Energy	Preston L Walsh	<a href="#">Affirmative</a>	<a href="#">View</a>
5	Green Country Energy	Greg Froehling		
5	Imperial Irrigation District	Marcela Y Caballero	<a href="#">Affirmative</a>	
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	Infigen Energy US	Pamela C Zdenek		
5	Invenergy LLC	Alan Beckham	<a href="#">Affirmative</a>	
5	JEA	John J Babik	<a href="#">Affirmative</a>	
5	Kissimmee Utility Authority	Mike Blough	<a href="#">Affirmative</a>	
5	Lakeland Electric	James M Howard	<a href="#">Affirmative</a>	<a href="#">View</a>
5	Liberty Electric Power LLC	Daniel Duff	<a href="#">Negative</a>	
5	Lincoln Electric System	Dennis Florom	<a href="#">Abstain</a>	
5	Los Angeles Department of Water & Power	Kenneth Silver	<a href="#">Affirmative</a>	
5	Lower Colorado River Authority	Tom Foreman	<a href="#">Affirmative</a>	
5	Luminant Generation Company LLC	Mike Laney	<a href="#">Affirmative</a>	



5	Manitoba Hydro	S N Fernando	Negative	<a href="#">View</a>
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	<a href="#">View</a>
5	Nebraska Public Power District	Don Schmit	Affirmative	<a href="#">View</a>
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern California Power Agency	Hari Modi	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson		
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oklahoma Gas and Electric Co.	Kim Morphis		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	Colin Anderson	Abstain	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Gary L Tingley		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Fossil LLC	Mikhail Falkovich	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Abstain	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	RES Americas Inc	Ravi Bantu		
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	<a href="#">View</a>
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	ACES Power Marketing	Jason L Marshall	Abstain	
6	AEP Marketing	Edward P. Cox	Affirmative	<a href="#">View</a>
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	RANDY A YOUNG	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirschak	Affirmative	
6	Colorado Springs Utilities	Lisa C Rosintoski		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Abstain	
6	Constellation Energy Commodities Group	Brenda L Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	<a href="#">View</a>
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	<a href="#">View</a>
6	Florida Municipal Power Pool	Thomas Washburn	Abstain	
6	Florida Power & Light Co.	Silvia P. Mitchell	Negative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Luminant Energy	Brad Jones	Affirmative	



6	Manitoba Hydro	Daniel Prowse	Negative	<a href="#">View</a>
6	MidAmerican Energy Co.	Dennis Kimm	Affirmative	
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	
6	South California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	<a href="#">View</a>
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		James A Maenner	Abstain	
8		Edward C Stein	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini		
8	Utility Services, Inc.	Brian Evans-Mongeon	Negative	<a href="#">View</a>
8	Volkman Consulting, Inc.	Terry Volkman	Affirmative	
9	California Energy Commission	William M Chamberlain		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Affirmative	
9	New York State Department of Public Service	Thomas Dvorsky		
9	Public Utilities Commission of Ohio	Klaus Lambeck		
10	Florida Reliability Coordinating Council	Linda Campbell		
10	Midwest Reliability Organization	James D Burley	Affirmative	<a href="#">View</a>
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Negative	<a href="#">View</a>
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	
10	Western Electricity Coordinating Council	Steven L. Rueckert		

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Ballot Results	
<b>Ballot Name:</b>	Project 2010-07 PRC-005-1.1a
<b>Ballot Period:</b>	4/24/2012 - 5/3/2012
<b>Ballot Type:</b>	recirculation
<b>Total # Votes:</b>	350
<b>Total Ballot Pool:</b>	387
<b>Quorum:</b>	<b>90.44 % The Quorum has been reached</b>
<b>Weighted Segment Vote:</b>	93.23 %
<b>Ballot Results:</b>	<b>The Standard has Passed</b>

Summary of Ballot Results									
Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain # Votes	No Vote	
			# Votes	Fraction	# Votes	Fraction			
1 - Segment 1.	102	1	72	0.9	8	0.1	9	13	
2 - Segment 2.	8	0.5	5	0.5	0	0	2	1	
3 - Segment 3.	84	1	65	0.915	6	0.085	8	5	
4 - Segment 4.	28	1	23	0.958	1	0.042	3	1	
5 - Segment 5.	96	1	69	0.896	8	0.104	8	11	
6 - Segment 6.	51	1	34	0.85	6	0.15	6	5	
7 - Segment 7.	0	0	0	0	0	0	0	0	
8 - Segment 8.	7	0.6	6	0.6	0	0	1	0	
9 - Segment 9.	3	0.2	2	0.2	0	0	0	1	
10 - Segment 10.	8	0.8	8	0.8	0	0	0	0	
<b>Totals</b>	<b>387</b>	<b>7.1</b>	<b>284</b>	<b>6.619</b>	<b>29</b>	<b>0.481</b>	<b>37</b>	<b>37</b>	

Individual Ballot Pool Results				
Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	<a href="#">View</a>
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Negative	<a href="#">View</a>
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	

1	Baltimore Gas & Electric Company	Gregory S Miller	<a href="#">Abstain</a>	<a href="#">View</a>
1	BC Hydro and Power Authority	Patricia Robertson	<a href="#">Affirmative</a>	
1	Beaches Energy Services	Joseph S Stonecipher	<a href="#">Affirmative</a>	<a href="#">View</a>
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	<a href="#">Negative</a>	<a href="#">View</a>
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	<a href="#">Affirmative</a>	<a href="#">View</a>
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	<a href="#">Affirmative</a>	
1	Central Electric Power Cooperative	Michael B Bax	<a href="#">Affirmative</a>	<a href="#">View</a>
1	Central Maine Power Company	Joseph Turano Jr.	<a href="#">Affirmative</a>	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	<a href="#">Affirmative</a>	
1	Clark Public Utilities	Jack Stamper	<a href="#">Affirmative</a>	
1	Colorado Springs Utilities	Paul Morland	<a href="#">Affirmative</a>	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	<a href="#">Affirmative</a>	
1	CPS Energy	Richard Castrejana	<a href="#">Affirmative</a>	
1	Dairyland Power Coop.	Robert W. Roddy	<a href="#">Affirmative</a>	
1	Dayton Power & Light Co.	Hertzel Shamash	<a href="#">Affirmative</a>	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	<a href="#">Affirmative</a>	
1	Duke Energy Carolina	Douglas E. Hils		
1	Empire District Electric Co.	Ralph F Meyer	<a href="#">Affirmative</a>	
1	Entergy Services, Inc.	Edward J Davis	<a href="#">Affirmative</a>	
1	FirstEnergy Corp.	William J Smith	<a href="#">Affirmative</a>	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	<a href="#">Affirmative</a>	
1	Florida Power & Light Co.	Mike O'Neil	<a href="#">Affirmative</a>	
1	FortisBC	Curtis Klashinsky		
1	Georgia Transmission Corporation	Jason Snodgrass	<a href="#">Affirmative</a>	
1	Great River Energy	Gordon Pietsch	<a href="#">Affirmative</a>	<a href="#">View</a>
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	<a href="#">Affirmative</a>	
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Ronald D. Schellberg	<a href="#">Affirmative</a>	
1	Imperial Irrigation District	Tino Zaragoza	<a href="#">Affirmative</a>	
1	International Transmission Company Holdings Corp	Michael Moltane	<a href="#">Abstain</a>	
1	JEA	Ted Hobson	<a href="#">Affirmative</a>	
1	KAMO Electric Cooperative	Walter Kenyon	<a href="#">Affirmative</a>	
1	Kansas City Power & Light Co.	Michael Gammon	<a href="#">Negative</a>	<a href="#">View</a>
1	Lakeland Electric	Larry E Watt	<a href="#">Affirmative</a>	
1	Lee County Electric Cooperative	John W Delucca	<a href="#">Negative</a>	
1	Lincoln Electric System	Doug Bantam	<a href="#">Abstain</a>	
1	Long Island Power Authority	Robert Ganley	<a href="#">Abstain</a>	
1	Los Angeles Department of Water & Power	John Burnett	<a href="#">Affirmative</a>	
1	Lower Colorado River Authority	Martyn Turner	<a href="#">Affirmative</a>	
1	Manitoba Hydro	Joe D Petaski	<a href="#">Negative</a>	<a href="#">View</a>
1	MEAG Power	Danny Dees	<a href="#">Affirmative</a>	
1	Metropolitan Water District of Southern California	Ernest Hahn	<a href="#">Abstain</a>	
1	MidAmerican Energy Co.	Terry Harbour	<a href="#">Affirmative</a>	
1	Minnkota Power Coop. Inc.	Theresa Allard		
1	Muscatine Power & Water	Tim Reed		
1	Nebraska Public Power District	Cole C Brodine	<a href="#">Affirmative</a>	
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	<a href="#">Affirmative</a>	
1	Northeast Missouri Electric Power Cooperative	Kevin White	<a href="#">Affirmative</a>	
1	Northeast Utilities	David Boguslawski		
1	Northern Indiana Public Service Co.	Kevin M Largura	<a href="#">Affirmative</a>	
1	Ohio Valley Electric Corp.	Robert Matthey	<a href="#">Affirmative</a>	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	<a href="#">Abstain</a>	
1	Omaha Public Power District	Doug Peterchuck	<a href="#">Affirmative</a>	
1	Oncor Electric Delivery	Jen Fiegel	<a href="#">Affirmative</a>	
1	Orlando Utilities Commission	Brad Chase	<a href="#">Abstain</a>	
1	Otter Tail Power Company	Daryl Hanson		
1	PacifiCorp	Ryan Millard	<a href="#">Affirmative</a>	
1	PECO Energy	Ronald Schloendorn	<a href="#">Affirmative</a>	
1	Platte River Power Authority	John C. Collins	<a href="#">Affirmative</a>	

1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Brett A Koelsch	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunkel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	<a href="#">View</a>
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	<a href="#">View</a>
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	<a href="#">View</a>
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Negative	<a href="#">View</a>
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock		
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	<a href="#">View</a>
2	Alberta Electric System Operator	Mark B Thompson	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Abstain	
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	<a href="#">View</a>
3	Alabama Power Company	Richard J. Mandes	Affirmative	<a href="#">View</a>
3	Ameren Services	Mark Peters	Affirmative	
3	APS	Steven Norris	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	<a href="#">View</a>
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	<a href="#">View</a>
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City of Redding	Bill Hughes	Abstain	
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	Entergy	Joel T Plessinger	Affirmative	

3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Flathead Electric Cooperative	John M Goroski	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Danny Lindsey	Affirmative	<a href="#">View</a>
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	<a href="#">View</a>
3	Gulf Power Company	Paul C Caldwell	Affirmative	<a href="#">View</a>
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz	Affirmative	
3	JEA	Garry Baker		
3	Kansas City Power & Light Co.	Charles Locke	Negative	<a href="#">View</a>
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Norman D Harryhill	Affirmative	
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Daniel D Kurowski		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Negative	<a href="#">View</a>
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Affirmative	<a href="#">View</a>
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Ocala Electric Utility	David Anderson	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	<a href="#">View</a>
3	PacifiCorp	Dan Zollner	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter		
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Benton County	Gloria Bender	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	<a href="#">View</a>
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Abstain	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Negative	<a href="#">View</a>
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Negative	<a href="#">View</a>
4	City of Clewiston	Kevin McCarthy	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Abstain	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	

4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Imperial Irrigation District	Diana U Torres	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Affirmative	
4	LaGen	Richard Comeaux	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Affirmative	
4	North Carolina Eastern Municipal Power Agency	Cecil Rhodes	Affirmative	
4	Northern California Power Agency	Tracy R Bibb	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	Tacoma Public Utilities	Keith Morissette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	<a href="#">View</a>
5	AES Corporation	Leo Bernier	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Abstain	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	<a href="#">View</a>
5	BP Wind Energy North America Inc	Carla Bayer	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Abstain	<a href="#">View</a>
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	Castleton Energy Center	John Walsh		
5	City and County of San Francisco	Daniel Mason	Negative	<a href="#">View</a>
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	<a href="#">View</a>
5	City of Redding	Paul Cummings	Abstain	
5	Cogentrix Energy, Inc.	Mike D Hirst		
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea	Affirmative	<a href="#">View</a>
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine		
5	Dynergy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Affirmative	
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer	Affirmative	
5	Electric Power Supply Association	John R Cashin	Affirmative	
5	Energy Services, Inc.	Tracey Stubbs	Affirmative	
5	Essential Power, LLC	Patrick Brown	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	First Solar, Inc.	Robert Jenkins		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	GenOn Energy, Inc	James W Mason	Abstain	
5	Great River Energy	Preston L Walsh	Affirmative	<a href="#">View</a>
5	ICF International	Brent B Hebert	Affirmative	
5	Imperial Irrigation District	Marcela Y Caballero	Affirmative	
5	Invenergy LLC	Alan Beckham	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	<a href="#">View</a>



5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom		
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	Manitoba Hydro	S N Fernando	Negative	<a href="#">View</a>
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern California Power Agency	Hari Modi	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson		
5	Occidental Chemical	Michelle R DAntuono	Affirmative	<a href="#">View</a>
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	<a href="#">View</a>
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Gary L Tingley	Abstain	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	Proven Compliance Solutions	Mitchell E Needham	Abstain	
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 1 of Lewis County	Steven Grega	Abstain	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Claire Lloyd	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	TransAlta Corporation	Rebekka McFadden		
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Negative	<a href="#">View</a>
6	AEP Marketing	Edward P. Cox	Affirmative	<a href="#">View</a>
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	RANDY A YOUNG	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	City of Austin dba Austin Energy	Lisa L Martin	Negative	<a href="#">View</a>
6	City of Redding	Marvin Briggs	Abstain	
6	Cleco Power LLC	Robert Hirschak	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Donald Schopp	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	



6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	<a href="#">View</a>
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	<a href="#">View</a>
6	Lakeland Electric	Paul Shippis	Abstain	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	<a href="#">View</a>
6	MidAmerican Energy Co.	Dennis Kimm	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	<a href="#">View</a>
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach		
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	<a href="#">View</a>
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	
6	South California Edison Company	Ljuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	<a href="#">View</a>
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tenaska Power Services Co.	John D Varnell		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	David F. Lemmons	Negative	<a href="#">View</a>
8		Brendan Kirby	Abstain	
8		James A Maenner	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
8	Volkman Consulting, Inc.	Terry Volkman	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Affirmative	
9	New York State Department of Public Service	Thomas Dvorsky		
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	



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Washington Office: 1120 G Street, N.W. : Suite 990 : Washington, DC 20005-3801

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**Exhibit H**

**Standard Drafting Team Roster for NERC Standards Development Project 2010-07**

**Drafting Team Roster**  
**Project 2010-07 Generator Requirements at the Transmission Interface**

Name and Title	Company and Address	Contact Info	Bio
<p>Louis Slade, Jr., Chair, Senior Electric Market Policy Manager, Electric Market Policy &amp; NERC Compliance</p>	<p>Dominion 5000 Dominion Blvd. Glen Allen, VA 23060</p>	<p>(804) 819-2871 louis.slade@do m.com</p>	<p>Louis Slade spent the first seven years of his career in distribution construction and operations before transferring to system operations. As a system operator, he performed Balancing Authority and Transmission Operations functions. Slade held this position for four years and was then promoted to Supervisor of System Operations. In this role, which he held for 11 years, he oversaw the Balancing Authority and Transmission Operations functions and performed Reliability Coordination functions. Slade was then charged with developing and managing Dominion's Transmission Service Provider function, where he remained for two years before becoming Chief System Operator, responsible for managing staffs that performed Balancing Authority, Reliability Coordination, Transmission Operations, and Transmission Service Provider functions, a position he held for five years.</p> <p>Slade was then promoted to Project Manager and was responsible for the integration of Dominion Va. Power's generation assets into the PJM RTO. Upon PJM integration, he became Manager of the Market Operations Center, which dispatches Dominion Va. Power's generation per PJM RTO rules and interfaces with PJM's operations and markets staffs. Slade held this position for five years and then became the Senior electric Market Police Manager, a services organization position where he represents Dominion at NERC, PJM, RFC, and SERC.</p>
<p>Samuel J. Dwyer, IV, Consulting Engineer, Quality Management Services, Regulatory Compliance</p>	<p>AmerenUE Power Operations Services 1901 Chouteau Ave. St. Louis, MO 63103</p>	<p>(314) 554-4853 SDwyerIV@am eren.com</p>	<p>Samuel J. Dwyer, IV is a Consulting Engineer in the Ameren Missouri affiliate of Ameren Corporation. Ameren Missouri is a regulated, vertically integrated electric and gas utility that owns more than 10,000 MW of generation. This generation includes coal, nuclear, conventional hydro, hydro pumped-storage and gas-fired technologies. Ameren Missouri is a member of MISO and its regional NERC regulatory agency is SERC.</p> <p>Dwyer has worked in the electric industry for over 35 years. His work has included transmission planning, real-time generation operations, real-time transmission operations, interconnection planning and negotiations and generator interconnections. His current responsibilities are focused on NERC Standard compliance for Ameren Missouri as a generator owner. Dwyer has received a Bachelor and Master of Science in electrical engineering from the University of Missouri – Columbia. He has also earned a Master of Business Administration degree from the University of Missouri – St. Louis. Mr. Dwyer is currently a registered Professional Engineer in the state of Missouri.</p>

**Drafting Team Roster**  
**Project 2010-07 Generator Requirements at the Transmission Interface**

<p>Stephen Enyeart,          Electrical Engineer,          Customer Service          Engineering</p>	<p>Bonneville Power          Administration</p>	<p>(360) 619-          6059          shenyeart@bpa.          gov</p>	<p>Stephen Enyeart is a Customer Service Engineer for Bonneville Power Administration (BPA). In this position, he is responsible for providing technical support for BPA customers, especially those requesting new transmission services of generation interconnection (OASIS queue). He also provides planning assistance for wind and gas turbine project interconnection studies and technical and contractual support for the development of generation interconnection agreements (LGIA).</p> <p>Enyeart is also responsible for developing technical standards for interconnection; requesting, receiving, and validating NERC compliance matters with customers (generation projects); and assisting with commercial interconnection requirements, rates, products, etc. per the BPA Transmission Business Practices and Tariff (OATT).</p> <p>Previously, Enyeart worked in the private sector for various utility consultants, most recently as the Project Manager for design of Utility and Industrial projects. He has a Bachelor of Science degree in Electrical Engineering from Portland State University and is a registered Professional Engineer in the state of Oregon, along with a member of the Institute of Electrical/Electronic Engineers.</p>
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**Drafting Team Roster**  
**Project 2010-07 Generator Requirements at the Transmission Interface**

<p>Bob Goss, Former Manager, Compliance Programs (now retired)</p>	<p>SERC Reliability Corporation  2815 Coliseum Centre Drive Suite 500  Charlotte, NC 28217</p>	<p>(704) 940-8207  rdgoss@bellsouth.net</p>	<p>Through the end of June 2012, Bob Goss was the Manager of Compliance Programs for SERC Reliability Corporation. He managed and participated in Compliance Inquires, Compliance Violation Investigations, the Critical Infrastructure Program and the Registration and Certification Programs. Goss also provided support to the audit program by audit participation and served on several interregional working groups.</p> <p>Previously Goss was with the Southeastern Power Administration as the Deputy Assistant Administrator of Power Resources for 23 years. He acted on behalf of the Assistant Administrator in his absence and served as Team Leader of Southeastern’s Operations Team and oversaw the day-to-day activities of the Power Operations Control Center. His work included operations, maintenance, rehabilitations and replacements of electrical equipment. His duties also included supervision of capacity and energy scheduling, transmission outage scheduling, generation outage scheduling and meeting the compliance requirements of North American Electric Reliability Council (NERC). He also served on Southeastern’s contract negotiating teams.</p> <p>Goss holds a Bachelor of Business Administration from the University of Georgia and has served as a Naval officer and with the U.S. Army Corps of Engineers as a construction representative and civil engineering technician.</p>
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## Drafting Team Roster

### Project 2010-07 Generator Requirements at the Transmission Interface

<p>John L. Simpson, Transmission Consultant</p>	<p>John L. Simpson Transmission Consulting</p>	<p>(281) 954-1853 john.l.simpson @att.net</p>	<p>John L. Simpson is a Transmission Consultant who provides independent transmission consulting services to IPPs and Merchant Electricity Generators in wholesale electric power markets. He helps improve transmission access for existing generating plants, secures highest value interconnection service for new generation additions, and provides consulting services on NERC Reliability Standards requirements for utilities and merchant generators.</p> <p>Formerly Manager of Transmission Policy at RRI Energy, Simpson has extensive experience in securing transmission access for new generating plants and improving transmission access capabilities for existing generating plants by upgrading transmission interconnection rights through new generator interconnection requests. Simpson has provided expert testimony and negotiated settlement agreements for generator reactive power tariffs filed at FERC; negotiated the Standard Large Generator Interconnection Procedures and Agreement with Transmission Providers and other Independent Generators as part of FERC's ANOPR process; and led the efforts to secure approval of the first significant modification to the FERC pro forma open access transmission tariff for an individual utility, i.e., the addition of Network Contract Demand Transmission Service.</p> <p>Simpson has a Bachelor of Science in Electrical Engineering from the University of Colorado.</p>
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**Drafting Team Roster**  
**Project 2010-07 Generator Requirements at the Transmission Interface**

<p>Rick Terrill,  Manager of Regulatory  and Market Support</p>	<p>Luminant Power  500 N. Akard St  Dallas, TX 75070</p>	<p>(214) 875-8750  rick.terrill@luminant.com</p>	<p>Rick Terrill is the Manager of Regulatory and Market Support for five affiliated Registered Generation Owner Entities collectively referred to as Luminant Power, a competitive power generation subsidiary of Energy Future Holdings Corp. Luminant Power has more than 15,400 MW of generation capacity in the ERCOT region, including coal, gas and nuclear powered generation. Terrill’s current responsibilities include managing the overall implementation of activities for the generation fleet to promote compliance with the applicable ERCOT and NERC regulatory requirements.</p> <p>Terrill has more than 33 years of experience with Luminant and its predecessor companies in a wide variety of engineering, support and management roles. In 2006, he assumed the lead responsibility for developing the NERC compliance program for the Luminant Power generating facilities. Since that time, he has served as a member of three NERC Standard Drafting Teams (SDTs) and a regional SDT, and has participated in numerous other NERC standards development projects. In ERCOT, Terrill is a past member of the ERCOT Black Start Task Force, and is a current alternate for the ERCOT CIP Working Group. In addition, he has managed the Luminant Power preparation and responses for six NERC compliance audits, and has a broad range of experience with NERC compliance for generation companies.</p> <p>Terrill received a Bachelor of Science degree in civil engineering from the University of Oklahoma, and earned an MBA in Management from Amber University.</p>
<p>Mallory Huggins,  NERC Staff  Coordinator, Standards  Specialist</p>	<p>NERC  1325 G Street NW  Suite 600  Washington, DC 20005</p>	<p>(202) 644-8062  mallory.huggins@nerc.net</p>	<p>Mallory Huggins serves as a Standards Specialist for NERC. She is responsible for facilitating three projects related to NERC standards development (Project 2010-07, the Adequate Level of Reliability Task Force, and the VRF/VSL revision project) and coordinating industry outreach and communication for NERC’s standards department.</p> <p>Huggins has an M.A. in conflict resolution from Georgetown University and worked for FERC’s Dispute Resolution Service during her two years of graduate school. She has training in facilitation, mediation, and negotiation and earned a B.A. in rhetoric and communication studies from the University of Richmond, with a focus on interpersonal communication and conflict.</p>