
**BEFORE THE
NOVA SCOTIA UTILITY AND REVIEW BOARD
OF THE PROVINCE OF NOVA SCOTIA**

**NORTH AMERICAN ELECTRIC)
RELIABILITY CORPORATION)**

**FIRST QUARTER 2013 APPLICATION
FOR APPROVAL OF RELIABILITY STANDARDS OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION**

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- 1.) NERC Reliability Standards Applicable to Nova Scotia, Approved by FERC in First Quarter 2013
- 2.) PDF Copies of Reliability Standards being filed for approval; and
- 3.) Updated NERC Glossary of Terms for approval

Exhibit C – Informational Summary of Each Reliability Standard Applicable to Nova Scotia, Approved by FERC in First Quarter 2013

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The North American Electric Reliability Corporation (“NERC”) hereby submits to the Nova Scotia Utility and Review Board (“NSUARB”) an application for approval of the NERC Reliability Standards and an updated NERC Glossary of Terms approved by the United States Federal Energy Regulatory Commission (“FERC” or the “Commission”). This filing covers the time period from January 1, 2013 through March 31, 2013 and NERC requests that the Reliability Standards and updated NERC Glossary of Terms be made mandatory and enforceable for users, owners, and operators of the bulk-power system within the Province of Nova Scotia.

In support of this request for approval of the proposed Reliability Standards, NERC submits the following information: (1) an updated list of the currently-effective Reliability Standards as approved by FERC (*see Exhibit A*); (2) Reliability Standards approved by FERC in the first quarter of 2013 and the associated updated NERC Glossary of Terms (*see Exhibit B*); and (3) an informational summary for each Reliability Standard approved by FERC in the first quarter of 2013, including each Standard’s purpose, applicability, and ballot body approval percentages (*see Exhibit C*).

I. NOTICES AND COMMUNICATIONS

Notices and communications regarding this Application may be addressed to:

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II. REQUEST FOR APPROVAL OF RELIABILITY STANDARDS

A. Background: NERC Quarterly Filing of Proposed Reliability Standards

On July 20, 2011, NSUARB issued a decision approving the Reliability Standards and NERC Glossary of Terms that NERC submitted to NSUARB on June 30, 2010, and accepted as guidance the Violation Risk Factors (“VRF”) and Violation Severity Levels (“VSL”) associated with the currently-effective Reliability Standards.¹

NERC has been certified as the Electric Reliability Organization (“ERO”)² in the United States under Section 215 of the Federal Power Act.³ The Reliability Standards

¹ *In the Matter of an Application by North American Electric Reliability Corporation for Approval of its Reliability Standards, and an application by Northeast Power Coordinating Council, Inc. for Approval of its Regional Reliability Criteria*, NSUARB-NERC-R-10 (July 20, 2011) (“NSUARB Decision”).

² Through enactment of the Energy Policy Act of 2005, the U.S. Congress entrusted FERC with the duties of approving and enforcing rules in the U.S. to ensure the reliability of the Nation’s bulk power system, and with the duties of certifying an ERO. On July 20, 2006, FERC certified NERC as the ERO,

contained in **Exhibit B** have been approved as mandatory and enforceable for users, owners, and operators within the United States by FERC.⁴ Some or all of NERC's Reliability Standards are now mandatory in the Canadian Provinces of Alberta, British Columbia, Manitoba, New Brunswick, Nova Scotia, Ontario, Québec, and Saskatchewan.

NERC entered into a Memorandum of Understanding ("MOU") with the NSUARB⁵ and a separate MOU with Nova Scotia Power Incorporated ("NSPI"), and the Northeast Power Coordinating Council, Inc. ("NPCC"),⁶ which became effective on December 22, 2006 and May 11, 2010, respectively. The May 11, 2010 MOU sets forth the mutual understandings of NERC, NSPI, and NPCC regarding the approval and implementation of NERC Reliability Standards and NPCC Regional Reliability Criteria in Nova Scotia and other related matters.

In addition, the NSUARB Decision approved a "quarterly review" process for considering new and amended NERC standards and criteria.⁷ On September 2, 2011, NERC submitted its Second Quarter 2011 application filing to NSUARB, in which NERC committed to file a quarterly application with the NSUARB within sixty days after the end of each quarter for approval of all NERC Reliability Standards and updated Glossary of Terms approved by FERC during that quarter.

The NSUARB Decision also determined that quarterly "applications will not be processed by the Board until [FERC] has approved or remanded the standards in the

charged with developing mandatory and enforceable Reliability Standards, which are subject to FERC review and approval.

3 16 U.S.C. § 824o(f) (2006).

⁴ Those standards marked with an asterisk are not yet effective, but have been approved by FERC.

⁵ See Memorandum of Understanding between Nova Scotia Utility and Review Board and North American Electric Reliability Corporation (signed December 22, 2006).

⁶ See Memorandum of Understanding between Nova Scotia Power Incorporated and the Northeast Power Coordinating Council, Inc. and the North American Electric Reliability Corporation (signed May 11, 2010).

⁷ NSUARB Decision at P 30.

United States.”⁸ Therefore, NERC is only requesting NSUARB approval for those Reliability Standards approved by FERC.

The NSUARB Decision also concluded that NSUARB approval is not required for VRFs and VSLs associated with proposed Reliability Standards.⁹ Thus, NERC does not seek formal approval of VRFs and VSLs associated with the Reliability Standards submitted in this quarterly application. However, because the NSUARB has determined that it will accept the VRFs and VSLs as guidance, NERC is providing a link to the associated FERC-approved VRFs and VSLs for the Reliability Standards for informational purposes.¹⁰

NERC has not included in this filing the full developmental record for the standards, which consists of the draft standards, comments received, responses to the comments by the drafting teams, and the full voting record, because the record for each standard may consist of several thousand pages. NERC will make the full developmental record available to the NSUARB or other interested parties upon request.

B. Overview of NERC Reliability Standards Development Process

NERC Reliability Standards define the requirements for reliably planning and operating the North American bulk-power system. These standards are developed by industry stakeholders using a balanced, open, fair and inclusive process managed by the NERC Standards Committee. The Standards Committee is facilitated by NERC staff and comprised of representatives from ten electricity stakeholder segments. Stakeholders,

⁸ NSUARB Decision at P 30.

⁹ *Id.* at P 33.

¹⁰ NERC’s VRF and VSL matrices can be found at: [http://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United States](http://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United%20States) . See left-hand side of webpage for downloadable documents.

through the balloting process, and the NERC Board of Trustees have approved the standards provided in **Exhibit B**.

NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) and Appendix 3A (Standards Processes Manual) of its Rules of Procedure.¹¹ NERC’s Reliability Standards development process has been approved by the American National Standards Institute as being open, inclusive, balanced, and fair. The NERC Glossary of Terms used in Reliability Standards – most recently updated May 9, 2013 – lists each term that is defined for use in one or more of NERC’s continent-wide or Regional Reliability Standards approved by the NERC Board of Trustees.

C. Description of Proposed Reliability Standards, First Quarter 2013

As explained below, two FERC orders were issued in the first quarter of 2013 approving NERC Reliability Standards and related Glossary terms: (1) an order approving regional Reliability Standard PRC-006-NPCC-1¹² issued on February 21, 2013, and (2) an order approving the Transmission Vegetation Management standard FAC-003-2,¹³ issued on March 21, 2013.”

Reliability Standard	Effective Date
Facilities Design, Connections, and Maintenance (FAC) Standards	
FAC-003-2*	7/1/2014
Protection and Control (PRC) Standards	
PRC-006-NPCC-1*	7/1/2015

* At the time of this filing, all standards marked with an asterisk are not yet effective, but have been approved by FERC and have a future mandatory effective date.

¹¹ NERC’s Rules of Procedure are available at: <http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx>

¹² *Regional Reliability Standard PRC-006-NPCC-1 – Automatic Underfrequency Load Shedding*, Order No. 775, 142 FERC ¶ 61,128 (2013).

¹³ *Revisions to Reliability Standard for Transmission Vegetation Management*, Order No. 777, 142 FERC ¶ 61,208 (2013).

1. PRC-006-NPCC-1

On February 21, 2013, FERC approved regional Reliability Standard PRC-006-NPCC-1 – Automatic Underfrequency Load Shedding in Order No. 775. This regional standard is effective only within the Northeast Power Coordinating Council (“NPCC”) region.

2. FAC-003-2

On March 21, 2013, FERC approved FAC-003-2 – Transmission Vegetation Management and three new definitions to be added to the NERC Glossary of Terms in Order No. 777. The approved definitions of the terms “Right-of-Way,” “Vegetation Inspection” and “Minimum Vegetation Clearance Distance” are included in the updated NERC Glossary of Terms in **Exhibit B**.

III. CONCLUSION

NERC respectfully requests that the NSUARB approve the Reliability Standards and updated NERC Glossary of Terms Used in Reliability Standards, as set forth in

Exhibit B.

Respectfully submitted,

/s/ Stacey Tyrewala

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Exhibit A

List of Currently Effective NERC Reliability Standards

First Quarter 2013

Resource and Demand Balancing (BAL) Standards
BAL-001-0.1a
BAL-002-1
BAL-003-0.1b
BAL-004-0
BAL-004-WECC-01
BAL-005-0.2b
BAL-006-2
BAL-STD-002-0
BAL-502-RFC-02
Critical Infrastructure Protection (CIP) Standards
CIP-001-2a
CIP-002-3
CIP-003-3
CIP-004-3a
CIP-005-3a
CIP-006-3c
CIP-007-3
CIP-008-3
CIP-009-3
Communications (COM) Standards
COM-001-1.1
COM-002-2
Emergency Preparedness and Operations (EOP) Standards
EOP-001-0.1b
EOP-002-3.1
EOP-003-1
EOP-004-1
EOP-005-1
EOP-006-1
EOP-008-0
EOP-009-0
Facilities Design, Connections, and Maintenance (FAC) Standards
FAC-001-0
FAC-002-1
FAC-003-1
FAC-008-3
FAC-010-2.1
FAC-011-2
FAC-013-2
FAC-014-2
FAC-501-WECC-1

First Quarter 2013

Standards Interchange Scheduling and Coordination (INT)
INT-001-3
INT-003-3
INT-004-2
INT-005-3
INT-006-3
INT-007-1
INT-008-3
INT-009-1
INT-010-1
Interconnection Reliability Operations and Coordination (IRO)
IRO-001-1.1
IRO-002-2
IRO-003-2
IRO-004-2
IRO-005-3.1a
IRO-006-5
IRO-008-1
IRO-009-1
IRO-010-1a
IRO-014-1
IRO-015-1
IRO-016-1
IRO-006-EAST-1
IRO-006-WECC-1
IRO-006-TRE-1
Modeling, Data, and Analysis (MOD) Standards
MOD-001-1a
MOD-004-1
MOD-008-1
MOD-010-0
MOD-012-0
MOD-016-1.1
MOD-017-0.1
MOD-018-0
MOD-019-0.1
MOD-020-0
MOD-021-1
MOD-028-1
MOD-029-1a
MOD-030-2
Nuclear (NUC) Standards
NUC-001-2
Personnel Performance, Training, and Qualification (PER) Standards

First Quarter 2013

PER-001-0.2
PER-003-1
PER-004-2
PER-005-1
Protection and Control (PRC) Standards
PRC-001-1
PRC-002-NPCC-01
PRC-004-2a
PRC-004-WECC-1
PRC-005-1b
PRC-007-0
PRC-008-0
PRC-009-0
PRC-010-0
PRC-011-0
PRC-015-0
PRC-016-0.1
PRC-017-0
PRC-018-1
PRC-021-1
PRC-022-1
PRC-023-1
PRC-023-2
Transmission Operations (TOP) Standards
TOP-001-1a
TOP-002-2.1b
TOP-003-1
TOP-004-2
TOP-005-2a
TOP-006-2
TOP-007-0
TOP-008-1
TOP-007-WECC-1
Transmission Planning (TPL) Standards
TPL-001-0.1
TPL-002-0b
TPL-003-0a
TPL-004-0
Voltage and Reactive (VAR) Standards
VAR-001-2
VAR-002-1.1b
VAR-002-WECC-1
VAR-501-WECC-1

Exhibit B

- 1.) NERC Reliability Standards Applicable to Nova Scotia, Approved by FERC in First Quarter 2013**
- 2.) PDF Copies of Reliability Standards Submitted for Approval; and**
- 3.) Updated NERC Glossary of Terms for Approval**

**EXHIBIT B(1): NERC Reliability Standards Applicable to Nova Scotia,
Approved by FERC in First Quarter 2013**

Reliability Standard	Effective Date
Facilities Design, Connections, and Maintenance (FAC) Standards	
FAC-003-2*	7/1/2014
Protection and Control (PRC) Standards	
PRC-006-NPCC-1*	7/1/2015

***At the time of this filing, all standards marked with an asterisk are not yet effective, but have been approved by FERC and have a future mandatory effective date.**

Effective Dates

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.

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

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-003-2
- 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 Transmission Owners

- 4.2. Facilities:** Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal¹, 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.

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

¹ EPCRA 2005 section 1211c: “Access approvals by Federal agencies.”

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 Transmission 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 below² [*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,³
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,⁴
3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,⁴
4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.⁴

M1. Each 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 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 below² [*Violation Risk Factor: High*] [*Time Horizon: Real-time*]:

1. An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage,³
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,⁴
3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,⁴

² This requirement does not apply to circumstances that are beyond the control of 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 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.

³ If a later confirmation of a Fault by the 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.

⁴ 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.

4. An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage⁴
- M2.** Each 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 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]:
- M3.** The maintenance strategies or procedures or processes or specifications provided demonstrate that the Transmission Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)
- R4.** Each Transmission Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the 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].
- M4.** Each 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 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 Transmission Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [Violation Risk Factor: Medium] [Time Horizon: Operations Planning].

- M5.** Each 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)
- R6.** Each 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 ROW⁵ [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].
- M6.** Each 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 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*]:
- Change in expected growth rate/ environmental factors
 - Circumstances that are beyond the control of a Transmission Owner⁶
 - 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

⁵ When the Transmission Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO is granted a time extension that is equivalent to the duration of the time the TO was prevented from performing the Vegetation Inspection.

⁶ Circumstances that are beyond the control of a 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 an applicable regulatory body.

- M7.** Each 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

Regional Entity

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 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.

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 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 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 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 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	N/A	N/A	The Transmission Owner 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 Transmission Owner 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"> • A fall-in from inside the active transmission line ROW • Blowing together of applicable lines and vegetation located inside the active transmission line ROW • A grow-in
R2	Real-time	High	N/A	N/A	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.	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: <ul style="list-style-type: none"> • A fall-in from inside the

						<p>active transmission line ROW</p> <ul style="list-style-type: none"> • Blowing together of applicable lines and vegetation located inside the active transmission line ROW • A grow-in
R3	Long-Term Planning	Lower	N/A	The Transmission Owner 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 Transmission Owner’s applicable lines. (Requirement R3, Part 3.2)	The Transmission Owner 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 Transmission Owner’s applicable lines. Requirement R3, Part 3.1)	The Transmission Owner 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 Transmission Owner’s applicable lines.
R4	Real-time	Medium	N/A	N/A	The Transmission Owner 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 Transmission Owner 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 Transmission Owner 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 Transmission Owner failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The Transmission Owner 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 Transmission Owner 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 Transmission Owner 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 Transmission Owner failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The Transmission Owner 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 Transmission Owner 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 Transmission Owner 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 Transmission 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 a 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 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 a 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 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.

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 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.

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 a 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 a 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 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 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 Transmission Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the TO 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, 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 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 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 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.

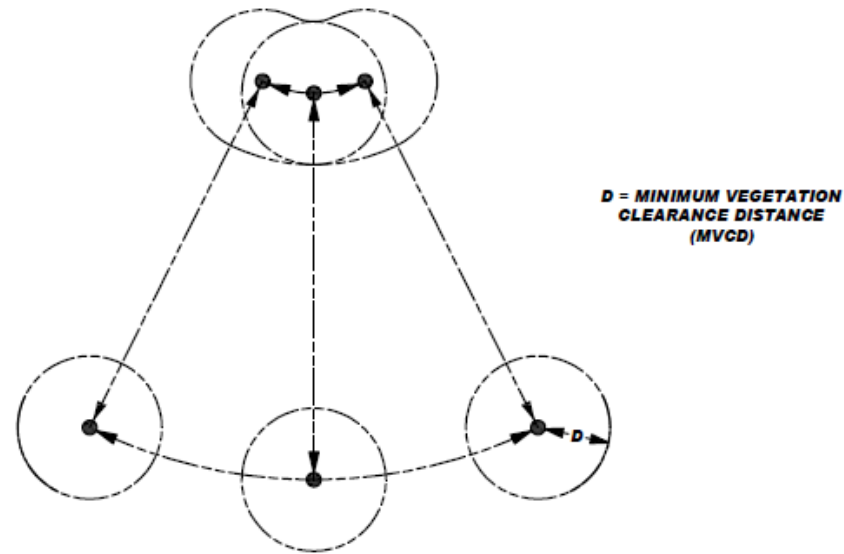


Figure 1

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 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 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 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 the 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. 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 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 Transmission Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when a Transmission Owner operates 2,000 miles of applicable transmission lines this 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 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 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 a Transmission Owner identifies 1,000 miles of applicable transmission lines to be completed in the Transmission Owner’s annual plan, the Transmission Owner will be responsible completing those identified miles. If a 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 a 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 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 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 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 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)⁷
For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)	(AC) Maximum System Voltage (kV) ⁸	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)

⁷ 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.

⁸ Where applicable lines are operated at nominal voltages other than those listed, The Transmission Owner should use the maximum system voltage to determine the appropriate clearance for that line.

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

(AC) Nominal System Voltage (KV)	(AC) Maximum System Voltage (kV) ⁸	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)⁷
 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

Version	Date	Action	Change Tracking
1	TBA	1. Added “Standard Development Roadmap.” 2. Changed “60” to “Sixty” in section A, 5.2. 3. Added “Proposed Effective Date: April 7, 2006” to footer. 4. Added “Draft 3: November 17, 2005” to footer.	01/20/06
1	April 4, 2007	Regulatory Approval - Effective Date	New
2	November 3, 2011	Adopted by the NERC Board of Trustees	
2	March 21, 2013	FERC Order issued approving FAC-003-2	
2	May 9, 2013	Board of Trustees adopted the modification of the VRF for Requirement R2 of FAC-003-2 by raising the VRF from “Medium” to “High.”	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard FAC-003-2 — Transmission Vegetation Management

United States

Standard	Requirement	Enforcement Date	Inactive Date
FAC-003-2	All	07/01/2014	

A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**
2. **Number:** PRC-006-NPCC-1
3. **Purpose:** To provide a regional reliability standard that ensures the development of an effective automatic underfrequency load shedding (UFLS) program in order to preserve the security and integrity of the bulk power system during declining system frequency events in coordination with the NERC UFLS reliability standard characteristics.
4. **Applicability:**
 - 4.1. Generator Owner
 - 4.2. Planning Coordinator
 - 4.3. Distribution Provider
 - 4.4. Transmission Owner
5. **Effective Date:** For the Eastern Interconnection & Québec Interconnection portions of NPCC excluding the Independent Electricity System Operator (IESO) Planning Coordinator area of NPCC in Ontario, Canada:

The effective date for Requirements R1, R2, R3, R4, R5, R6, and R7 is the first day of the first calendar quarter following applicable regulatory approval but no earlier than January 1, 2016. The effective date for Requirements R8 through R23 is the first day of the first calendar quarter two years following applicable governmental and regulatory approval.

For the Independent Electricity System Operator (IESO) Planning Coordinator's area of NPCC in Ontario, Canada:

All requirements are effective the first day of the first calendar quarter following applicable governmental and regulatory approval but no earlier than April 1, 2017.

B. Requirements

- R1** Each Planning Coordinator shall establish requirements for entities aggregating their UFLS programs for each anticipated island and requirements for compensatory load shedding based on islanding criteria (required by the NERC PRC Standard on UFLS). [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

- R2** Each Planning Coordinator shall, within 30 days of completion of its system studies required by the NERC PRC Standard on UFLS, identify to the Regional Entity the generation facilities within its Planning Coordinator Area necessary to support the UFLS program performance characteristics. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]
- R3** Each Planning Coordinator shall provide to the Transmission Owner, Distribution Provider, and Generator Owner within 30 days upon written request the requirements for entities aggregating the UFLS programs and requirements for compensatory load shedding program derived from each Planning Coordinator's system studies as determined by Requirement R1. [Violation Risk Factor: Low] [Time Horizon: Long Term Planning]
- R4** Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall implement an automatic UFLS program reflecting normal operating conditions excluding outages for its Facilities based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3, or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1 and acting as a single entity, provide an aggregated automatic UFLS program that sheds their coincident peak aggregated net Load, based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]
- R5** Each Distribution Provider or Transmission Owner that must arm its load to trip on underfrequency in order to meet its requirements as specified and by doing so exceeds the tolerances and/or deviates from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Requirement R4 above, as applicable depending on its total peak net Load shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]
- 5.1 Inform its Planning Coordinator of the need to exceed the stated tolerances or the number of stages as shown in UFLS Attachment C, Table 1 if applicable and
 - 5.2 Provide its Planning Coordinator with a technical study that demonstrates that the Distribution Providers or Transmission Owners specific deviations

from the requirements of UFLS Attachment C, Table 1 will not have a significant adverse impact on the bulk power system.

- 5.3 Inform its Planning Coordinator of the need to exceed the stated tolerances of UFLS Attachment C, Table 2 or Table 3, and in the case of Attachment C, Table 2 only, the need to deviate from providing two stages of UFLS, if applicable, and
- 5.4 Provide its Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or Transmission Owner to comply with UFLS Attachment C Table 2 or Attachment C Table 3.

R6 Each Distribution Provider and Transmission Owner in the Québec Interconnection portion of NPCC shall implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4 or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R7 Each Distribution Provider and Transmission Owner shall set each underfrequency relay that is part of its region's UFLS program with the following minimum time delay:

- 7.1 Eastern Interconnection – 100 ms
- 7.2 Québec Interconnection – 200 ms

[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R8 Each Planning Coordinator shall develop and review once per calendar year settings for inhibit thresholds (such as but not limited to voltage, current and time) to be utilized within its region's UFLS program. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

- R9** Each Planning Coordinator shall provide each Transmission Owner and Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds within 30 days of the initial determination of those inhibit thresholds and within 30 days of any changes to those thresholds. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]
- R10** Each Distribution Provider and Transmission Owner shall implement the inhibit threshold settings based on the notification provided by the Planning Coordinator in accordance with Requirement R9. [Violation Risk Factor: High] [Time Horizon: Operations Planning]
- R11** Each Distribution Provider and Transmission Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with R9. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]
- R12** Each Transmission Owner and Distribution Provider shall annually provide documentation, with no more than 15 months between updates, to its Planning Coordinator of the actual net Load that would have been shed by the UFLS relays at each UFLS stage coincident with their integrated hourly peak net Load during the previous year, as determined by measuring actual metered Load through the switches that would be opened by the UFLS relays. [Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]
- R13** Each Generator Owner shall set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted in Requirements R16 and R19. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]
- R14** Each Generator Owner shall transmit the generator underfrequency trip setting and time delay to its Planning Coordinator within 45 days of the Planning Coordinator's request. [Violation Risk Factor: High] [Time Horizon: Operations Planning]
- R15** Each Generator Owner with a new generating unit, scheduled to be in service on or after the effective date of this Standard, or an existing generator increasing its net

capability by greater than 10% shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

15.1 Design measures to prevent the generating unit from tripping directly or indirectly for underfrequency conditions above the appropriate generator tripping threshold curve in Figure 1.

15.2 Design auxiliary system(s) or devices used for the control and protection of auxiliary system(s), necessary for the generating unit operation such that they will not trip the generating unit during underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1.

R16 Each Generator Owner of existing non-nuclear units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1 shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

16.1 Set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations.

16.2 Transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinator.

16.3 Have compensatory load shedding, as provided by a Distribution Provider or Transmission Owner that is adequate to compensate for the loss of their generator due to early tripping.

R17 Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall apply the criteria described in Attachment A to determine the compensatory load shedding that is required in Requirement R16.3 for generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R18 Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall apply the criteria described in Attachment B to determine the compensatory load shedding that is

required in Requirement R16.3 for generating units in its respective NPCC area.
[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R19 Each Generator Owner of existing nuclear generating plants with units that have underfrequency relay threshold settings above the Eastern Interconnection generator tripping curve in Figure 1, based on their licensing design basis, shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

- 19.1 Set the underfrequency protection to operate at as low a frequency as possible in accordance with the plant design and licensing limitations but not greater than 57.8Hz.
- 19.2 Set the frequency trip setting upper tolerance to no greater than + 0.1 Hz.
- 19.3 Transmit the initial frequency trip setting and any changes to the setting and the technical basis for the settings to the Planning Coordinator.

R20 The Planning Coordinator shall update its UFLS program database as specified by the NERC PRC Standard on UFLS. This database shall include the following information: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

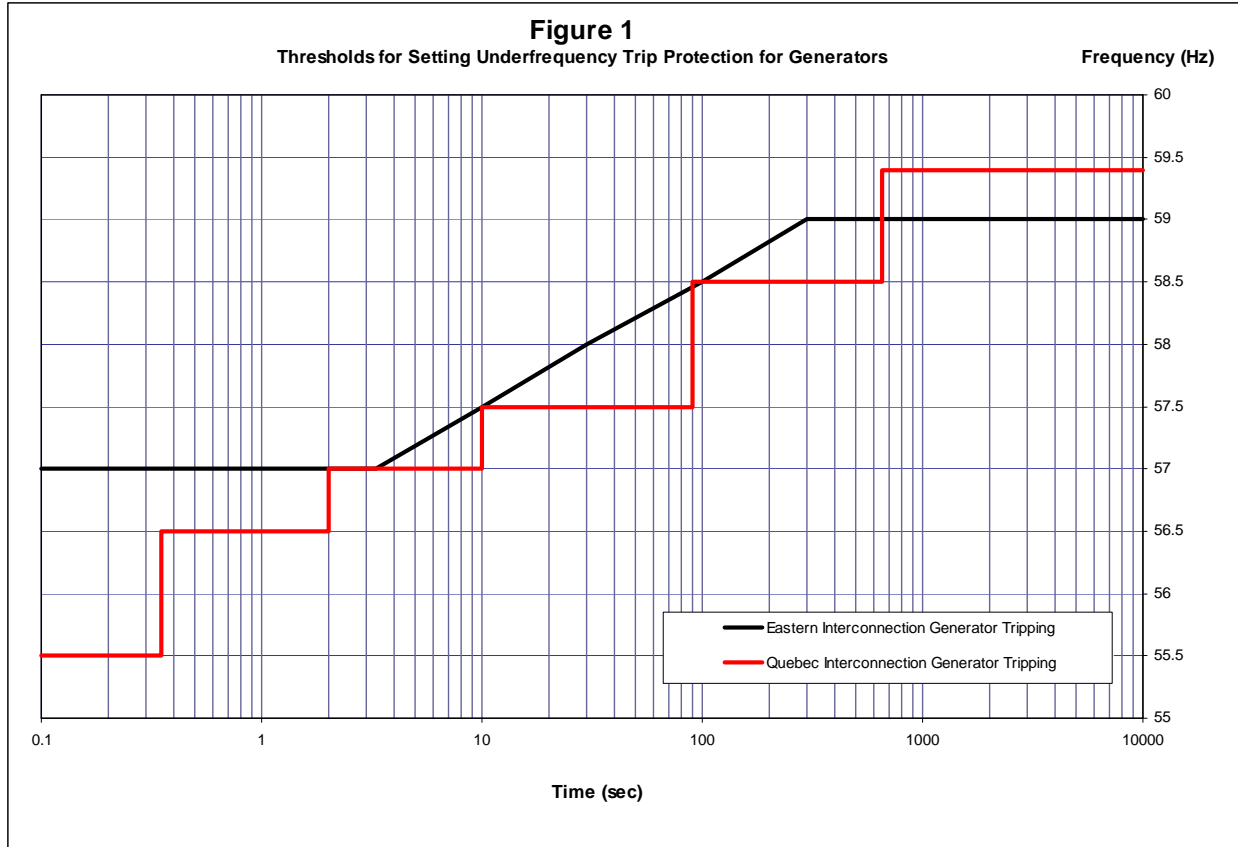
- 20.1 For each UFLS relay, including those used for compensatory load shedding, the amount and location of load shed at peak, the corresponding frequency threshold and time delay settings.
- 20.2 The buses at which the Load is modeled in the NPCC library power flow case.
- 20.3 A list of all generating units that may be tripped for underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, including the frequency trip threshold and time delay for each protection system.
- 20.4 The location and amount of additional elements to be switched for voltage control that are coordinated with UFLS program tripping.
- 20.5 A list of all UFLS relay inhibit functions along with the corresponding settings and locations of these relays.

R21 Each Planning Coordinator shall notify each Distribution Provider, Transmission Owner, and Generator Owner within its Planning Coordinator area of changes to load

distribution needed to satisfy UFLS program performance characteristics as specified by the NERC PRC Standard on UFLS.[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R22 Each Distribution Provider, Transmission Owner and Generator Owner shall implement the load distribution changes based on the notification provided by the Planning Coordinator in accordance with Requirement R21. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R23 Each Distribution Provider, Transmission Owner and Generator Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with Requirement R21. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]



C. Measures

- M1** Each Planning Coordinator shall have evidence such as reports, system studies and/or real time power flow data captured from actual system events and other dated documentation that demonstrates it meets Requirement R1.
- M2.** Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets requirement R2.
- M3** Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets Requirement R3.
- M4** Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall have evidence such as documentation or reports containing the location and amount of load to be tripped, and the corresponding frequency thresholds, on those circuits included in its UFLS program to achieve the individual and cumulative percentages identified in Requirement R4. (Attachment C Tables 1-3).
- M5** Each Distribution Provider or Transmission Owner shall have evidence such as reports, analysis, system studies and dated documentation that demonstrates that it meets Requirement R5.
- M6** Each Distribution Provider and Transmission Owner in the Québec Interconnection shall have evidence such as documentation or reports containing the location and amount of load to be tripped and the corresponding frequency thresholds on those circuits included in its UFLS program to achieve the load values identified in Table 4 of Requirement R6. (Attachment C Table 4).
- M7** Each Distribution Provider and Transmission Owner shall have evidence such as documentation or reports that their underfrequency relays have been set with the minimum time delay, in accordance with Requirement R7.
- M8** Each Planning Coordinator shall have evidence such as reports, system studies or analysis that demonstrates that it meets Requirement R8.

- M9** Each Planning Coordinator shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R9.
- M10** Each Distribution Provider and Transmission Owner shall provide evidence such as test reports, data sheets or other documentation that demonstrates that it meets Requirement R10.
- M11** Each Distribution Provider and Transmission Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates that it meets Requirement R11.
- M12** Each Distribution Provider and Transmission Owner shall provide evidence such as reports, spreadsheets or other dated documentation submitted to its Planning Coordinator that indicates the frequency set point, the net amount of load shed and the percentage of its peak load at each stage of its UFLS program coincident with the integrated hourly peak of the previous year that demonstrates that it meets Requirement R12.
- M13** Each Generator Owner shall provide evidence such as reports, data sheets, spreadsheets or other documentation that demonstrates that it meets Requirement R13.
- M14** Each Generator Owner shall provide evidence such as emails, letters or other dated documentation that demonstrates that it meets Requirement R14.
- M15** Each Generator Owner shall provide evidence such as reports, data sheets, specifications, memorandum or other documentation that demonstrates that it meets Requirement R15.
- M16** Each Generator Owner with existing non-nuclear units in service prior to the effective date of this Standard which have underfrequency tripping that is not compliant with Requirement R13 shall provide evidence such as reports, spreadsheets, memorandum or dated documentation demonstrating that it meets Requirement R16.
- M17** Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall provide evidence such as emails, memorandum or other documentation that

demonstrates that it followed the methodology described in Attachment A and meets Requirement R17.

M18 Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall provide evidence such as emails, memorandum, or other documentation that demonstrates that it followed the methodology described in Attachment B and meets Requirement R18.

M19 Each Generator Owner of nuclear units that have been specifically identified by NPCC as having generator trip settings above the generator trip curve in Figure 1 shall provide evidence such as letters, reports and dated documentation that demonstrates that it meets Requirement R19.

M20 Each Planning Coordinator shall provide evidence such as spreadsheets, system studies, or other documentation that demonstrates that it meets the requirements of Requirement R20.

M21 Each Planning Coordinator shall provide evidence such as emails, memorandum or other dated documentation that it meets Requirement R21.

M22 Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as reports, spreadsheets or other documentation that demonstrates that it meets Requirement R22.

M23 Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates it meets Requirement 23.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

NPCC Compliance Committee

1.2. Compliance Monitoring Period and Reset Time Frame

Not Applicable

1.3. Data Retention

The Distribution Provider and Transmission Owner shall keep evidences for three calendar years for Measures 4, 5, 6,7,10, 11, and 12.

The Planning Coordinator shall keep evidence for three calendar years for Measures 1, 2, 3, 8, 9, 20, and 21.

The Planning Coordinator in Ontario, Quebec, and the Maritime Provinces shall keep evidence for three calendar years for Measure 17.

The Distribution Provider, Transmission Owner, and Generator Owner shall keep evidences for three calendar years for Measures 18, 22, and 23.

The Generator Owner shall keep evidence for three calendar years for Measures 13, 14, 15, 16, and 19.

1.4. Compliance Monitoring and Assessment Processes

Self -Certifications.

Spot Checking.

Compliance Audits.

Self- Reporting.

Compliance Violation Investigations.

Complaints.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	Planning Coordinator did not establish requirements for entities aggregating their UFLS programs. or Did not establish requirements for compensatory load shedding.	Planning Coordinator did not establish requirements for entities aggregating their UFLS programs and did not establish requirements for compensatory load shedding.
R2	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 30 days but less than 41 days after completion of the system studies.	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 40 days but less than 51 days after completion of the system studies.	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 50 days but less than 61 days after completion of the system studies.	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 60 days after completion of the system studies. or The Planning Coordinator did not identify the generation facilities within its Planning Coordinator Area necessary to support the UFLS program.
R3	The Planning Coordinator provided the requested information, but did so more than 30 days but less than 41 days to the requesting entity.	The Planning Coordinator provided the requested information, but did so more than 40 days but less than 51 days to the requesting entity.	The Planning Coordinator provided the requested information, but did so more than 50 days but less than 61 days to the requesting entity.	The Planning Coordinator provided the requested information, but did so more than 60 days after the request. or The Planning Coordinator failed to provide the requested

				information.
R4	N/A	N/A	N/A	The Distribution Provider or Transmission Owner failed to implement an automatic UFLS program reflecting normal operating conditions excluding outages, for its Facilities or collectively implemented by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on frequency thresholds, total nominal operating time, and amounts specified in the appropriate included tables.
R5	N/A	The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not inform the Planning Coordinator of the need to exceed the stated	The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not provide the Planning Coordinator with an analysis demonstrating that no alternative load shedding	The Distribution Provider or Transmission Owner did not arm its load to trip on underfrequency in order to meet its minimum obligations and in doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load.

		tolerances of UFLS Table 2 or Table 3, and in the case of Table 2 only, the need to deviate from providing two stages of UFLS.	solution is available that would allow the Distribution Provider or Transmission Owner to comply with the appropriate table.	
R6	N/A	N/A	N/A	The Distribution Provider or Transmission Owner in the Québec Interconnection portion of NPCC did not implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4 or did not collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4.
R7	N/A	N/A	N/A	The Distribution Provider or Transmission Owner failed to set

Standard PRC-006-NPCC-1 Automatic Underfrequency Load Shedding

				an underfrequency relay that is part of its region's UFLS program as specified in Requirement R7.
R8	N/A	N/A	The Planning Coordinator developed inhibit thresholds as specified in Requirement R8 but did not perform the review once per calendar year.	The Planning Coordinator did not develop inhibit thresholds as specified in Requirement R8.
R9	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 30 days but less than 41 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 40 days but less than 51 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 50 days but less than 61 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 60 days after the initial determination or any subsequent change to the inhibit thresholds. or The Planning Coordinator did not provide to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds.
R10	N/A	N/A	N/A	The Distribution Provider or Transmission Owner did not implement the inhibit threshold based on the notification provided by the Planning Coordinator in accordance with

				Requirement R9.
R11	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 90 days but less than 101 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 100 days but less than 111 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 110 days but less than 121 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 120 days after the request from the Planning Coordinator. or The Distribution Provider or Transmission Owner did not develop its implementation plan.
R12	N/A	N/A	N/A	The Transmission Owner or Distribution Provider did not provide documentation to its Planning Coordinator of actual net load data or updates to the data that would be shed by the UFLS relays, as determined by measuring actual metered load through the switches that would be opened by the UFLS relays, that were armed to shed at each UFLS stage coincident with their integrated hourly peak during the previous year.
R13	N/A	N/A	N/A	The Generator Owner did not set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in

				Figure 1, except as otherwise exempted.
R14	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 45 days and less than 56 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 55 days and less than 66 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 65 days and less than 76 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 75 days after the Planning Coordinator's request. or The Generator Owner did not transmit the generator underfrequency trip setting and time delay to its Planning Coordinator.
R15	N/A	N/A	The Generator Owner did not fulfill the obligation of Requirement R15; Part 15.1 OR did not fulfill the obligation of Requirement R15, Part 15.2.	The Generator Owner did not fulfill the obligation of Requirement R15, Part 15.1 and did not fulfill the obligation of Requirement R15, Part 15.2.
R16	N/A	The Generator Owner did not fulfill the obligation of Requirement R16, Part 16.2.	The Generator Owner did not fulfill the obligation of Requirement R16; Part 16.1 OR did not fulfill the obligation of	The Generator Owner did not fulfill the obligation of Requirement R16, Part 16.1 and did not fulfill the obligation of

			Requirement R16, Part 16.3.	Requirement R16, Part 16.3.
R17	N/A	N/A	N/A	The Planning Coordinator did not apply the methodology described in Attachment A to determine the compensatory load shedding that is required.
R18	N/A	N/A	N/A	The Generator Owner, Distribution Provider, or Transmission Owner did not apply the methodology described in Attachment B to determine the compensatory load shedding that is required.
R19	N/A	The Generator Owner did not fulfill the obligation of Requirement R19, Part 19.3.	The Generator Owner did not fulfill the obligation of Requirement R19; Part 19.1 OR did not fulfill the obligation of Requirement R19, Part 19.2.	The Generator Owner did not fulfill the obligation of Requirement R19, Part 19.1 and did not fulfill the obligation of Requirement R19, Part 19.2.
R20	The Planning Coordinator did not have data in its database for one of the parameters listed in Requirement 20, Parts 20.1 through 20.5.	The Planning Coordinator did not have data in its database for two of the parameters listed in Requirement 20, Parts 20.1 through 20.5.	The Planning Coordinator did not have data in its database for three of the parameters listed in Requirement 20, Parts 20.1 through 20.5.	The Planning Coordinator did not have data in its database for four or more of the parameters listed in Requirement 20, Parts 20.1 through 20.5.

R21	N/A	N/A	N/A	The Planning Coordinator did not notify a Distribution Provider, Transmission Owner, or Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program requirements.
R22	N/A	N/A	N/A	The Distribution Provider, Transmission Owner, or Generator Owner did not implement the load distribution changes based on the notification provided by the Planning Coordinator.
R23	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 90 days but less than 101 days after the request from the Planning Coordinator.	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 100 days but less than 111 days after the request from the Planning Coordinator.	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 110 days but less than 121 days after the request from the Planning Coordinator.	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 120 days after the request from the Planning Coordinator. or The Distribution Provider. Transmission Owner or Generator Owner did not develop its implementation plan.

Version History

Version	Date	Action	Change Tracking
1	November 20, 2011	Region BOD Approval	
1	February 9, 2012	Adopted by Board of Trustees	
1	February 21, 2013	Order issued by FERC approving PRC-006-NPCC-1 (approval effective April 29, 2013)	

PRC-006-NPCC-1 Attachment A

Compensatory Load Shedding Criteria for Ontario, Quebec, and the Maritime Provinces:

The Planning Coordinator in Ontario, Quebec and the Maritime provinces is responsible for establishing the compensatory load shedding requirements for all existing non-nuclear units in its NPCC area with underfrequency protections set to trip above the appropriate curve in Figure 1. In addition, it is the Planning Coordinator's responsibility to communicate these requirements to the appropriate Distribution Provider or Transmission Owner and to ensure that adequate compensatory load shedding is provided in all islands identified in Requirement R1 in which the unit may operate.

The methodology below provides a set of criteria for the Planning Coordinator to follow for determining compensatory load shedding requirements:

1. The Planning Coordinator shall identify, compile and maintain an updated list of all existing non-nuclear generating units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1. The list shall include the following information for each unit:
 - 1.1 Generator name and generating capacity
 - 1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
 - 1.3 Physical and electrical location of the unit
 - 1.4 All islands within which the unit may operate, as identified in Requirement R1
2. For each generating unit identified in (1) above, the Planning Coordinator shall establish the requirements for compensatory load shedding based on criteria outlined below:
 - 2.1 Arrange for a Distribution Provider or Transmission Owner that owns UFLS relays within the island(s) identified by the Planning Coordinator in Requirement R1 within which the generator may operate to provide compensatory load shedding.
 - 2.2 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4..
 - 2.3 The compensatory load shedding shall be provided at the UFLS program stage (or threshold stage for Quebec) with a frequency threshold setting that corresponds to the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1 during an underfrequency event. If the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1 does not correspond to a specific UFLS program stage threshold setting,

the compensatory load shedding shall be provided at the UFLS program stage with a frequency threshold setting that is higher than the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1.

2.4 The amount of compensatory load shedding shall be equivalent ($\pm 5\%$) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent ($\pm 5\%$) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-1 Attachment B

Compensatory Load Shedding Criteria for ISO-NE and NYISO:

The Generator Owner in the New England states or New York State are responsible for establishing a compensatory load shedding program for all existing non-nuclear units with underfrequency protection set to trip above the appropriate curve in Figure 1 of this standard. The Generator Owner shall follow the methodology below to determine compensatory load shedding requirements:

1. The Generator Owner shall identify and compile a list of all existing non-nuclear generating units in service prior to the effective date of this standard that has underfrequency protection set to trip above the appropriate curve in Figure 1. The list shall include the following information associated with each unit:
 - 1.1 Generator name and generating capacity
 - 1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
 - 1.3 Physical and electrical location of the unit
 - 1.4 Smallest island within which the unit may operate as identified by the Planning Coordinator in Requirement R1 of this Standard.
2. For each generating unit identified in (1) above, the Generator Owner shall establish the requirements for compensatory load shedding based on criteria outlined below:
 - 2.1 In cases where a Distribution Provider or Transmission Owner has coordinated protection settings with the Generator Owner to cause the generator to trip above the appropriate curve in Figure 1, the Distribution Provider or Transmission Owner is responsible to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.
 - 2.2 In cases where a Generator Owner has a generator that cannot physically meet the set points defined by the appropriate curve in Figure 1, the Generator Owner shall arrange for a Distribution Provider or Transmission Owner to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.
 - 2.3 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4.

2.4 The compensatory load shedding shall be provided at the UFLS program stage with the frequency threshold setting at or closest to but above the frequency at which the subject generator will trip.

2.5 The amount of compensatory load shedding shall be equivalent ($\pm 5\%$) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent ($\pm 5\%$) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-1 Attachment C

UFLS Table 1: Eastern Interconnection			
Distribution Providers and Transmission Owners with 100 MW or more of peak net Load shall implement a UFLS program with the following attributes:			
Frequency Threshold (Hz)	Total Nominal Operating Time (s) ¹	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
59.5	0.30	6.5 – 7.5	6.5 – 7.5
59.3	0.30	6.5 – 7.5	13.5 – 14.5
59.1	0.30	6.5 – 7.5	20.5 – 21.5
58.9	0.30	6.5 – 7.5	27.5 – 28.5
59.5	10.0	2 – 3	29.5 31.5

UFLS Table 2: Eastern Interconnection				
Distribution Providers and Transmission Owners with 50 MW or more and less than 100 MW of peak net Load shall implement a UFLS program with the following attributes:				
UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time(s) ¹	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	14-25	14-25
2	59.1	0.30	14-25	28-50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

UFLS Table 3: Eastern Interconnection

Distribution Providers and Transmission Owners with 25 MW or more and less than 50 MW of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time (s) ¹	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	28-50	28-50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

UFLS Table 4: Quebec Interconnection					
	Rate	Frequency (Hz)	MW at peak (*Load must be fixed at all times when above 60% of peak load..)	Mvar at peak	Total Nominal Operating Time (s) ²
Threshold Stage 1	—	58.5	1000*	1000	0.30
Threshold Stage 2	—	58.0	800*	800	0.30
Threshold Stage 3	—	57.5	800	800	0.30
Threshold Stage 4	—	57.0	800	800	0.30
Threshold Stage 5 (anti-stall)	—	59.0	500	500	20.0
Slope Stage 1	-0.3 Hz/s	58.5	400	400	0.30
Slope Stage 2	-0.4 Hz/s	59.8	800*	800	0.30
Slope Stage 3	-0.6 Hz/s	59.8	800*	800	0.30
Slope Stage 4	-0.9 Hz/s	59.8	800	800	0.30

2. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communications time, and the rated breaker interrupting time. The underfrequency relay operating time shall be measured from the time when the frequency passes through the frequency threshold set point.

* FOR INFORMATIONAL PURPOSES ONLY *

Enforcement Dates: Standard PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding

United States

Standard	Requirement	Enforcement Date	Inactive Date
PRC-006-NPCC-1	R1.	01/01/2016	
PRC-006-NPCC-1	R2.	01/01/2016	
PRC-006-NPCC-1	R3.	01/01/2016	
PRC-006-NPCC-1	R4.	01/01/2016	
PRC-006-NPCC-1	R5.	01/01/2016	
PRC-006-NPCC-1	R6.	01/01/2016	
PRC-006-NPCC-1	R7.	01/01/2016	
PRC-006-NPCC-1	R8.	07/01/2015	
PRC-006-NPCC-1	R9.	07/01/2015	
PRC-006-NPCC-1	R10.	07/01/2015	
PRC-006-NPCC-1	R11.	07/01/2015	
PRC-006-NPCC-1	R12.	07/01/2015	
PRC-006-NPCC-1	R13.	07/01/2015	
PRC-006-NPCC-1	R14.	07/01/2015	
PRC-006-NPCC-1	R15.	07/01/2015	
PRC-006-NPCC-1	R16.	07/01/2015	
PRC-006-NPCC-1	R17.	07/01/2015	
PRC-006-NPCC-1	R18.	07/01/2015	
PRC-006-NPCC-1	R19.	07/01/2015	
PRC-006-NPCC-1	R20.	07/01/2015	
PRC-006-NPCC-1	R21.	07/01/2015	
PRC-006-NPCC-1	R22.	07/01/2015	
PRC-006-NPCC-1	R23.	07/01/2015	

Glossary of Terms Used in NERC Reliability Standards

Updated May 9, 2013

Introduction:

This Glossary lists each term that was defined for use in one or more of NERC's continent-wide or Regional Reliability Standards and adopted by the NERC Board of Trustees from February 8, 2005 through May 9, 2013.

This reference is divided into two sections, and each section is organized in alphabetical order. The first section identifies all terms that have been adopted by the NERC Board of Trustees for use in continent-wide standards; the second section identifies all terms that have been adopted by the NERC Board of Trustees for use in regional standards. (WECC, NPCC and *ReliabilityFirst* are the only Regions that have definitions approved by the NERC Board of Trustees. If other Regions develop definitions for approved Regional Standards using a NERC-approved standards development process, those definitions will be added to the Regional Definitions section of this glossary.)

Most of the terms identified in this glossary were adopted as part of the development of NERC's initial set of reliability standards, called the "Version 0" standards. Subsequent to the development of Version 0 standards, new definitions have been developed and approved following NERC's Reliability Standards Development Process, and added to this glossary following board adoption, with the "FERC approved" date added following a final Order approving the definition.

Immediately under each term is a link to the archive for the development of that term.

Definitions that have been adopted by the NERC Board of Trustees but have not been approved by FERC, or FERC has not approved but has directed be modified, are shaded in blue. Definitions that have been remanded or retired are shaded in orange.

Any comments regarding this glossary should be reported to the following:
sarcomm@nerc.com with "Glossary Comment" in the subject line.

Continent-wide Definitions:

A..... 5

B..... 9

C..... 18

D..... 23

E..... 26

F..... 29

G..... 33

H..... 34

I..... 35

J..... 39

L..... 40

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P..... 49

R..... 54

S..... 61

T..... 64

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W..... 68

Y 68

Regional Definitions:

Reliability*First* Regional Definitions..... 69

NPCC Regional Definitions 70

WECC Regional Definitions 71

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Adequacy [Archive]		2/8/2005	3/16/2007	The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
Adjacent Balancing Authority [Archive]		2/8/2005	3/16/2007	A Balancing Authority Area that is interconnected another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
Adverse Reliability Impact [Archive]		2/7/2006	3/16/2007	The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection.
Adverse Reliability Impact [Archive]		8/4/2011		The impact of an event that results in Bulk Electric System instability or Cascading.
After the Fact [Archive]	ATF	10/29/2008	12/17/2009	A time classification assigned to an RFI when the submittal time is greater than one hour after the start time of the RFI.
Agreement [Archive]		2/8/2005	3/16/2007	A contract or arrangement, either written or verbal and sometimes enforceable by law.
Alternative Interpersonal Communication [Archive]		11/7/2012		Any Interpersonal Communication that is able to serve as a substitute for, and does not utilize the same infrastructure (medium) as, Interpersonal Communication used for day-to-day operation.

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Altitude Correction Factor [Archive]		2/7/2006	3/16/2007	A multiplier applied to specify distances, which adjusts the distances to account for the change in relative air density (RAD) due to altitude from the RAD used to determine the specified distance. Altitude correction factors apply to both minimum worker approach distances and to minimum vegetation clearance distances.
Ancillary Service [Archive]		2/8/2005	3/16/2007	Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider's transmission system in accordance with good utility practice. <i>(From FERC order 888-A.)</i>
Anti-Aliasing Filter [Archive]		2/8/2005	3/16/2007	An analog filter installed at a metering point to remove the high frequency components of the signal over the AGC sample period.
Area Control Error [Archive]	ACE	2/8/2005	3/16/2007	The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error.
Area Control Error [Archive]	ACE	12/19/2012		The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias, correction for meter error, and Automatic Time Error Correction (ATEC), if operating in the ATEC mode. ATEC is only applicable to Balancing Authorities in the Western Interconnection.

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Area Interchange Methodology [Archive]		08/22/2008	11/24/2009	The Area Interchange methodology is characterized by determination of incremental transfer capability via simulation, from which Total Transfer Capability (TTC) can be mathematically derived. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC, and Postbacks and counterflows are added, to derive Available Transfer Capability. Under the Area Interchange Methodology, TTC results are generally reported on an area to area basis.
Arranged Interchange [Archive]		5/2/2006	3/16/2007	The state where the Interchange Authority has received the Interchange information (initial or revised).
Automatic Generation Control [Archive]	AGC	2/8/2005	3/16/2007	Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction.
Available Flowgate Capability [Archive]	AFC	08/22/2008	11/24/2009	A measure of the flow capability remaining on a Flowgate for further commercial activity over and above already committed uses. It is defined as TFC less Existing Transmission Commitments (ETC), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, and plus counterflows.
Available Transfer Capability [Archive]	ATC	2/8/2005	3/16/2007	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin.

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Available Transfer Capability [Archive]	ATC	08/22/2008	11/24/2009	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less Existing Transmission Commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, plus counterflows.
Available Transfer Capability Implementation Document [Archive]	ATCID	08/22/2008	11/24/2009	A document that describes the implementation of a methodology for calculating ATC or AFC, and provides information related to a Transmission Service Provider's calculation of ATC or AFC.
ATC Path [Archive]		08/22/2008	Not approved; Modification directed 11/24/09	Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path ¹ .

¹ See 18 CFR 37.6(b)(1)

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Balancing Authority [Archive]	BA	2/8/2005	3/16/2007	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
Balancing Authority Area [Archive]		2/8/2005	3/16/2007	The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.
Base Load [Archive]		2/8/2005	3/16/2007	The minimum amount of electric power delivered or required over a given period at a constant rate.
BES Cyber Asset [Archive]		11/26/12		A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems. (A Cyber Asset is not a BES Cyber Asset if, for 30 consecutive calendar days or less, it is directly connected to a network within an ESP, a Cyber Asset within an ESP, or to a BES Cyber Asset, and it is used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.)

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
BES Cyber System [Archive]		11/26/12		One or more BES Cyber Assets logically grouped by a responsible entity to perform one or more reliability tasks for a functional entity.
BES Cyber System Information [Archive]		11/26/12		Information about the BES Cyber System that could be used to gain unauthorized access or pose a security threat to the BES Cyber System. BES Cyber System Information does not include individual pieces of information that by themselves do not pose a threat or could not be used to allow unauthorized access to BES Cyber Systems, such as, but not limited to, device names, individual IP addresses without context, ESP names, or policy statements. Examples of BES Cyber System Information may include, but are not limited to, security procedures or security information about BES Cyber Systems, Physical Access Control Systems, and Electronic Access Control or Monitoring Systems that is not publicly available and could be used to allow unauthorized access or unauthorized distribution; collections of network addresses; and network topology of the BES Cyber System.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Blackstart Capability Plan [Archive]		2/8/2005 Will be retired when EOP-005-2 becomes enforceable on (7/1/13)	3/16/2007	A documented procedure for a generating unit or station to go from a shutdown condition to an operating condition delivering electric power without assistance from the electric system. This procedure is only a portion of an overall system restoration plan.
Blackstart Resource [Archive]		8/5/2009	3/17/11	A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan.
Block Dispatch [Archive]		08/22/2008	11/24/2009	A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, the capacity of a given generator is segmented into loadable "blocks," each of which is grouped and ordered relative to other blocks (based on characteristics including, but not limited to, efficiency, run of river or fuel supply considerations, and/or "must-run" status).

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System [Archive]	BES	2/8/2005	3/16/2007	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.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System [Archive]	BES	01/18/2012	07/01/2013	<p>Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.</p> <p>Inclusions:</p> <ul style="list-style-type: none"> • I1 - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded under Exclusion E1 or E3. • I2 - Generating resource(s) with gross individual nameplate rating greater than 20 MVA or gross plant/facility aggregate nameplate rating greater than 75 MVA including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above. • I3 - Blackstart Resources identified in the Transmission Operator's restoration plan. • I4 - Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System (Continued)	BES			<p>I5 –Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1.</p> <p>Exclusions:</p> <ul style="list-style-type: none"> • E1 - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and: <ul style="list-style-type: none"> a) Only serves Load. Or, b) Only includes generation resources, not identified in Inclusion I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or, c) Where the radial system serves Load and includes generation resources, not identified in Inclusion I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating). <p>Note – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.</p>

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System (Continued)	BES			<ul style="list-style-type: none"> • E2 - A generating unit or multiple generating units on the customer’s side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority. • E3 - Local networks (LN): A group of contiguous transmission Elements operated at or above 100 kV but less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN’s emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customer Load and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System (Continued)	BES			<p>a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusion I3 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);</p> <p>b) Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and</p> <p>c) Not part of a Flowgate or transfer path: The LN does not contain a monitored Facility of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).</p> <ul style="list-style-type: none"> • E4 – Reactive Power devices owned and operated by the retail customer solely for its own use. Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk-Power System [Archive]		5/9/2013		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.
Burden [Archive]		2/8/2005	3/16/2007	Operation of the Bulk Electric System that violates or is expected to violate a System Operating Limit or Interconnection Reliability Operating Limit in the Interconnection, or that violates any other NERC, Regional Reliability Organization, or local operating reliability standards or criteria.
Business Practices [Archive]		8/22/2008	Not approved; Modification directed 11/24/09	Those business rules contained in the Transmission Service Provider’s applicable tariff, rules, or procedures; associated Regional Reliability Organization or regional entity business practices; or NAESB Business Practices.
Bus-tie Breaker [Archive]		8/4/2011		A circuit breaker that is positioned to connect two individual substation bus configurations.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Capacity Benefit Margin [Archive]	CBM	2/8/2005	3/16/2007	The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission Service Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.
Capacity Benefit Margin Implementation Document [Archive]	CBMID	11/13/2008	11/24/2009	A document that describes the implementation of a Capacity Benefit Margin methodology.
Capacity Emergency [Archive]		2/8/2005	3/16/2007	A capacity emergency exists when a Balancing Authority Area's operating capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements.
Cascading [Archive]		2/8/2005	3/16/2007	The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Cascading Outages [Archive]		11/1/2006 Withdrawn 2/12/2008	FERC Remanded 12/27/2007	The uncontrolled successive loss of Bulk Electric System Facilities triggered by an incident (or condition) at any location resulting in the interruption of electric service that cannot be restrained from spreading beyond a pre-determined area.
CIP Exceptional Circumstance [Archive]		11/26/12		A situation that involves or threatens to involve one or more of the following, or similar, conditions that impact safety or BES reliability: a risk of injury or death; a natural disaster; civil unrest; an imminent or existing hardware, software, or equipment failure; a Cyber Security Incident requiring emergency assistance; a response by emergency services; the enactment of a mutual assistance agreement; or an impediment of large scale workforce availability.
CIP Senior Manager [Archive]		11/26/12		A single senior management official with overall authority and responsibility for leading and managing implementation of and continuing adherence to the requirements within the NERC CIP Standards, CIP-002 through CIP-011.
Clock Hour [Archive]		2/8/2005	3/16/2007	The 60-minute period ending at :00. All surveys, measurements, and reports are based on Clock Hour periods unless specifically noted.
Cogeneration [Archive]		2/8/2005	3/16/2007	Production of electricity from steam, heat, or other forms of energy produced as a by-product of another process.
Compliance Monitor [Archive]		2/8/2005	3/16/2007	The entity that monitors, reviews, and ensures compliance of responsible entities with reliability standards.
Confirmed Interchange [Archive]		5/2/2006	3/16/2007	The state where the Interchange Authority has verified the Arranged Interchange.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Congestion Management Report [Archive]		2/8/2005	3/16/2007	A report that the Interchange Distribution Calculator issues when a Reliability Coordinator initiates the Transmission Loading Relief procedure. This report identifies the transactions and native and network load curtailments that must be initiated to achieve the loading relief requested by the initiating Reliability Coordinator.
Consequential Load Loss [Archive]		8/4/2011		All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.
Constrained Facility [Archive]		2/8/2005	3/16/2007	A transmission facility (line, transformer, breaker, etc.) that is approaching, is at, or is beyond its System Operating Limit or Interconnection Reliability Operating Limit.
Contingency [Archive]		2/8/2005	3/16/2007	The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.
Contingency Reserve [Archive]		2/8/2005	3/16/2007	The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.
Contract Path [Archive]		2/8/2005	3/16/2007	An agreed upon electrical path for the continuous flow of electrical power between the parties of an Interchange Transaction.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Control Center [Archive]		11/26/12		One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.
Control Performance Standard [Archive]	CPS	2/8/2005	3/16/2007	The reliability standard that sets the limits of a Balancing Authority's Area Control Error over a specified time period.
Corrective Action Plan [Archive]		2/7/2006	3/16/2007	A list of actions and an associated timetable for implementation to remedy a specific problem.
Cranking Path [Archive]		5/2/2006	3/16/2007	A portion of the electric system that can be isolated and then energized to deliver electric power from a generation source to enable the startup of one or more other generating units.
Critical Assets [Archive]		5/2/2006	1/18/2008	Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System.
Critical Cyber Assets [Archive]		5/2/2006	1/18/2008	Cyber Assets essential to the reliable operation of Critical Assets.
Curtailment [Archive]		2/8/2005	3/16/2007	A reduction in the scheduled capacity or energy delivery of an Interchange Transaction.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Curtailment Threshold [Archive]		2/8/2005	3/16/2007	The minimum Transfer Distribution Factor which, if exceeded, will subject an Interchange Transaction to curtailment to relieve a transmission facility constraint.
Cyber Assets [Archive]		5/2/2006	1/18/2008	Programmable electronic devices and communication networks including hardware, software, and data.
Cyber Assets [Archive]		11/26/12		Programmable electronic devices, including the hardware, software, and data in those devices.
Cyber Security Incident [Archive]		5/2/2006	1/18/2008	Any malicious act or suspicious event that: <ul style="list-style-type: none"> • Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter of a Critical Cyber Asset, or, • Disrupts, or was an attempt to disrupt, the operation of a Critical Cyber Asset.
Cyber Security Incident [Archive]		11/26/12		A malicious act or suspicious event that: <ul style="list-style-type: none"> • Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter or, • Disrupts, or was an attempt to disrupt, the operation of a BES Cyber System.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Delayed Fault Clearing [Archive]		11/1/2006	12/27/2007	Fault clearing consistent with correct operation of a breaker failure protection system and its associated breakers, or of a backup protection system with an intentional time delay.
Demand [Archive]		2/8/2005	3/16/2007	<ol style="list-style-type: none"> 1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.
Demand-Side Management [Archive]	DSM	2/8/2005	3/16/2007	The term for all activities or programs undertaken by Load-Serving Entity or its customers to influence the amount or timing of electricity they use.
Dial-up Connectivity [Archive]		11/26/12		A data communication link that is established when the communication equipment dials a phone number and negotiates a connection with the equipment on the other end of the link.
Direct Control Load Management [Archive]	DCLM	2/8/2005	3/16/2007	Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand.
Dispatch Order [Archive]		08/22/2008	11/24/2009	A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, each generator is ranked by priority.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Dispersed Load by Substations [Archive]		2/8/2005	3/16/2007	Substation load information configured to represent a system for power flow or system dynamics modeling purposes, or both.
Distribution Factor [Archive]	DF	2/8/2005	3/16/2007	The portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate).
Distribution Provider [Archive]	DP	2/8/2005	3/16/2007	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 Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.
Disturbance [Archive]		2/8/2005	3/16/2007	<ol style="list-style-type: none"> 1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.
Disturbance Control Standard [Archive]	DCS	2/8/2005	3/16/2007	The reliability standard that sets the time limit following a Disturbance within which a Balancing Authority must return its Area Control Error to within a specified range.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Disturbance Monitoring Equipment [Archive]	DME	8/2/2006	3/16/2007	<p>Devices capable of monitoring and recording system data pertaining to a Disturbance. Such devices include the following categories of recorders²:</p> <ul style="list-style-type: none"> • Sequence of event recorders which record equipment response to the event • Fault recorders, which record actual waveform data replicating the system primary voltages and currents. This may include protective relays. • Dynamic Disturbance Recorders (DDRs), which record incidents that portray power system behavior during dynamic events such as low-frequency (0.1 Hz – 3 Hz) oscillations and abnormal frequency or voltage excursions
Dynamic Interchange Schedule or Dynamic Schedule [Archive]		2/8/2005	3/16/2007	A telemetered reading or value that is updated in real time and used as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.
Dynamic Transfer [Archive]		2/8/2005	3/16/2007	The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of one Balancing Authority Area into another.

² Phasor Measurement Units and any other equipment that meets the functional requirements of DMEs may qualify as DMEs.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Economic Dispatch [Archive]		2/8/2005	3/16/2007	The allocation of demand to individual generating units on line to effect the most economical production of electricity.
Electronic Access Control or Monitoring Systems [Archive]	EACMS	11/26/12		Cyber Assets that perform electronic access control or electronic access monitoring of the Electronic Security Perimeter(s) or BES Cyber Systems. This includes Intermediate Devices.
Electronic Access Point [Archive]	EAP	11/26/12		A Cyber Asset interface on an Electronic Security Perimeter that allows routable communication between Cyber Assets outside an Electronic Security Perimeter and Cyber Assets inside an Electronic Security Perimeter.
Electrical Energy [Archive]		2/8/2005	3/16/2007	The generation or use of electric power by a device over a period of time, expressed in kilowatthours (kWh), megawatthours (MWh), or gigawatthours (GWh).
Electronic Security Perimeter [Archive]	ESP	5/2/2006	1/18/2008	The logical border surrounding a network to which Critical Cyber Assets are connected and for which access is controlled.
Electronic Security Perimeter [Archive]	ESP	11/26/12		The logical border surrounding a network to which BES Cyber Systems are connected using a routable protocol.
Element [Archive]		2/8/2005	3/16/2007	Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Emergency or BES Emergency [Archive]		2/8/2005	3/16/2007	Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System.
Emergency Rating [Archive]		2/8/2005	3/16/2007	The rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar or other appropriate units, that a system, facility, or element can support, produce, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.
Emergency Request for Interchange [Archive]	Emergency RFI	10/29/2008	12/17/2009	Request for Interchange to be initiated for Emergency or Energy Emergency conditions.
Energy Emergency [Archive]		2/8/2005	3/16/2007	A condition when a Load-Serving Entity has exhausted all other options and can no longer provide its customers' expected energy requirements.
Equipment Rating [Archive]		2/7/2006	3/16/2007	The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady state, short-circuit and transient conditions, as permitted or assigned by the equipment owner.
External Routable Connectivity [Archive]		11/26/12		The ability to access a BES Cyber System from a Cyber Asset that is outside of its associated Electronic Security Perimeter via a bi-directional routable protocol connection.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Existing Transmission Commitments [Archive]	ETC	08/22/2008	11/24/2009	Committed uses of a Transmission Service Provider's Transmission system considered when determining ATC or AFC.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Facility [Archive]		2/7/2006	3/16/2007	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.)
Facility Rating [Archive]		2/8/2005	3/16/2007	The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.
Fault [Archive]		2/8/2005	3/16/2007	An event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection.
Fire Risk [Archive]		2/7/2006	3/16/2007	The likelihood that a fire will ignite or spread in a particular geographic area.
Firm Demand [Archive]		2/8/2005	3/16/2007	That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.
Firm Transmission Service [Archive]		2/8/2005	3/16/2007	The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.
Flashover [Archive]		2/7/2006	3/16/2007	An electrical discharge through air around or over the surface of insulation, between objects of different potential, caused by placing a voltage across the air space that results in the ionization of the air space.
Flowgate [Archive]		2/8/2005	3/16/2007	A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Flowgate [Archive]		08/22/2008	11/24/2009	<p>1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.</p> <p>2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.</p>
Flowgate Methodology [Archive]		08/22/2008	11/24/2009	The Flowgate methodology is characterized by identification of key Facilities as Flowgates. Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. The impacts of Existing Transmission Commitments (ETCs) are determined by simulation. The impacts of ETC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) are subtracted from the Total Flowgate Capability, and Postbacks and counterflows are added, to determine the Available Flowgate Capability (AFC) value for that Flowgate. AFCs can be used to determine Available Transfer Capability (ATC).
Forced Outage [Archive]		2/8/2005	3/16/2007	<p>1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons.</p> <p>2. The condition in which the equipment is unavailable due to unanticipated failure.</p>
Frequency Bias [Archive]		2/8/2005	3/16/2007	A value, usually expressed in megawatts per 0.1 Hertz (MW/0.1 Hz), associated with a Balancing Authority Area that approximates the Balancing Authority Area's response to Interconnection frequency error.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Frequency Bias Setting [Archive]		2/8/2005	3/16/2007	A value, usually expressed in MW/0.1 Hz, set into a Balancing Authority ACE algorithm that allows the Balancing Authority to contribute its frequency response to the Interconnection.
Frequency Bias Setting [Archive]		2/7/2013		A number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority's Area Control Error equation to account for the Balancing Authority's inverse Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems.
Frequency Deviation [Archive]		2/8/2005	3/16/2007	A change in Interconnection frequency.
Frequency Error [Archive]		2/8/2005	3/16/2007	The difference between the actual and scheduled frequency. ($F_A - F_S$)
Frequency Regulation [Archive]		2/8/2005	3/16/2007	The ability of a Balancing Authority to help the Interconnection maintain Scheduled Frequency. This assistance can include both turbine governor response and Automatic Generation Control.
Frequency Response [Archive]		2/8/2005	3/16/2007	(Equipment) The ability of a system or elements of the system to react or respond to a change in system frequency. (System) The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz).

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Frequency Response Measure [Archive]	FRM	2/7/2013		The median of all the Frequency Response observations reported annually by Balancing Authorities or Frequency Response Sharing Groups for frequency events specified by the ERO. This will be calculated as MW/0.1Hz.
Frequency Response Obligation [Archive]	FRO	2/7/2013		The Balancing Authority's share of the required Frequency Response needed for the reliable operation of an Interconnection. This will be calculated as MW/0.1Hz.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Frequency Response Sharing Group [Archive]	FRSG	2/7/2013		A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the sum of the Frequency Response Obligations of its members.
Generator Operator [Archive]	GOP	2/8/2005	3/16/2007	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
Generator Owner [Archive]	GO	2/8/2005	3/16/2007	Entity that owns and maintains generating units.
Generator Shift Factor [Archive]	GSF	2/8/2005	3/16/2007	A factor to be applied to a generator's expected change in output to determine the amount of flow contribution that change in output will impose on an identified transmission facility or Flowgate.
Generator-to-Load Distribution Factor [Archive]	GLDF	2/8/2005	3/16/2007	The algebraic sum of a Generator Shift Factor and a Load Shift Factor to determine the total impact of an Interchange Transaction on an identified transmission facility or Flowgate.
Generation Capability Import Requirement [Archive]	GCIR	11/13/2008	11/24/2009	The amount of generation capability from external sources identified by a Load-Serving Entity (LSE) or Resource Planner (RP) to meet its generation reliability or resource adequacy requirements as an alternative to internal resources.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Host Balancing Authority [Archive]		2/8/2005	3/16/2007	<ol style="list-style-type: none"> 1. A Balancing Authority that confirms and implements Interchange Transactions for a Purchasing Selling Entity that operates generation or serves customers directly within the Balancing Authority's metered boundaries. 2. The Balancing Authority within whose metered boundaries a jointly owned unit is physically located.
Hourly Value [Archive]		2/8/2005	3/16/2007	Data measured on a Clock Hour basis.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Implemented Interchange [Archive]		5/2/2006	3/16/2007	The state where the Balancing Authority enters the Confirmed Interchange into its Area Control Error equation.
Inadvertent Interchange [Archive]		2/8/2005	3/16/2007	The difference between the Balancing Authority's Net Actual Interchange and Net Scheduled Interchange. ($I_A - I_S$)
Independent Power Producer [Archive]	IPP	2/8/2005	3/16/2007	Any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, cogenerators and small power producers and all other nonutility electricity producers, such as exempt wholesale generators, who sell electricity.
Institute of Electrical and Electronics Engineers, Inc. [Archive]	IEEE	2/7/2006	3/16/2007	

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Interactive Remote Access [Archive]		11/26/12		User-initiated access by a person employing a remote access client or other remote access technology using a routable protocol. Remote access originates from a Cyber Asset that is not an Intermediate Device and not located within any of the Responsible Entity's Electronic Security Perimeter(s) or at a defined Electronic Access Point (EAP). Remote access may be initiated from: 1) Cyber Assets used or owned by the Responsible Entity, 2) Cyber Assets used or owned by employees, and 3) Cyber Assets used or owned by vendors, contractors, or consultants. Interactive remote access does not include system-to-system process communications.
Interchange [Archive]		5/2/2006	3/16/2007	Energy transfers that cross Balancing Authority boundaries.
Interchange Authority [Archive]	IA	5/2/2006	3/16/2007	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.
Interchange Distribution Calculator [Archive]	IDC	2/8/2005	3/16/2007	The mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Interchange Schedule [Archive]		2/8/2005	3/16/2007	An agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction.
Interchange Transaction [Archive]		2/8/2005	3/16/2007	An agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries.
Interchange Transaction Tag or Tag [Archive]		2/8/2005	3/16/2007	The details of an Interchange Transaction required for its physical implementation.
Interconnected Operations Service [Archive]		2/8/2005	3/16/2007	A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected Bulk Electric Systems.
Interconnection [Archive]		2/8/2005	3/16/2007	When capitalized, any one of the three major electric system networks in North America: Eastern, Western, and ERCOT.
Interconnection Reliability Operating Limit [Archive]	IROL	2/8/2005	3/16/2007 Retired 12/27/2007	The value (such as MW, MVar, Amperes, Frequency or Volts) derived from, or a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Interconnection Reliability Operating Limit [Archive]	IROL	11/1/2006	12/27/2007	A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages ³ that adversely impact the reliability of the Bulk Electric System.
Interconnection Reliability Operating Limit T _v [Archive]	IROL T _v	11/1/2006	12/27/2007	The maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit's T _v shall be less than or equal to 30 minutes.
Intermediate Balancing Authority [Archive]		2/8/2005	3/16/2007	A Balancing Authority Area that has connecting facilities in the Scheduling Path between the Sending Balancing Authority Area and Receiving Balancing Authority Area and operating agreements that establish the conditions for the use of such facilities.
Intermediate System [Archive]		11/26/12		A Cyber Asset or collection of Cyber Assets performing access control to restrict Interactive Remote Access to only authorized users. The Intermediate System must not be located inside the Electronic Security Perimeter.
Interpersonal Communication [Archive]		11/7/2012		Any medium that allows two or more individuals to interact, consult, or exchange information.

³ On September 13, 2012, FERC issued an Order approving NERC's request to modify the reference to "Cascading Outages" to "Cascading outages" within the definition of IROL due to the fact that the definition of "Cascading Outages" was previously remanded by FERC.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Interruptible Load or Interruptible Demand [Archive]		11/1/2006	3/16/2007	Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.
Joint Control [Archive]		2/8/2005	3/16/2007	Automatic Generation Control of jointly owned units by two or more Balancing Authorities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Limiting Element [Archive]		2/8/2005	3/16/2007	The element that is 1.)Either operating at its appropriate rating, or 2,) Would be following the limiting contingency. Thus, the Limiting Element establishes a system limit.
Load [Archive]		2/8/2005	3/16/2007	An end-use device or customer that receives power from the electric system.
Load Shift Factor [Archive]	LSF	2/8/2005	3/16/2007	A factor to be applied to a load’s expected change in demand to determine the amount of flow contribution that change in demand will impose on an identified transmission facility or monitored Flowgate.
Load-Serving Entity [Archive]	LSE	2/8/2005	3/16/2007	Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.
Long-Term Transmission Planning Horizon [Archive]		8/4/2011		Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.
Market Flow [Archive]		11/4/2010	4/21/2011	The total amount of power flowing across a specified Facility or set of Facilities due to a market dispatch of generation internal to the market to serve load internal to the market.
Minimum Vegetation Clearance Distance [Archive]	MVCD	11/3/2011	3/21/2013 (Becomes effective 7/1/14)	The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Misoperation [Archive]		2/7/2006	3/16/2007	<ul style="list-style-type: none"> Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection. Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone). Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Native Load [Archive]		2/8/2005	3/16/2007	The end-use customers that the Load-Serving Entity is obligated to serve.
Near-Term Transmission Planning Horizon [Archive]		1/24/2011	11/17/2011	The transmission planning period that covers Year One through five.
Net Actual Interchange [Archive]		2/8/2005	3/16/2007	The algebraic sum of all metered interchange over all interconnections between two physically Adjacent Balancing Authority Areas.
Net Energy for Load [Archive]		2/8/2005	3/16/2007	Net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to Balancing Authority Areas through interchange. It includes Balancing Authority Area losses but excludes energy required for storage at energy storage facilities.
Net Interchange Schedule [Archive]		2/8/2005	3/16/2007	The algebraic sum of all Interchange Schedules with each Adjacent Balancing Authority.
Net Scheduled Interchange [Archive]		2/8/2005	3/16/2007	The algebraic sum of all Interchange Schedules across a given path or between Balancing Authorities for a given period or instant in time.
Network Integration Transmission Service [Archive]		2/8/2005	3/16/2007	Service that allows an electric transmission customer to integrate, plan, economically dispatch and regulate its network reserves in a manner comparable to that in which the Transmission Owner serves Native Load customers.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Non-Consequential Load Loss [Archive]		8/4/2011		Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.
Non-Firm Transmission Service [Archive]		2/8/2005	3/16/2007	Transmission service that is reserved on an as-available basis and is subject to curtailment or interruption.
Non-Spinning Reserve [Archive]		2/8/2005	3/16/2007	<ol style="list-style-type: none"> 1. That generating reserve not connected to the system but capable of serving demand within a specified time. 2. Interruptible load that can be removed from the system in a specified time.
Normal Clearing [Archive]		11/1/2006	12/27/2007	A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.
Normal Rating [Archive]		2/8/2005	3/16/2007	The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.
Nuclear Plant Generator Operator [Archive]		5/2/2007	10/16/2008	Any Generator Operator or Generator Owner that is a Nuclear Plant Licensee responsible for operation of a nuclear facility licensed to produce commercial power.
Nuclear Plant Off-site Power Supply (Off-site Power) [Archive]		5/2/2007	10/16/2008	The electric power supply provided from the electric system to the nuclear power plant distribution system as required per the nuclear power plant license.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Nuclear Plant Licensing Requirements [Archive]	NPLRs	5/2/2007	10/16/2008	Requirements included in the design basis of the nuclear plant and statutorily mandated for the operation of the plant, including nuclear power plant licensing requirements for: 1) Off-site power supply to enable safe shutdown of the plant during an electric system or plant event; and 2) Avoiding preventable challenges to nuclear safety as a result of an electric system disturbance, transient, or condition.
Nuclear Plant Interface Requirements [Archive]	NPIRs	5/2/2007	10/16/2008	The requirements based on NPLRs and Bulk Electric System requirements that have been mutually agreed to by the Nuclear Plant Generator Operator and the applicable Transmission Entities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Off-Peak [Archive]		2/8/2005	3/16/2007	Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand.
On-Peak [Archive]		2/8/2005	3/16/2007	Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of higher electrical demand.
Open Access Same Time Information Service [Archive]	OASIS	2/8/2005	3/16/2007	An electronic posting system that the Transmission Service Provider maintains for transmission access data and that allows all transmission customers to view the data simultaneously.
Open Access Transmission Tariff [Archive]	OATT	2/8/2005	3/16/2007	Electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission requiring the Transmission Service Provider to furnish to all shippers with non-discriminating service comparable to that provided by Transmission Owners to themselves.
Operating Plan [Archive]		2/7/2006	3/16/2007	A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Operating Procedure [Archive]		2/7/2006	3/16/2007	A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a system operator to take in removing a specific transmission line from service is an example of an Operating Procedure.
Operating Process [Archive]		2/7/2006	3/16/2007	A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process.
Operating Reserve [Archive]		2/8/2005	3/16/2007	That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.
Operating Reserve – Spinning [Archive]		2/8/2005	3/16/2007	The portion of Operating Reserve consisting of: <ul style="list-style-type: none"> • Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Operating Reserve – Supplemental [Archive]		2/8/2005	3/16/2007	The portion of Operating Reserve consisting of: <ul style="list-style-type: none"> • Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event; or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event.
Operating Voltage [Archive]		2/7/2006	3/16/2007	The voltage level by which an electrical system is designated and to which certain operating characteristics of the system are related; also, the effective (root-mean-square) potential difference between any two conductors or between a conductor and the ground. The actual voltage of the circuit may vary somewhat above or below this value.
Operational Planning Analysis [Archive]		10/17/2008	3/17/2011	An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).
Outage Transfer Distribution Factor [Archive]	OTDF	8/22/2008	11/24/2009	In the post-contingency configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with one or more system Facilities removed from service (outaged).

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Overlap Regulation Service [Archive]		2/8/2005	3/16/2007	A method of providing regulation service in which the Balancing Authority providing the regulation service incorporates another Balancing Authority's actual interchange, frequency response, and schedules into providing Balancing Authority's AGC/ACE equation.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Participation Factors [Archive]		8/22/2008	11/24/2009	A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, generators are assigned a percentage that they will contribute to serve load.
Peak Demand [Archive]		2/8/2005	3/16/2007	<ol style="list-style-type: none"> 1. The highest hourly integrated Net Energy For Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year). 2. The highest instantaneous demand within the Balancing Authority Area.
Performance-Reset Period [Archive]		2/7/2006	3/16/2007	The time period that the entity being assessed must operate without any violations to reset the level of non compliance to zero.
Physical Access Control Systems [Archive]	PACS	11/26/12		Cyber Assets that control, alert, or log access to the Physical Security Perimeter(s), exclusive of locally mounted hardware or devices at the Physical Security Perimeter such as motion sensors, electronic lock control mechanisms, and badge readers.
Physical Security Perimeter [Archive]	PSP	5/2/2006	1/18/2008	The physical, completely enclosed (“six-wall”) border surrounding computer rooms, telecommunications rooms, operations centers, and other locations in which Critical Cyber Assets are housed and for which access is controlled.
Physical Security Perimeter [Archive]	PSP	11/26/12		The physical border surrounding locations in which BES Cyber Assets, BES Cyber Systems, or Electronic Access Control or Monitoring Systems reside, and for which access is controlled.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Planning Assessment [Archive]		8/4/2011		Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies.
Planning Authority [Archive]	PA	2/8/2005	3/16/2007	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
Planning Coordinator [Archive]	PC	8/22/2008	11/24/2009	See Planning Authority.
Point of Delivery [Archive]	POD	2/8/2005	3/16/2007	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction leaves or a Load-Serving Entity receives its energy.
Point of Receipt [Archive]	POR	2/8/2005	3/16/2007	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a Generator delivers its output.
Point to Point Transmission Service [Archive]	PTP	2/8/2005	3/16/2007	The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery.
Postback [Archive]		08/22/2008	Not approved; Modification directed 11/24/09	Positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Power Transfer Distribution Factor [Archive]	PTDF	08/22/2008	11/24/2009	In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system Facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer
Pro Forma Tariff [Archive]		2/8/2005	3/16/2007	Usually refers to the standard OATT and/or associated transmission rights mandated by the U.S. Federal Energy Regulatory Commission Order No. 888.
Protected Cyber Assets [Archive]	PCA	11/26/12		One or more Cyber Assets connected using a routable protocol within or on an Electronic Security Perimeter that is not part of the highest impact BES Cyber System within the same Electronic Security Perimeter. The impact rating of Protected Cyber Assets is equal to the highest rated BES Cyber System in the same ESP. A Cyber Asset is not a Protected Cyber Asset if, for 30 consecutive calendar days or less, it is connected either to a Cyber Asset within the ESP or to the network within the ESP, and it is used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.
Protection System [Archive]		2/7/2006	3/17/2007 retired 4/1/2013	Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Protection System ⁴ [Archive] [Implementation Plan]		11/19/2010	2/3/2012	Protection System – <ul style="list-style-type: none"> • Protective relays which respond to electrical quantities, • Communications systems necessary for correct operation of protective functions • Voltage and current sensing devices providing inputs to protective relays, • Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and • Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

⁴ This term becomes effective on April 1, 2013.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Protection System Maintenance Program [Archive]	PSMP	11/7/2012		<p>An ongoing program by which Protection System components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific component includes one or more of the following activities:</p> <p>Verify — Determine that the component is functioning correctly.</p> <p>Monitor — Observe the routine in-service operation of the component.</p> <p>Test — Apply signals to a component to observe functional performance or output behavior, or to diagnose problems.</p> <p>Inspect — Examine for signs of component failure, reduced performance or degradation.</p> <p>Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.</p>
Pseudo-Tie [Archive]		2/8/2005	3/16/2007	A telemetered reading or value that is updated in real time and used as a “virtual” tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.
Purchasing-Selling Entity [Archive]	PSE	2/8/2005	3/16/2007	The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Ramp Rate or Ramp [Archive]		2/8/2005	3/16/2007	(Schedule) The rate, expressed in megawatts per minute, at which the interchange schedule is attained during the ramp period. (Generator) The rate, expressed in megawatts per minute, that a generator changes its output.
Rated Electrical Operating Conditions [Archive]		2/7/2006	3/16/2007	The specified or reasonably anticipated conditions under which the electrical system or an individual electrical circuit is intend/ designed to operate
Rating [Archive]		2/8/2005	3/16/2007	The operational limits of a transmission system element under a set of specified conditions.
Rated System Path Methodology [Archive]		08/22/2008	11/24/2009	The Rated System Path Methodology is characterized by an initial Total Transfer Capability (TTC), determined via simulation. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from TTC, and Postbacks and counterflows are added as applicable, to derive Available Transfer Capability. Under the Rated System Path Methodology, TTC results are generally reported as specific transmission path capabilities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reactive Power [Archive]		2/8/2005	3/16/2007	The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).
Real Power [Archive]		2/8/2005	3/16/2007	The portion of electricity that supplies energy to the load.
Reallocation [Archive]		2/8/2005	3/16/2007	The total or partial curtailment of Transactions during TLR Level 3a or 5a to allow Transactions using higher priority to be implemented.
Real-time [Archive]		2/7/2006	3/16/2007	Present time as opposed to future time. (From Interconnection Reliability Operating Limits standard.)
Real-time Assessment [Archive]		10/17/2008	3/17/2011	An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data
Receiving Balancing Authority [Archive]		2/8/2005	3/16/2007	The Balancing Authority importing the Interchange.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Regional Reliability Organization [Archive]	RRO	2/8/2005	3/16/2007	<ol style="list-style-type: none"> 1. An entity that ensures that a defined area of the Bulk Electric System is reliable, adequate and secure. 2. A member of the North American Electric Reliability Council. The Regional Reliability Organization can serve as the Compliance Monitor.
Regional Reliability Plan [Archive]		2/8/2005	3/16/2007	The plan that specifies the Reliability Coordinators and Balancing Authorities within the Regional Reliability Organization, and explains how reliability coordination will be accomplished.
Regulating Reserve [Archive]		2/8/2005	3/16/2007	An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.
Regulation Service [Archive]		2/8/2005	3/16/2007	The process whereby one Balancing Authority contracts to provide corrective response to all or a portion of the ACE of another Balancing Authority. The Balancing Authority providing the response assumes the obligation of meeting all applicable control criteria as specified by NERC for itself and the Balancing Authority for which it is providing the Regulation Service.
Reliability Adjustment RFI [Archive]		10/29/2008	12/17/2009	Request to modify an Implemented Interchange Schedule for reliability purposes.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reliability Coordinator [Archive]	RC	2/8/2005	3/16/2007	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric 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 Reliability Coordinator 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.
Reliability Coordinator Area [Archive]		2/8/2005	3/16/2007	The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.
Reliability Coordinator Information System [Archive]	RCIS	2/8/2005	3/16/2007	The system that Reliability Coordinators use to post messages and share operating information in real time.
Reliability Directive [Archive]		8/16/2012		A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impact.
Remedial Action Scheme [Archive]	RAS	2/8/2005	3/16/2007	See “Special Protection System”
Reportable Cyber Security Incident [Archive]		11/26/12		A Cyber Security Incident that has compromised or disrupted one or more reliability tasks of a functional entity.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reliability Standard [Archive]		5/9/2013		A requirement, approved by the United States Federal Energy Regulatory Commission under this Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk-Power System]. The term includes requirements for the operation of existing bulk-power system [Bulk-Power System] facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk-Power System], but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.
Reliable Operation [Archive]		5/9/2013		Operating the elements of the bulk-power system [Bulk-Power System] within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.
Reportable Disturbance [Archive]		2/8/2005	3/16/2007	Any event that causes an ACE change greater than or equal to 80% of a Balancing Authority's or reserve sharing group's most severe contingency. The definition of a reportable disturbance is specified by each Regional Reliability Organization. This definition may not be retroactively adjusted in response to observed performance.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Request for Interchange [Archive]	RFI	5/2/2006	3/16/2007	A collection of data as defined in the NAESB RFI Datasheet, to be submitted to the Interchange Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority.
Reserve Sharing Group [Archive]	RSG	2/8/2005	3/16/2007	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority 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 Reserve Sharing Group.
Resource Planner [Archive]	RP	2/8/2005	3/16/2007	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 Planning Authority Area.
Response Rate [Archive]		2/8/2005	3/16/2007	The Ramp Rate that a generating unit can achieve under normal operating conditions expressed in megawatts per minute (MW/Min).
Right-of-Way [Archive]	ROW	2/7/2006	3/16/2007	A corridor of land on which electric lines may be located. The Transmission Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Right-of-Way [Archive]	ROW	11/3/2011	3/21/2013 (Becomes inactive 6/30/14)	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.
Right-of-Way [Archive]	ROW	5/9/12	(Becomes effective 7/1/14)	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.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Scenario [Archive]		2/7/2006	3/16/2007	Possible event.
Schedule [Archive]		2/8/2005	3/16/2007	(Verb) To set up a plan or arrangement for an Interchange Transaction. (Noun) An Interchange Schedule.
Scheduled Frequency [Archive]		2/8/2005	3/16/2007	60.0 Hertz, except during a time correction.
Scheduling Entity [Archive]		2/8/2005	3/16/2007	An entity responsible for approving and implementing Interchange Schedules.
Scheduling Path [Archive]		2/8/2005	3/16/2007	The Transmission Service arrangements reserved by the Purchasing-Selling Entity for a Transaction.
Sending Balancing Authority [Archive]		2/8/2005	3/16/2007	The Balancing Authority exporting the Interchange.
Sink Balancing Authority [Archive]		2/8/2005	3/16/2007	The Balancing Authority in which the load (sink) is located for an Interchange Transaction. (This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)
Source Balancing Authority [Archive]		2/8/2005	3/16/2007	The Balancing Authority in which the generation (source) is located for an Interchange Transaction. (This will also be a Sending Balancing Authority for the resulting Interchange Schedule.)

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Special Protection System (Remedial Action Scheme) [Archive]	SPS	2/8/2005	3/16/2007	An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.
Spinning Reserve [Archive]		2/8/2005	3/16/2007	Unloaded generation that is synchronized and ready to serve additional demand.
Stability [Archive]		2/8/2005	3/16/2007	The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances.
Stability Limit [Archive]		2/8/2005	3/16/2007	The maximum power flow possible through some particular point in the system while maintaining stability in the entire system or the part of the system to which the stability limit refers.
Supervisory Control and Data Acquisition [Archive]	SCADA	2/8/2005	3/16/2007	A system of remote control and telemetry used to monitor and control the transmission system.
Supplemental Regulation Service [Archive]		2/8/2005	3/16/2007	A method of providing regulation service in which the Balancing Authority providing the regulation service receives a signal representing all or a portion of the other Balancing Authority's ACE.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Surge [Archive]		2/8/2005	3/16/2007	A transient variation of current, voltage, or power flow in an electric circuit or across an electric system.
Sustained Outage [Archive]		2/7/2006	3/16/2007	The deenergized condition of a transmission line resulting from a fault or disturbance following an unsuccessful automatic reclosing sequence and/or unsuccessful manual reclosing procedure.
System [Archive]		2/8/2005	3/16/2007	A combination of generation, transmission, and distribution components.
System Operating Limit [Archive]	SOL	2/8/2005	3/16/2007	The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: <ul style="list-style-type: none"> • Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings) • Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits) • Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability) • System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)
System Operator [Archive]		2/8/2005	3/16/2007	An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Telemetry [Archive]		2/8/2005	3/16/2007	The process by which measurable electrical quantities from substations and generating stations are instantaneously transmitted to the control center, and by which operating commands from the control center are transmitted to the substations and generating stations.
Thermal Rating [Archive]		2/8/2005	3/16/2007	The maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it sags to the point that it violates public safety requirements.
Tie Line [Archive]		2/8/2005	3/16/2007	A circuit connecting two Balancing Authority Areas.
Tie Line Bias [Archive]		2/8/2005	3/16/2007	A mode of Automatic Generation Control that allows the Balancing Authority to 1.) maintain its Interchange Schedule and 2.) respond to Interconnection frequency error.
Time Error [Archive]		2/8/2005	3/16/2007	The difference between the Interconnection time measured at the Balancing Authority(ies) and the time specified by the National Institute of Standards and Technology. Time error is caused by the accumulation of Frequency Error over a given period.
Time Error Correction [Archive]		2/8/2005	3/16/2007	An offset to the Interconnection's scheduled frequency to return the Interconnection's Time Error to a predetermined value.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
TLR Log [Archive]		2/8/2005	3/16/2007	Report required to be filed after every TLR Level 2 or higher in a specified format. The NERC IDC prepares the report for review by the issuing Reliability Coordinator. After approval by the issuing Reliability Coordinator, the report is electronically filed in a public area of the NERC Web site.
Total Flowgate Capability [Archive]	TFC	08/22/2008	11/24/2009	The maximum flow capability on a Flowgate, is not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), is not to exceed the associated System Operating Limit.
Total Transfer Capability [Archive]	TTC	2/8/2005	3/16/2007	The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.
Transaction [Archive]		2/8/2005	3/16/2007	See Interchange Transaction.
Transfer Capability [Archive]		2/8/2005	3/16/2007	The measure of the ability of interconnected electric systems to move or transfer power <i>in a reliable manner</i> from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from "Area A" to "Area B" is <i>not</i> generally equal to the transfer capability from "Area B" to "Area A."

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Transfer Distribution Factor [Archive]		2/8/2005	3/16/2007	See Distribution Factor.
Transmission [Archive]		2/8/2005	3/16/2007	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.
Transmission Constraint [Archive]		2/8/2005	3/16/2007	A limitation on one or more transmission elements that may be reached during normal or contingency system operations.
Transmission Customer [Archive]		2/8/2005	3/16/2007	<ol style="list-style-type: none"> 1. Any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service. 2. Any of the following responsible entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.
Transmission Line [Archive]		2/7/2006	3/16/2007	A system of structures, wires, insulators and associated hardware that carry electric energy from one point to another in an electric power system. Lines are operated at relatively high voltages varying from 69 kV up to 765 kV, and are capable of transmitting large quantities of electricity over long distances.
Transmission Operator [Archive]	TOP	2/8/2005	3/16/2007	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Transmission Operator Area [Archive]		08/22/2008	11/24/2009	The collection of Transmission assets over which the Transmission Operator is responsible for operating.
Transmission Owner [Archive]	TO	2/8/2005	3/16/2007	The entity that owns and maintains transmission facilities.
Transmission Planner [Archive]	TP	2/8/2005	3/16/2007	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 Planning Authority Area.
Transmission Reliability Margin [Archive]	TRM	2/8/2005	3/16/2007	The amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.
Transmission Reliability Margin Implementation Document [Archive]	TRMID	08/22/2008	11/24/2009	A document that describes the implementation of a Transmission Reliability Margin methodology, and provides information related to a Transmission Operator's calculation of TRM.
Transmission Service [Archive]		2/8/2005	3/16/2007	Services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.
Transmission Service Provider [Archive]	TSP	2/8/2005	3/16/2007	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Vegetation [Archive]		2/7/2006	3/16/2007	All plant material, growing or not, living or dead.
Vegetation Inspection [Archive]		2/7/2006	3/16/2007	The systematic examination of a transmission corridor to document vegetation conditions.
Vegetation Inspection [Archive]		11/3/2011	3/21/2013 (Becomes inactive 6/30/14)	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.
Vegetation Inspection [Archive]		5/9/12	(Becomes effective 7/1/14)	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.
Wide Area [Archive]		2/8/2005	3/16/2007	The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.
Year One [Archive]		1/24/2011	11/17/2011	The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For an assessment started in a given calendar year, Year One includes the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One includes the forecasted peak Load period for either 2012 or 2013.

ReliabilityFirst Regional Definitions

The following definitions were developed for use in ReliabilityFirst Regional Standards.

RFC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Resource Adequacy [Archive]		08/05/2009	03/17/2011	The ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses)
Net Internal Demand [Archive]		08/05/2009	03/17/2011	Total of all end-use customer demand and electric system losses within specified metered boundaries, less Direct Control Management and Interruptible Demand
Peak Period [Archive]		08/05/2009	03/17/2011	A period consisting of two (2) or more calendar months but less than seven (7) calendar months, which includes the period during which the responsible entity's annual peak demand is expected to occur
Wind Generating Station [Archive]		11/03/2011		A collection of wind turbines electrically connected together and injecting energy into the grid at one point, sometimes known as a "Wind Farm."
Year One [Archive]		08/05/2009	03/17/2011	The planning year that begins with the upcoming annual Peak Period

NPCC Regional Definitions

The following definitions were developed for use in NPCC Regional Standards.

NPCC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Current Zero Time [Archive]		11/04/2010	10/20/2011	The time of the final current zero on the last phase to interrupt.
Generating Plant [Archive]		11/04/2010	10/20/2011	One or more generators at a single physical location whereby any single contingency can affect all the generators at that location.

WECC Regional Definitions

The following definitions were developed for use in WECC Regional Standards.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Area Control Error [†] [Archive]	ACE	3/12/2007	6/8/2007	Means the instantaneous difference between net actual and scheduled interchange, taking into account the effects of Frequency Bias including correction for meter error.
Automatic Generation Control [†] [Archive]	AGC	3/12/2007	6/8/2007	Means equipment that automatically adjusts a Control Area's generation from a central location to maintain its interchange schedule plus Frequency Bias.
Automatic Time Error Correction [Archive]		3/26/2008	5/21/2009	A frequency control automatic action that a Balancing Authority uses to offset its frequency contribution to support the Interconnection's scheduled frequency.
Automatic Time Error Correction [Archive]		12/19/2012		The addition of a component to the ACE equation that modifies the control point for the purpose of continuously paying back Primary Inadvertent Interchange to correct accumulated time error.
Average Generation [†] [Archive]		3/12/2007	6/8/2007	Means the total MWh generated within the Balancing Authority Operator's Balancing Authority Area during the prior year divided by 8760 hours (8784 hours if the prior year had 366 days).
Business Day [†] [Archive]		3/12/2007	6/8/2007	Means any day other than Saturday, Sunday, or a legal public holiday as designated in section 6103 of title 5, U.S. Code.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Commercial Operation [Archive]		10/29/2008	4/21/2011	Achievement of this designation indicates that the Generator Operator or Transmission Operator of the synchronous generator or synchronous condenser has received all approvals necessary for operation after completion of initial start-up testing.
Contributing Schedule [Archive]		2/10/2009	3/17/2011	A Schedule not on the Qualified Transfer Path between a Source Balancing Authority and a Sink Balancing Authority that contributes unscheduled flow across the Qualified Transfer Path.
Dependability-Based Misoperation [Archive]		10/29/2008	4/21/2011	Is the absence of a Protection System or RAS operation when intended. Dependability is a component of reliability and is the measure of a device's certainty to operate when required.
Disturbance [†] [Archive]		3/12/2007	6/8/2007	Means (i) any perturbation to the electric system, or (ii) the unexpected change in ACE that is caused by the sudden loss of generation or interruption of load.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Extraordinary Contingency [†] [Archive]		3/12/2007	6/8/2007	Shall have the meaning set out in Excuse of Performance, section B.4.c. language in section B.4.c: <i>means any act of God, actions by a non-affiliated third party, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, earthquake, explosion, accident to or breakage, failure or malfunction of machinery or equipment, or any other cause beyond the Reliability Entity's reasonable control; provided that prudent industry standards (e.g. maintenance, design, operation) have been employed; and provided further that no act or cause shall be considered an Extraordinary Contingency if such act or cause results in any contingency contemplated in any WECC Reliability Standard (e.g., the "Most Severe Single Contingency" as defined in the WECC Reliability Criteria or any lesser contingency).</i>
Frequency Bias [†] [Archive]		3/12/2007	6/8/2007	Means a value, usually given in megawatts per 0.1 Hertz, associated with a Control Area that relates the difference between scheduled and actual frequency to the amount of generation required to correct the difference.
Functionally Equivalent Protection System [Archive]	FEPS	10/29/2008	4/21/2011	A Protection System that provides performance as follows: <ul style="list-style-type: none"> • Each Protection System can detect the same faults within the zone of protection and provide the clearing times and coordination needed to comply with all Reliability Standards. • Each Protection System may have different components and operating characteristics.
Functionally Equivalent RAS [Archive]	FERAS	10/29/2008	4/21/2011	A Remedial Action Scheme ("RAS") that provides the same performance as follows: <ul style="list-style-type: none"> • Each RAS can detect the same conditions and provide

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
				mitigation to comply with all Reliability Standards. <ul style="list-style-type: none"> • Each RAS may have different components and operating characteristics.
Generating Unit Capability [†] [Archive]		3/12/2007	6/8/2007	Means the MVA nameplate rating of a generator.
Non-spinning Reserve [†] [Archive]		3/12/2007	6/8/2007	Means that Operating Reserve not connected to the system but capable of serving demand within a specified time, or interruptible load that can be removed from the system in a specified time.
Normal Path Rating [†] [Archive]		3/12/2007	6/8/2007	Is the maximum path rating in MW that has been demonstrated to WECC through study results or actual operation, whichever is greater. For a path with transfer capability limits that vary seasonally, it is the maximum of all the seasonal values.
Operating Reserve [†] [Archive]		3/12/2007	6/8/2007	Means that capability above firm system demand required to provide for regulation, load-forecasting error, equipment forced and scheduled outages and local area protection. Operating Reserve consists of Spinning Reserve and Nonspinning Reserve.
Operating Transfer Capability Limit [†] [Archive]	OTC	3/12/2007	6/8/2007	Means the maximum value of the most critical system operating parameter(s) which meets: (a) precontingency criteria as determined by equipment loading capability and acceptable voltage conditions, (b) transient criteria as determined by equipment loading capability and acceptable voltage conditions, (c) transient performance criteria, and (d) post-contingency loading and voltage criteria.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Primary Inadvertent Interchange [Archive]		3/26/2008	5/21/2009	The component of area (n) inadvertent interchange caused by the regulating deficiencies of the area (n).
Qualified Controllable Device [Archive]		2/10/2009	3/17/2011	A controllable device installed in the Interconnection for controlling energy flow and the WECC Operating Committee has approved using the device for controlling the USF on the Qualified Transfer Paths.
Qualified Transfer Path [Archive]		2/10/2009	3/17/2011	A transfer path designated by the WECC Operating Committee as being qualified for WECC unscheduled flow mitigation.
Qualified Transfer Path Curtailment Event [Archive]		2/10/2009	3/17/2011	Each hour that a Transmission Operator calls for Step 4 or higher for one or more consecutive hours (See Attachment 1 IRO-006-WECC-1) during which the curtailment tool is functional.
Relief Requirement [Archive]		2/10/2009	3/17/2011	The expected amount of the unscheduled flow reduction on the Qualified Transfer Path that would result by curtailing each Sink Balancing Authority's Contributing Schedules by the percentages listed in the columns of WECC Unscheduled Flow Mitigation Summary of Actions Table in Attachment 1 WECC IRO-006-WECC-1.
Secondary Inadvertent Interchange [Archive]		3/26/2008	5/21/2009	The component of area (n) inadvertent interchange caused by the regulating deficiencies of area (i).
Security-Based Misoperation		10/29/2008	4/21/2011	A Misoperation caused by the incorrect operation of a Protection System or RAS. Security is a component of reliability

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
[Archive]				and is the measure of a device’s certainty not to operate falsely.
Spinning Reserve [†] [Archive]		3/12/2007	6/8/2007	Means unloaded generation which is synchronized and ready to serve additional demand. It consists of Regulating reserve and Contingency reserve (as each are described in Sections B.a.i and ii).
Transfer Distribution Factor [Archive]	TDF	2/10/2009	3/17/2011	The percentage of USF that flows across a Qualified Transfer Path when an Interchange Transaction (Contributing Schedule) is implemented. [See the WECC Unscheduled Flow Mitigation Summary of Actions Table (Attachment 1 WECC IRO-006-WECC-1).]
WECC Table 2 [†] [Archive]		3/12/2007	6/8/2007	Means the table maintained by the WECC identifying those transfer paths monitored by the WECC regional Reliability coordinators. As of the date set out therein, the transmission paths identified in Table 2 are as listed in Attachment A to this Standard.

Endnotes

[†] FERC approved the WECC Tier One Reliability Standards in the Order Approving Regional Reliability Standards for the Western Interconnection and Directing Modifications, 119 FERC ¶ 61,260 (June 8, 2007). In that Order, FERC directed WECC to address the inconsistencies between the regional definitions and the NERC Glossary in developing permanent replacement standards. The replacement standards designed to address the shortcomings were filed with FERC in 2009.

Exhibit C

**Informational Summary of Each Reliability Standard Applicable to Nova Scotia,
Approved by FERC in First Quarter 2013**

EXHIBIT C: Informational Summary of Reliability Standard Applicable to Nova Scotia, Approved by FERC in First Quarter 2013

PRC-006-NPCC-01 - To provide a regional reliability standard that ensures the development of an effective automatic underfrequency load shedding (“UFLS”) program in order to preserve the security and integrity of the bulk power system during declining system frequency events in coordination with the NERC UFLS reliability standard characteristics.

Applicability:

- Generator Owner
- Planning Coordinator
- Distribution Provider
- Transmission Owner

On November 21, 2011, NPCC submitted the proposed regional Reliability Standard to NERC for evaluation and approval. NERC submitted the standard to the Federal Energy Regulatory Commission (“FERC”) on May 4, 2012, and on February 21, 2013, FERC approved the standard.

EXHIBIT C: Informational Summary of Reliability Standard Applicable to Nova Scotia, Approved by FERC in First Quarter 2013

FAC-003-2 - 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.

Applicability:

- Transmission Owners.

NERC submitted FAC-003-2 to the Federal Energy Regulatory Commission (“FERC”) on December 21, 2011, and it was approved by FERC on March 21, 2013.