Exhibit A

Proposed Reliability Standard FAC-003-4

FAC-003-4 Clean Version

A. Introduction

1. **Title:** **Transmission Vegetation Management**

2. **Number:** **FAC-003-4**

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

4. **Applicability:**

4.1. Functional Entities:

4.1.1. Applicable Transmission Owners

4.1.1.1. Transmission Owners that own Transmission Facilities defined in 4.2.

4.1.2. Applicable Generator Owners

4.1.2.1. Generator Owners that own generation Facilities defined in 4.3.

4.2. Transmission Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities:

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

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

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

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

4.3. Generation Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[2], state, provincial, public, private, or tribal entities:

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies."*

[2] *Id.*

4.3.1. Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) do not have a clear line of sight[3] from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and are:

4.3.1.1. Operated at 200kV or higher; or

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

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

5. **Effective Date:** See Implementation Plan

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

a) Performance-based defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome?*

b) Risk-based preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?*

c) Competency-based defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?*

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

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

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

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

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

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

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

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

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

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

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

B. Requirements and Measures

R1. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below[4] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:

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

1.1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,[5]

1.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[6]

1.3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[7],

1.4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.[8]

M1. Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

R2. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[9] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:

2.1. An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage,[10]

2.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[11]

2.3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,[12]

2.4. An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage.[13]

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

[6] 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.

[7] *Id.*

[8] *Id.*

[9] See footnote 4.

[10] See footnote 5.

[11] See footnote 6.

[12] *Id.*

[13] *Id.*

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

R3. Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]:*

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.

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

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

M4. Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

R5. When an applicable Transmission Owner and an applicable Generator Owner are constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M5. Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

R6. Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW[14] [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M6. Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

R7. Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.). Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

7.1. Change in expected growth rate/environmental factors

7.2. Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner[15]

7.3. Rescheduling work between growing seasons

7.4. Crew or contractor availability/Mutual assistance agreements

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

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

7.5. Identified unanticipated high priority work

7.6. Weather conditions/Accessibility

7.7. Permitting delays

7.8. Land ownership changes/Change in land use by the landowner

7.9. Emerging technologies

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

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

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

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

- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, for three calendar years.
- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

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

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information

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

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

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

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

- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

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

Violation Severity Levels (Table 1)

R #	Table 1: Violation Severity Levels (VSL)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following: • *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.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of

			an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following: • *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*
R3.		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity's applicable lines. (Requirement R3, Part 3.2.)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines. (Requirement R3, Part 3.1.)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity's applicable lines.
R4.			The responsible entity experienced a confirmed	The responsible entity experienced a confirmed

			vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5.				The responsible entity did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6.	The responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7.	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Variances

None.

E. Associated Documents

- FAC-003-4 Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	January 20, 2006	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.	New
1	April 4, 2007	Regulatory Approval - Effective Date	New
2	November 3, 2011	Adopted by the NERC Board of Trustees	New
2	March 21, 2013	FERC Order issued approving FAC-003-2 (Order No. 777) FERC Order No. 777 was issued on March 21, 2013 directing NERC to "conduct or contract testing to obtain empirical data and submit a report to the Commission providing the results of the testing."[16]	Revisions

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

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.”	Revisions
3	May 9, 2013	FAC-003-3 adopted by Board of Trustees	Revisions
3	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-003-3. This standard became enforceable on July 1, 2014 for Transmission Owners. For Generator Owners, R3 became enforceable on January 1, 2015 and all other requirements (R1, R2, R4, R5, R6, and R7) became enforceable on January 1, 2016.	Revisions
3	November 22, 2013	Updated the VRF for R2 from “Medium” to “High” per a Final Rule issued by FERC	Revisions
3	July 30, 2014	Transferred the effective dates section from FAC-003-2 (for Transmission Owners) into FAC-003-3, per the FAC-003-3 implementation plan	Revisions
4	February 11, 2016	Adopted by Board of Trustees. Adjusted MVCD values in Table 2 for alternating current systems, consistent with findings reported in report filed on August 12, 2015 in Docket No. RM12-4-002 consistent with FERC’s directive in Order No. 777, and based on empirical testing results for flashover distances between conductors and vegetation.	Revisions
4	March 9, 2016	Corrected subpart 7.10 to M7, corrected value of .07 to .7	Errata

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[17]

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)[+]	(AC) Maximum System Voltage (kV)[18]	MVCD (feet) Over sea level up to 500 ft	MVCD feet Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft	MVCD feet Over 11000 ft up to 12000 ft	MVCD feet Over 12000 ft up to 13000 ft	MVCD feet Over 13000 ft up to 14000 ft	MVCD feet Over 14000 ft up to 15000 ft
765	800	11.6ft	11.7ft	11.9ft	12.1ft	12.2ft	12.4ft	12.6ft	12.8ft	13.0ft	13.1ft	13.3ft	13.5ft	13.7ft	13.9ft	14.1ft	14.3ft
500	550	7.0ft	7.1ft	7.2ft	7.4ft	7.5ft	7.6ft	7.8ft	7.9ft	8.1ft	8.2ft	8.3ft	8.5ft	8.6ft	8.8ft	8.9ft	9.1ft
345	362[19]	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft
287	302	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft	5.8ft	5.9ft	6.1ft	6.2ft	6.3ft	6.4ft	6.5ft	6.6ft	6.8ft	6.9ft
230	242	4.0ft	4.1ft	4.2ft	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft
161*	169	2.7ft	2.7ft	2.8ft	2.9ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft	3.3ft	3.3ft	3.4ft	3.5ft	3.6ft	3.7ft	3.8ft
138*	145	2.3ft	2.3ft	2.4ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft	2.7ft	2.8ft	2.8ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft
115*	121	1.9ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.1ft	2.2ft	2.2ft	2.3ft	2.3ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft
88*	100	1.5ft	1.5ft	1.6ft	1.6ft	1.7ft	1.7ft	1.8ft	1.8ft	1.8ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.2ft	2.2ft
69*	72	1.1ft	1.1ft	1.1ft	1.2ft	1.2ft	1.2ft	1.2ft	1.3ft	1.3ft	1.3ft	1.4ft	1.4ft	1.4ft	1.5ft	1.6ft	1.6ft

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

[+] *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)*

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[17] 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.

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

[19] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the Supplemental Materials for additional information.

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[20]

For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)[+]	(AC) Maximum System Voltage (kV)[21]	MVCD meters Over sea level up to 153 m	MVCD meters Over 153m up to 305m	MVCD meters Over 305m up to 610m	MVCD meters Over 610m up to 915m	MVCD meters Over 915m up to 1220m	MVCD meters Over 1220m up to 1524m	MVCD meters Over 1524m up to 1829m	MVCD meters Over 1829m up to 2134m	MVCD meters Over 2134m up to 2439m	MVCD meters Over 2439m up to 2744m	MVCD meters Over 2744m up to 3048m	MVCD meters Over 3048m up to 3353m	MVCD meters Over 3353m up to 3657m	MVCD meters Over 3657m up to 3962m	MVCD meters Over 3962 m up to 4268 m	MVCD meters Over 4268m up to 4572m
765	800	3.6m	3.6m	3.6m	3.7m	3.7m	3.8m	3.8m	3.9m	4.0m	4.0m	4.1m	4.1m	4.2m	4.2m	4.3m	4.4m
500	550	2.1m	2.2m	2.2m	2.3m	2.3m	2.3m	2.4m	2.4m	2.5m	2..5m	2.5m	2.6m	2.6m	2.7m	2.7m	2.7m
345	362[22]	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m	1.7m	1.7m	1.8m
287	302	1.6m	1.6m	1.7m	1.7m	1.7m	1.7m	1.8m	1.8m	1.9m	1.9m	1.9m	2.0m	2.0m	2.0m	2.1m	2.1m
230	242	1.2m	1.3m	1.3m	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m
161*	169	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m	1.0m	1.0m	1.0m	1.1m	1.1m	1.1m	1.1m
138*	145	0.7m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m
115*	121	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.8m
88*	100	0.4m	0.4m	0.5m	0.5m	0.5m	0.5m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m
69*	72	0.3m	0.3m	0.3m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.5m	0.5m	0.5m

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

[+] *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)*

[20] 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.

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

[22] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the supplemental materials for additional information.

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[23]

For **Direct Current** Voltages feet (meters)

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

[23] 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.

Guideline and Technical Basis

Effective dates:

The Compliance section is standard language used in most NERC standards to cover the general effective date and covers the vast majority of situations. A special case covers effective dates for (1) lines initially becoming subject to the Standard, (2) lines changing in applicability within the standard.

The special case 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 2015 may identify a line to have that designation beginning in PY 2025, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. 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.

Date that Planning Study is completed	PY the line will become an IROL element	Date 1	Date 2	Effective Date The later of Date 1 or Date 2
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

Defined Terms:

Explanation for revising the definition of ROW:
The current NERC glossary definition of Right of Way has been modified to include Generator Owners and to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This 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 current 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 Inspection:
The current glossary definition of this NERC term was modified to include Generator Owners and to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

Explanation of the derivation of the MVCD:
The MVCD is a calculated minimum distance that is derived from the Gallet equation. 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 of the Standard provides MVCD values for various voltages and altitudes. The table is based on empirical testing data from EPRI as requested by FERC in Order No. 777.

Project 2010-07.1 Adjusted MVCDs per EPRI Testing:
In Order No. 777, FERC directed NERC to undertake testing to gather empirical data validating the appropriate gap factor used in the Gallet equation to calculate MVCDs, specifically the gap factor for the flash-over distances between conductors and vegetation. See, Order No. 777, at P 60. NERC engaged industry through a collaborative research project and contracted EPRI to complete the scope of work. In January 2014, NERC formed an advisory group to assist with developing the scope of work for the project. This team provided subject matter expertise for developing the test plan, monitoring testing, and vetting the analysis and conclusions to be submitted in a final report. The advisory team was comprised of NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulation coordination, and vegetation management. The testing project commenced in April 2014 and continued through October 2014 with the final set of testing completed in May 2015. Based on these testing results conducted by EPRI, and consistent with the report filed in FERC Docket No. RM12-4-000, the gap factor used in the Gallet equation required adjustment from 1.3 to 1.0. This resulted in increased MVCD values for all alternating current system voltages identified. The adjusted MVCD values, reflecting the 1.0 gap factor, are included in Table 2 of version 4 of FAC-003.

The air gap testing completed by EPRI per FERC Order No. 777 established that trees with large spreading canopies growing directly below energized high voltage conductors create the

greatest likelihood of an air gap flash over incident and was a key driver in changing the gap factor to a more conservative value of 1.0 in version 4 of this standard.

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

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant.

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

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

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's

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

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

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

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

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

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

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated*

2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

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

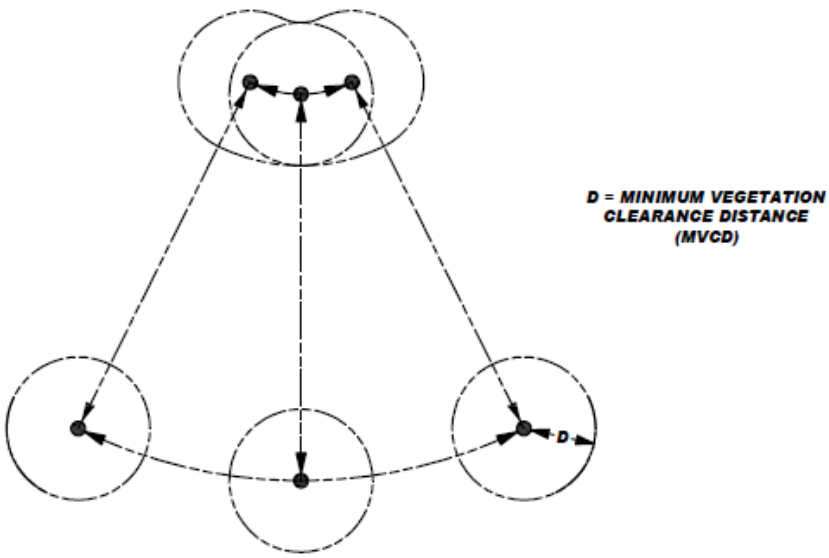

Figure 1

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

Requirement R4:

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

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

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

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

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

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

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

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of herbicides to control incompatible vegetation outside of the MVCD, but agree to the use of mechanical clearing. In

this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

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

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

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

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

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable

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

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

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

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

other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

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

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

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 used 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-003-1 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 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 was approximately 2.0 per unit. This value was 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 was 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 was 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.

Since no empirical data for spark over distances to live vegetation existed at the time version 3 was developed, the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

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

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

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

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

Rationale for Applicability (section 4.2.4):
The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows:

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

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

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

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

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

Rationale for R3:
The documentation provides a basis for evaluating the competency of the applicable Transmission Owner’s or applicable Generator Owner’s vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the

applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions.

Rationale for R4:

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

Rationale for R5:

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

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

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

Rationale for R6:

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

Rationale for R7:

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

FAC-003-4 Redline Version

~~Effective Dates~~

~~Generator Owners~~

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

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

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

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

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

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

~~1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.~~

~~2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.~~

~~3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.~~

~~4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.~~

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

~~**Transmission Owners** [transferred from FAC-003-2]~~

~~This standard becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval is required. Where no regulatory approval is required, the standard becomes effective on the first calendar day of the first calendar quarter one year after Board of Trustees adoption.~~

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

1. ~~A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC transfer Path.~~

2. ~~A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.~~

3. ~~A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.~~

4. ~~An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard, becomes subject to this standard 12 months after the acquisition date.~~

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

A. Introduction

1. **Title:** **Transmission Vegetation Management**

2. **Number:** **FAC-003-~~3~~4**

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

4. **Applicability:**

4.1. Functional Entities:

4.1.1. Applicable Transmission Owners

4.1.1.1. Transmission Owners that own Transmission Facilities defined in 4.2.

4.1.2. Applicable Generator Owners

4.1.2.1. Generator Owners that own generation Facilities defined in 4.3.

4.2. Transmission Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[1], 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.

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies."*

4.3. Generation Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[2], state, provincial, public, private, or tribal entities:

4.3.1. Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) do not have a clear line of sight[3] from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and are:

4.3.1.1. Operated at 200kV or higher; or

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

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

~~Enforcement:~~

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

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

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

[2] *Id.*

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

~~The "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."~~

~~4. Background:~~

5. Effective Date: See Implementation Plan

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

a) Performance-based defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome?*

b) Risk-based preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?*

c) Competency-based defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?*

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

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

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);

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

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

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

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

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

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

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

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

such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

B. Requirements and Measures

R1. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the ~~MVCD~~Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below[4] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:

1.1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,[5]

1.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[6]

1.3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[7],

1.4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.[8]

M1. Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

R2. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path;

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

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

[6] 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.

[7] *Id.*

[8] *Id.*

operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[9] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:

2.1. An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage,[10]

2.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[11]

2.3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,[12]

2.4. An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage.[13]

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

R3. Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following: -*[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]:*

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

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

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

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

[9] See footnote 4.
[10] See footnote 5.
[11] See footnote 6.
[12] *Id.*
[13] *Id.*

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

M4. Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

R5. When ~~a~~an applicable Transmission Owner and an applicable Generator Owner ~~is~~are constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M5. Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

R6. Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW[14] [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M6. Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all

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

applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

R7. Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.). Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

7.1. Change in expected growth rate/-environmental factors

7.2. Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner[15]

7.3. Rescheduling work between growing seasons

7.4. Crew or contractor availability/-Mutual assistance agreements

7.5. Identified unanticipated high priority work

7.6. Weather conditions/Accessibility

7.7. Permitting delays

7.8. Land ownership changes/Change in land use by the landowner

7.9. Emerging technologies

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

C. Compliance

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

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

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

~~For NERC, a third-party monitor without vested interest in the outcome for NERC shall serve as the Compliance Enforcement~~an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

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

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

- The applicable Transmission Owner and applicable Generator Owner 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~~for three calendar years.
- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- If ~~a~~an applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

1.3. ~~The~~ Compliance Monitoring and Enforcement ~~Authority shall keep~~Program

As defined in the ~~last audit records and all requested and submitted subsequent audit records.~~

NERC Rules of Procedure, "Compliance Monitoring and Enforcement ~~**Processes:**~~Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

~~**2.** Compliance Audit~~

~~**3.** Self-Certification~~

~~**4.** Spot Checking~~

~~**5.** Compliance Violation Investigation~~

~~**6.** Self-Reporting~~

~~Complaint~~

~~Periodic Data Submittal~~

~~6.1.~~1.4. Additional Compliance Information

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

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

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

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

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

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

Violation Severity Levels (Table ~~of Compliance Elements~~1)

R #	~~Time Horizon~~	~~VRF~~	Table 1: Violation Severity ~~Level~~Levels (VSL)				
			Lower VSL	Moderate VSL		High VSL	Severe VSL
R1.			~~Real-time~~	~~High~~		The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following: • *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~~			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line 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: • *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*
R3.	~~Long Term Planning~~	~~Lower~~		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications

				growth rates, vegetation control methods, and inspection frequency, for the responsible entity's applicable lines. (Requirement R3, Part 3.2~~)~~.)			Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines. (Requirement R3, Part 3.1~~)~~.)			used to prevent the encroachment of vegetation into the MVCD, for the responsible entity's applicable lines.
R4.	~~Real-time~~			~~Medium~~			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.			The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5.	~~Operations Planning~~			~~Medium~~						The responsible entity did not take corrective action when it was constrained from performing planned vegetation work where an

								applicable line was put at potential risk.
R6.	~~Operations Planning~~	~~Medium~~	The responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).			The responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7.	~~Operations Planning~~	~~Medium~~	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).			The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional ~~Differences~~Variances

None.

~~B. Interpretations~~

~~None.~~

E. Associated Documents

- FAC-003-4 Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	January 20, 2006	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.	New
1	April 4, 2007	Regulatory Approval - Effective Date	New

~~Guideline and Technical Basis (attached).~~

2	November 3, 2011	Adopted by the NERC Board of Trustees	New
2	March 21, 2013	FERC Order issued approving FAC-003-2 (Order No. 777) FERC Order No. 777 was issued on March 21, 2013 directing NERC to "conduct or contract testing to obtain empirical data and submit a report to the Commission providing the results of the testing."[16]	Revisions
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."	Revisions
3	May 9, 2013	FAC-003-3 adopted by Board of Trustees	Revisions
3	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-003-3. This standard became enforceable on July 1, 2014 for Transmission Owners. For Generator Owners, R3 became enforceable on January 1, 2015 and all other requirements (R1, R2, R4, R5, R6, and R7) became enforceable on January 1, 2016.	Revisions

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

3	November 22, 2013	Updated the VRF for R2 from “Medium” to “High” per a Final Rule issued by FERC	Revisions
3	July 30, 2014	Transferred the effective dates section from FAC-003-2 (for Transmission Owners) into FAC-003-3, per the FAC-003-3 implementation plan	Revisions
4	February 11, 2016	Adopted by Board of Trustees. Adjusted MVCD values in Table 2 for alternating current systems, consistent with findings reported in report filed on August 12, 2015 in Docket No. RM12-4-002 consistent with FERC’s directive in Order No. 777, and based on empirical testing results for flashover distances between conductors and vegetation.	Revisions
4	March 9, 2016	Corrected subpart 7.10 to M7, corrected value of .07 to .7	Errata

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[17]

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)+	(AC) Maximum System Voltage (kV)[18]	MVCD (feet) Over sea level up to 500 ft	MVCD feet Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft	MVCD feet Over 11000 ft up to 12000 ft	MVCD feet Over 12000 ft up to 13000 ft	MVCD feet Over 13000 ft up to 14000 ft	MVCD feet Over 14000 ft up to 15000 ft
765	800	11.6ft	11.7ft	11.9ft	12.1ft	12.2ft	12.4ft	12.6ft	12.8ft	13.0ft	13.1ft	13.3ft	13.5ft	13.7ft	13.9ft	14.1ft	14.3ft
500	550	7.0ft	7.1ft	7.2ft	7.4ft	7.5ft	7.6ft	7.8ft	7.9ft	8.1ft	8.2ft	8.3ft	8.5ft	8.6ft	8.8ft	8.9ft	9.1ft
345	362[19]	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft
287	302	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft	5.8ft	5.9ft	6.1ft	6.2ft	6.3ft	6.4ft	6.5ft	6.6ft	6.8ft	6.9ft
230	242	4.0ft	4.1ft	4.2ft	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft
161*	169	2.7ft	2.7ft	2.8ft	2.9ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft	3.3ft	3.3ft	3.4ft	3.5ft	3.6ft	3.7ft	3.8ft
138*	145	2.3ft	2.3ft	2.4ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft	2.7ft	2.8ft	2.8ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft
115*	121	1.9ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.1ft	2.2ft	2.2ft	2.3ft	2.3ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft
88*	100	1.5ft	1.5ft	1.6ft	1.6ft	1.7ft	1.7ft	1.8ft	1.8ft	1.8ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.2ft	2.2ft
69*	72	1.1ft	1.1ft	1.1ft	1.2ft	1.2ft	1.2ft	1.2ft	1.3ft	1.3ft	1.3ft	1.4ft	1.4ft	1.4ft	1.5ft	1.6ft	1.6ft

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

[17] 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.

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

[19] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the Supplemental Materials for additional information.

+ Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[20]

For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)+	(AC) Maximum System Voltage (kV)[21]	MVCD meters Over sea level up to 153 m	MVCD meters Over 153m up to 305m	MVCD meters Over 305m up to 610m	MVCD meters Over 610m up to 915m	MVCD meters Over 915m up to 1220m	MVCD meters Over 1220m up to 1524m	MVCD meters Over 1524m up to 1829m	MVCD meters Over 1829m up to 2134m	MVCD meters Over 2134m up to 2439m	MVCD meters Over 2439m up to 2744m	MVCD meters Over 2744m up to 3048m	MVCD meters Over 3048m up to 3353m	MVCD meters Over 3353m up to 3657m	MVCD meters Over 3657m up to 3962m	MVCD meters Over 3962 m up to 4268 m	MVCD meters Over 4268m up to 4572m
765	800	3.6m	3.6m	3.6m	3.7m	3.7m	3.8m	3.8m	3.9m	4.0m	4.0m	4.1m	4.1m	4.2m	4.2m	4.3m	4.4m
500	550	2.1m	2.2m	2.2m	2.3m	2.3m	2.3m	2.4m	2.4m	2.5m	2..5m	2.5m	2.6m	2.6m	2.7m	2.7m	2.7m
345	362[22]	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m	1.7m	1.7m	1.8m
287	302	1.6m	1.6m	1.7m	1.7m	1.7m	1.7m	1.8m	1.8m	1.9m	1.9m	1.9m	2.0m	2.0m	2.0m	2.1m	2.1m
230	242	1.2m	1.3m	1.3m	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m
161*	169	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m	1.0m	1.0m	1.0m	1.1m	1.1m	1.1m	1.1m
138*	145	0.7m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m
115*	121	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.8m
88*	100	0.4m	0.4m	0.5m	0.5m	0.5m	0.5m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m
69*	72	0.3m	0.3m	0.3m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.5m	0.5m	0.5m

[20] 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.

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

[22] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the supplemental materials for additional information.

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

+ *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)*

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[23]

For **Direct Current** Voltages feet (meters)

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

[23] 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.

Guideline and Technical Basis

Effective dates:

The ~~first two sentences of the Effective Dates~~Compliance section is standard language used in most NERC standards to cover the general effective date and ~~is sufficient to cover~~covers the vast majority of situations. ~~Five~~A special ~~cases are needed to cover~~case covers effective dates for ~~individual~~(1) 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~~Standard, (2) lines ~~which are~~ changing ~~their~~in applicability within the standard~~, and those lines which are changing in a manner that removes their applicability to the standard.~~.

~~Case 1~~The special case 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 201~~1~~5 may identify a line to have that designation beginning in PY 202~~1~~5, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. ~~The table below has some explanatory examples of the application.~~

~~Date that Planning Study is completed~~	~~PY the line will become an IROL element~~	~~Date 1~~	~~Date 2~~	~~Effective Date The latter of Date 1 or Date 2~~
A~~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.

Date that Planning Study is completed	PY the line will become an IROL element	Date 1	Date 2	Effective Date The later of Date 1 or Date 2
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 3 is needed because a line operating at 200 kV or above that once was designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network. Such changes result in the need to apply R1 to that line until that date is reached and then to apply R2 to that line thereafter.~~

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

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

Defined Terms:

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

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

Explanation for revising the definition of Vegetation Inspection~~s~~:

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

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

Explanation of the de~~f~~ri~~ni~~va~~t~~ion of the MVCD:

The MVCD is a calculated minimum distance that is derived from the Gallet ~~E~~equation~~s~~. 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~~of the Standard provides MVCD values for various voltages and altitudes. ~~Details of the equations and an example calculation are provided~~The table is based on empirical testing data from EPRI as requested by FERC in ~~Appendix 1 of the Technical Reference Document.~~Order No. 777.

Project 2010-07.1 Adjusted MVCDs per EPRI Testing:
In Order No. 777, FERC directed NERC to undertake testing to gather empirical data validating the appropriate gap factor used in the Gallet equation to calculate MVCDs, specifically the gap factor for the flash-over distances between conductors and vegetation. See, Order No. 777, at P 60. NERC engaged industry through a collaborative research project and contracted EPRI to complete the scope of work. In January 2014, NERC formed an advisory group to assist with developing the scope of work for the project. This team provided subject matter expertise for developing the test plan, monitoring testing, and vetting the analysis and conclusions to be submitted in a final report. The advisory team was comprised of NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulation coordination, and vegetation management. The testing project commenced in April 2014 and continued through October 2014 with the final set of testing completed in May 2015. Based on these testing results conducted by EPRI, and consistent with the report filed in FERC Docket No. RM12-4-000, the gap factor used in the Gallet equation required adjustment from 1.3 to 1.0. This resulted in increased MVCD values for all alternating current system voltages identified. The adjusted MVCD values, reflecting the 1.0 gap factor, are included in Table 2 of version 4 of FAC-003.

The air gap testing completed by EPRI per FERC Order No. 777 established that trees with large spreading canopies growing directly below energized high voltage conductors create the greatest likelihood of an air gap flash over incident and was a key driver in changing the gap factor to a more conservative value of 1.0 in version 4 of this standard.

Requirements R1 and R2:
R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each applicable

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

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

Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations ~~as described more fully in the Technical Reference document~~.
These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

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

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation

related outages that could lead to Cascading." Thus violation severity increases with an applicable Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

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

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

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

Requirement R3:

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

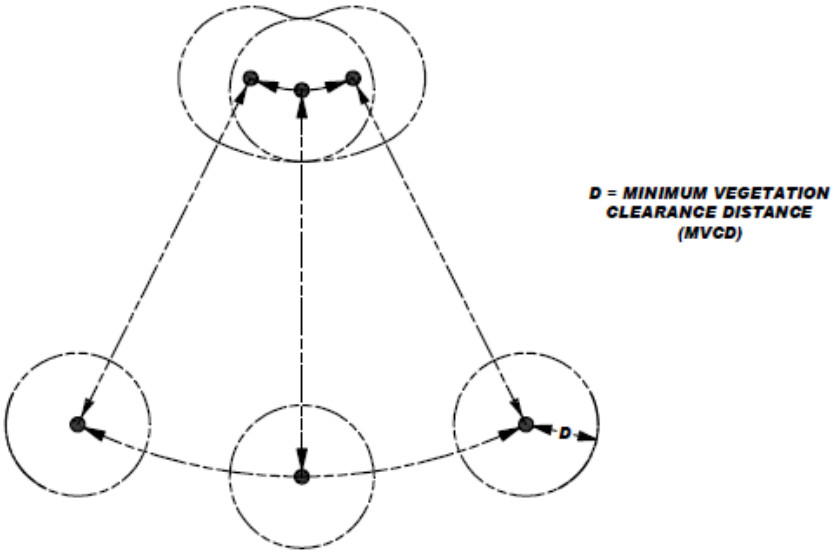
An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides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

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

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

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

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



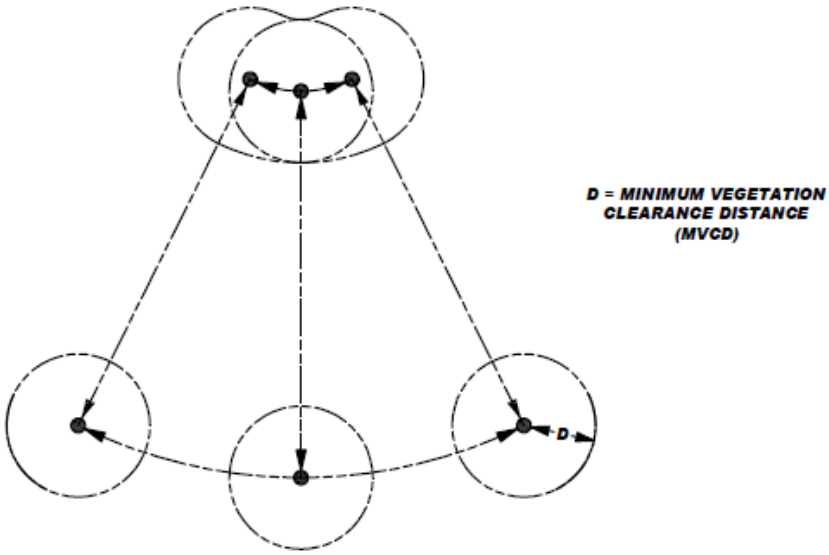


Figure 1

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

Requirement R4:
R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

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

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

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

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

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

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

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

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

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

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

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

Requirement R7:

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

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

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. ~~-~~For example recent line inspections may identify unanticipated

high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner's or applicable Generator Owner's system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.

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

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

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

~~FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)~~[24]

~~For **Alternating Current** Voltages (feet)~~

~~(AC) Nominal System Voltage (KV)~~	~~(AC) Maximum System Voltage (kV)~~[25]	~~MVCD (feet)~~ ~~Over sea level up to 500 ft~~	~~MVCD (feet)~~ ~~Over 500 ft up to 1000 ft~~	~~MVCD feet~~ ~~Over 1000 ft up to 2000 ft~~	~~MVCD feet~~ ~~Over 2000 ft up to 3000 ft~~	~~MVCD feet~~ ~~Over 3000 ft up to 4000 ft~~	~~MVCD feet~~ ~~Over 4000 ft up to 5000 ft~~	~~MVCD feet~~ ~~Over 5000 ft up to 6000 ft~~	~~MVCD feet~~ ~~Over 6000 ft up to 7000 ft~~	~~MVCD feet~~ ~~Over 7000 ft up to 8000 ft~~	~~MVCD feet~~ ~~Over 8000 ft up to 9000 ft~~	~~MVCD feet~~ ~~Over 9000 ft up to 10000 ft~~	~~MVCD feet~~ ~~Over 10000 ft up to 11000 ft~~
~~765~~	~~800~~	~~8.2ft~~	~~8.33ft~~	~~8.61ft~~	~~8.89ft~~	~~9.17ft~~	~~9.45ft~~	~~9.73ft~~	~~10.01ft~~	~~10.29ft~~	~~10.57ft~~	~~10.85ft~~	~~11.13ft~~
~~500~~	~~550~~	~~5.15ft~~	~~5.25ft~~	~~5.45ft~~	~~5.66ft~~	~~5.86ft~~	~~6.07ft~~	~~6.28ft~~	~~6.49ft~~	~~6.7ft~~	~~6.92ft~~	~~7.13ft~~	~~7.35ft~~
~~345~~	~~362~~	~~3.19ft~~	~~3.26ft~~	~~3.39ft~~	~~3.53ft~~	~~3.67ft~~	~~3.82ft~~	~~3.97ft~~	~~4.12ft~~	~~4.27ft~~	~~4.43ft~~	~~4.58ft~~	~~4.74ft~~
~~287~~	~~302~~	~~3.88ft~~	~~3.96ft~~	~~4.12ft~~	~~4.29ft~~	~~4.45ft~~	~~4.62ft~~	~~4.79ft~~	~~4.97ft~~	~~5.14ft~~	~~5.32ft~~	~~5.50ft~~	~~5.68ft~~
~~230~~	~~242~~	~~3.03ft~~	~~3.09ft~~	~~3.22ft~~	~~3.36ft~~	~~3.49ft~~	~~3.63ft~~	~~3.78ft~~	~~3.92ft~~	~~4.07ft~~	~~4.22ft~~	~~4.37ft~~	~~4.53ft~~
~~161*~~	~~169~~	~~2.05ft~~	~~2.09ft~~	~~2.19ft~~	~~2.28ft~~	~~2.38ft~~	~~2.48ft~~	~~2.58ft~~	~~2.69ft~~	~~2.8ft~~	~~2.91ft~~	~~3.03ft~~	~~3.14ft~~
~~138*~~	~~145~~	~~1.74ft~~	~~1.78ft~~	~~1.86ft~~	~~1.94ft~~	~~2.03ft~~	~~2.12ft~~	~~2.21ft~~	~~2.3ft~~	~~2.4ft~~	~~2.49ft~~	~~2.59ft~~	~~2.7ft~~
~~115*~~	~~121~~	~~1.44ft~~	~~1.47ft~~	~~1.54ft~~	~~1.61ft~~	~~1.68ft~~	~~1.75ft~~	~~1.83ft~~	~~1.91ft~~	~~1.99ft~~	~~2.07ft~~	~~2.16ft~~	~~2.25ft~~

~~[24] 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.~~

~~[25] Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.~~

~~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)~~

~~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~~	~~MVCD meters~~	~~MVCD meters~~	~~MVCD meters~~	~~MVCD meters~~	~~MVCD meters~~	~~MVCD meters~~	~~MVCD meters~~	~~MVCD meters~~	~~MVCD meters~~	~~MVCD meters~~	~~MVCD meters~~	~~MVCD meters~~

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

Notes:

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet ~~E~~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 use~~s~~d 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~~1 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~~was approximately 2.0 per unit. This value ~~is~~was 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~~was 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~~was considered a realistic maximum.

The Gallet ~~E~~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 ~~E~~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~~ Since no 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~~ existed at the time version 3 was developed, 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)~~

1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. ~~2)~~
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)~~
~~1)~~3) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

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

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

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

1. ~~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. ~~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. ~~3.~~ This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.

4. ~~4.~~ This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

Rationale for R3:
The documentation provides a basis for evaluating the competency of the applicable Transmission Owner's or applicable Generator Owner's vegetation program. There may be many acceptable approaches to maintain clearances. -Any approach must demonstrate that the applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions. ~~See Figure~~

Rationale for R4:
This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

Rationale for R5:
Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

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

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

Rationale for R6:
Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

Rationale for R7:
This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

~~Version History~~

~~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."~~	
~~3~~	~~May 9, 2012~~	~~FAC-003-3 adopted by Board of Trustees~~	
~~3~~	~~September 19, 2013~~	~~A FERC order was issued on September 19, 2013, approving FAC-003-3. This standard becomes enforceable on July 1, 2014 for Transmission Owners. For Generator Owners, R3 becomes enforceable on January 1, 2015 and all other requirements (R1, R2, R4, R5,~~	

		~~R6, and R7) will become enforceable on January 1, 2016.~~	
~~3~~	~~November 22, 2013~~	~~Updated the VRF for R2 from "Medium" to "High" per a Final Rule issued by FERC~~	
~~3~~	~~July 30, 2014~~	~~Transferred the effective dates section from FAC-003-2 (for Transmission Owners) into FAC-003-3, per the FAC-003-3 implementation plan~~	

Exhibit B

Implementation Plan

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan for FAC-003-4 — Transmission Vegetation Management

Requested Approval
FAC-003-4 – Transmission Vegetation Management

Requested Retirement
FAC-003-3 – Transmission Vegetation Management

Prerequisite Approvals
None.

Defined Terms in the NERC Glossary
None.

Effective Date
Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 3 months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 3 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Compliance Note

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 later 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.

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.

Standard for Retirement

FAC-003-3 11:59:59 p.m. on the day immediately prior to the Effective Date of FAC-003-4 in the particular jurisdiction in which the FAC-003-4 standard is becoming effective.

Exhibit D

Drafting Team Summary of EPRI Conductor-Tree Air Gap Flashover Testing

Drafting Team Summary of EPRI Conductor-Tree Air Gap Flashover Testing

Introduction

Testing completed by the Electric Power Research Institute (EPRI) of the strength of the air gap between transmission conductors and trees established an empirical basis for selection of an appropriate Gap Factor used in determining the revised Alternating Current (AC) Minimum Vegetation Clearance Distances (MVCD) values found in FAC-003-4. The testing also provided new insight as to how the shape of trees growing in proximity to energized conductors influences the likelihood of a flashover. The testing demonstrated that trees with large flat tops growing directly below energized high voltage conductors resulted in the weakest air gap. The intent of this document is to provide practitioners with additional context regarding the implications of the testing as it applies to vegetation management activities on the North American high voltage transmission grid.

Background

Following the 14 August 2003 Northeast Blackout, the Federal Energy Regulatory Commission (FERC), and subsequently the North American Electric Reliability Corporation (NERC), have been focused on reducing vegetation-related incidents by enforcing a Transmission Vegetation Management Standard. That standard, FAC-003-1, was adopted in 2006 and enforced in 2007 as a NERC Facilities Design, Connections, and Maintenance Reliability Standard for the electric utility industry.

A review of the record [1]of reportable Category 1 grow-in[2] outages since 2005 demonstrates that the industry has been successful in reducing the instances of flashovers due to vegetation, as seen in Figure 1.

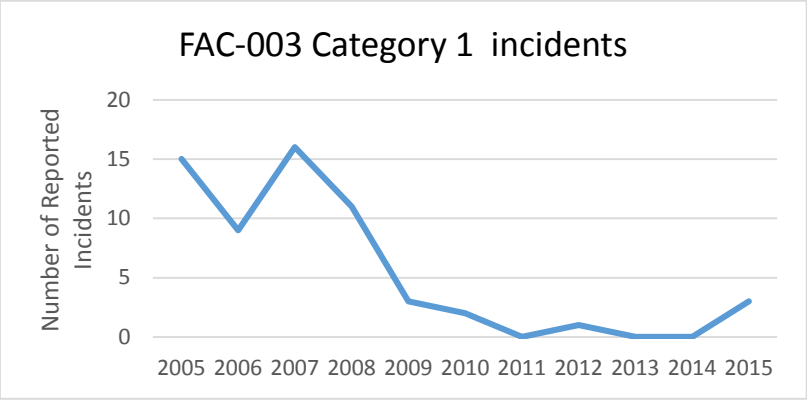


Figure 1 Reportable Category 1 outages since 2005

Integrated Vegetation Management

There are 160,000 miles of transmission line operating at 230 - 765 kV in the US. EPRI has estimated that the total land area being managed as transmission corridors encompasses 8.6

[1] See: http://www.nerc.com/pa/comp/ce/pages/vegetation-management-reports.aspx

[2] Category 1 is an outage caused by vegetation growing into lines from vegetation inside and/or outside of the right-of-way.

million acres. This land area is typically managed using the principles of Integrated Vegetation Management (IVM), which are intended to create, promote, and conserve stable plant communities that are compatible with overhead transmission lines, and to discourage incompatible plants that may pose a risk to the reliable operation of the transmission system. American National Industry Standards[3] (ANSI) and industry Best Management Practices[4] (BMPs) define IVM on transmission rights-of-way. IVM[5] uses combinations of methods to promote sustainable plant communities that are compatible with the intended use of the site, and to control, discourage, or prevent the establishment of incompatible plants that may pose safety, security, access, fire hazard, utility service reliability, emergency restoration, visibility, line-of-sight requirements, regulatory compliance, environmental, or other specific concerns. Both references define a *"wire zone"* below the electric supply lines, which is typically managed to promote low-growing, primarily herbaceous, vegetation. Incompatible tree species growing in the wire zone present the greatest likelihood of encroachment within MVCDs, leading to a reportable Category 1 event.

Air Gap Factors and MVCD

MVCDs in the initial version of FAC-003-1 were based on IEEE Standards that established minimum air insulation distances[6] (MAID) for live line work. The MAID and MVCD distances were determined for the case when a transient overvoltage (TOV) occurs due to switching operation. The MAID clearance distances, which pertain to line work, were believed to be very conservative when applied to tree-conductor clearances.

The calculation method for determining MVCDs in later versions of FAC-003 utilizes the Gallet equation multiplied by a gap factor (k_g) to describe the strength of the air gap MVCDs in the subsequent version FAC-003-2 and FAC-003-3 are based on this method, and also used a level of expected TOVs by voltage class. MVCDs in both versions 2 and 3 are based on a Gap Factor (k_g) of 1.3.

As a result, new MVCDs were approved[7] with an additional caveat directing NERC "*to conduct or contract testing to develop empirical data regarding the flashover distances between conductors and vegetation," and to use an approach based on "statistical analysis [that] would then evaluate the test results and provide empirical evidence to support an appropriate gap factor to be applied in calculating minimum clearance distances using the Gallet equation."* [8]

Twelve of 20 high voltage tests performed by EPRI yielded gap factors lower than 1.3, which was used in the calculations to determine the MVCDs in FAC-003-3. These test results indicated that a Gap Factor of 1.3 may not be suitable for all situations. As a result, the NERC Advisory Team recommend use of a Gap Factor of 1.0 as a more conservative approach. FAC-003-4 reflects the revised MVCD values using the

[3] ANSI A300 (Part 7) -2012 *"Tree, Shrub, and Other Woody Plant Management – Standard Practices (Integrated Vegetation Management, a. Utility Rights-of-way."*
[4] BMP *"Integrated Vegetation Management" 2nd Edition* (20142), International Society of Arboriculture.
[5] Ibid, IVM BMP 2014, page 5.
[6] IEEE Std. 516-2003, *"IEEE Guide for Maintenance Methods on Energized Power Lines".*
[7] FERC Order 777
[8] FERC Final Rule *"Revisions to Reliability Standards for Transmission Management*", 21 March 2013

Gallet equation and a Gap Factor of 1.0. MVCDs in FAC-003-4 were increased compared to FAC-003-3 based on the lower Gap Factor, yet still are less than those found in FAC-003-1.

Air Gap Flashover Testing

The testing focused on AC MVCDs which by definition apply to distances between trees and conductors, and are relevant to two categories of reportable outages as defined in FAC-003-3.

> Category 1 – Grow-ins: Sustained Outages caused by vegetation growing into applicable lines by vegetation inside and/or outside of the ROW. *This relates to a vertical gap.*
>
> Category 4 – Blowing together: Sustained Outages caused by vegetation and applicable lines blowing together from within the ROW. *This relates to a horizontal gap.*

Outages due to trees failing structurally and striking transmission conductors (Categories 2, 3) were not included in the investigation.

The history of reportable incidents since 2005 was reviewed to determine the species and crown characteristics of the trees that had been involved in reported outages. This information was used to determine the tree types tested.

Switching surge impulse tests were performed for each system voltage level to determine the average strength (critical flashover voltage) of the conductor to tree gaps. The results were then used to determine whether the Gap Factor used with the Gallet equation to calculate the MVCDs was appropriate. These tests revealed that a Gap Factor of 1.0 was more appropriate to use than a Gap Factor of 1.3.

Revised MVCD values in FAC-003-4 were calculated based on a Gap Factor of 1.0 and tests performed again at the TOV levels specified in the standard to show that the conductor tree gaps *were* able to withstand the voltages. The 230 kV test results are shown in the table below. The switching impulse flashover and withstand voltages[9] are significantly greater than the nominal line AC voltages because MVCDs are determined by applying switching over voltages and not every day 60Hz operating voltages.

Table 1 Example of operating voltages and voltages applied during Gap Factor tests.

Nominal Ø-Ø AC Voltage	Ø-ground(tree) AC Voltage	Critical Flashover Switching Impulse Test Voltage	Withstand Switching Impulse Test Voltage
230kV	133kV	496-590kV	395kV

One of the key findings from the test was the impact of the tree size and shape on the flashover strength of the air gap between the tree and conductor. This impact can be explained theoretically:

- Theoretically, the weakest conductor gap is a "conductor-plane gap" shown in figure 2 with a Gap Factor of k_g=1.1. This is similar to a "conductor vase shaped tree gap" which was measured with a Gap Factor of k_g*=1.03 – 1.15.*

[9] "Withstand voltage" is defined as the voltage at which flashover will only occur 0.13% of the time.

- The strongest conductor gap is considered to be a "conductor-rod gap" with a Gap Factor of k_g=1.4-1.6. This is similar to a "conductor pyramidal shaped tree gap" which was measured with a Gap Factor of k_g=*1.44.*

As a result, the testing provides the new insight that trees with large flat tops growing directly below energized high voltage conductors resulted in the weakest air gap as compared to pyramidal shaped trees.

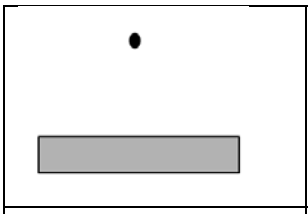
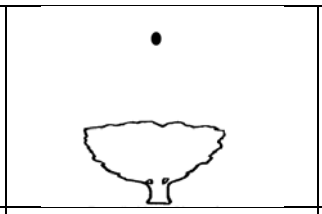
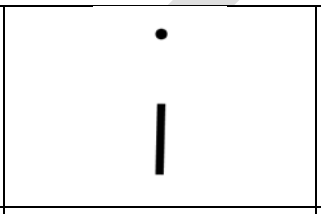
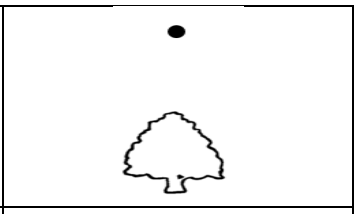
			
Conductor - Plane	*Conductor Vase Tree*	*Conductor - Rod*	*Conductor - Pyramidal*
k_g=1.1	*k_g=1.03 – 1.15*	*k_g=1.4-1.6*	*k_g=1.44*

Figure 2 Examples of Gap Factors (kg) between a conductor and rods, planes and trees

Situations That Increase the Likelihood of a Conductor-Tree Flashover

Season

The majority of the reported Category 1 outages since 2005 have occurred during the growing season. Factors that contribute to this are:

- Tree growth varies within a growing season. Stem elongation begins shortly after full leaf development[10], and is typically completed by August. As a result, clearance is lost during the first half of the growing season.
- Ambient air temperatures and system loads are high in the summer, resulting in greater conductor sag and loss of clearance.
- The crown of a deciduous tree more closely simulates a conductive plane during the growing season due to the presence of more leaves and increased mositure in the branches.

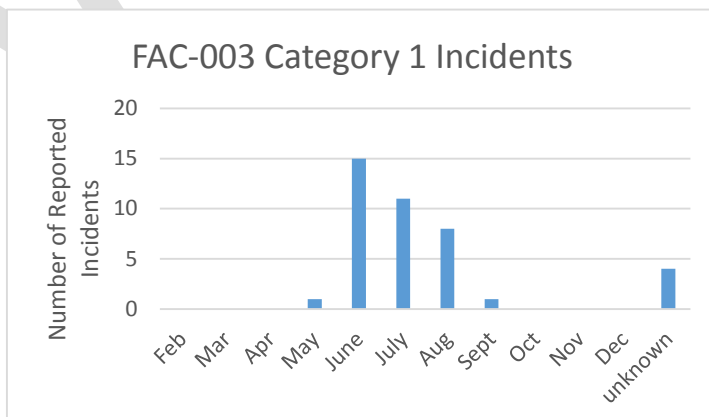


Figure 3 Seasonal trend in reportable Category 1 outages.

[10] This is generally true for most of North America. In arid regions tree growth may be initiated with rainfall, and in subtropical regions stem elongation may occur over longer periods.

Voltage

The 230kV MVCDs (based on a Gap Factor of 1.3) found in FAC-003-3, when tested from conductor to a broad, flat-topped tree, failed the voltage withstand test and are a primary reason that the MVCDs in FAC-003-4 are being revised to utilize a more conservative Gap Factor of 1.0. Therefore, through the testing, the revised MVCDs were evaluated for various tree shapes, below or adjacent to lines of any voltage class.

Line Clearance Pruning

While some species of trees may naturally develop broad flat-topped crowns, this condition is more likely to be created by trees maintained by crown reduction pruning[11] using directional pruning[12] techniques which involves selective removal of limbs to reduce the overall height of a tree. The result of pruning can lead to the development of a broadly spreading, flat-topped crown directly under transmission conductors. As identified in the EPRI testing, this is the type of tree-conductor configuration that results in the weakest air gap. Directional side pruning of trees along the edge of narrow corridors also has the potential to create a horizontal plane with a similarly weakened air gap.

There are typically three reasons why trees are pruned rather than removed in the wire zone directly under transmission conductors:

1. Preservation of riparian vegetation associated with streams and wetlands in the right-of way.
2. Maintaining a visual screen or barrier between areas frequented by the public and the right-of-way.
3. Retention of landscape trees in parks and on private property.

Each of these scenarios may increase the likelihood of encroachment to within MVCDs, and must be addressed to ensure reliability of the transmission system.

Confidence in the new MVCDs

The "*Transmission Vegetation Management NERC Standard FAC-003-2 Technical Reference*" states that the probability of an air gap flashover between a conductor and a tree at MVCDs is 10^{-6}; however, we have been unsuccessful in confirming the assumptions associated with the statement. Based on our best understanding of the approach developed by the original authors, we have used accepted methodology[13] to provide an estimate. The resulting calculated risk of a flashover is 2.49×10^{-4}, based on a probability of flashover of 0.135% at MVCD and a transient overvoltage that has a 2% probability of exceeding the defined levels. This equates to less than one flashover across MVCDs per 4000 switching surges.

[11] ANSI A300 (Part 1) -2008 *"Tree, Shrub, and Other Woody Plant Management – Standard Practices (Pruning)*

[12] BMP *"Utility Pruning of Trees"*, (2004) International Society of Arboriculture

[13] "Transmission Vegetation Management NERC Standard FAC-003-2 Technical Reference" FAC-003, and IEEE Std. 516-2009, "IEEE Guide for Maintenance Methods on Energized Power Lines".

Additionally, the worst case tree shape (large flat-topped vase shape) was shown to have Gap Factor (k_g) of 1.03. Since this is higher than the Gap Factor used in the calculation, the resulting tree-conductor clearances are somewhat greater based on a Gap Factor of 1.0 and provides additional confidence.

Placing the Likelihood of Air Gap Flashovers in Perspective

The revisions to the AC MVCDs in FAC-003-4 provide a substantial degree of certainty that with compliance, the likelihood of a flashover between an energized conductor and a tree is extremely low:

- The MVCDs are based on potential transient overvoltage (switching surge) conditions associated with switching operations in the system. The vast majority of the time the system operates at steady state nominal voltages.
- The industry recognizes that MVCDs are not the targeted clearances for a vegetation management program, and has a goal to maintain tree-conductor clearances well in excess of MVCD.
- The weakest air gap tree-conductor configuration identified in the study, was that of a broadly spreading flat-topped tree directly below a conductor, yielded a Gap Factor between 1.03 and 1.15. Since these Gap Factors are higher than that (k_g 1.0) utilized for the MVCD calculations, the actual likelihood of a flashover reduced, since the actual MVCDs require greater clearance.
- The testing provided new insight regarding the influence of tree shape on the likelihood of an air gap flashover. This new information will provide practitioners with an informed basis to enhance vegetation maintenance strategies and/or methods that address scenarios where trees are being maintained on transmission rights-of-way.

Summary

EPRI's testing on the strength of the air gap between energized high voltage conductors and trees established a quantitative basis for the MVCD values in FAC-003-4. Maintaining the new AC MVCDs reduces the likelihood of an air gap flashover to a tree on the transmission system.

The tests also demonstrated that trees with broad flat tops growing directly below high voltage conductors create the weakest air gap for a potential flashover incident. This condition is most often associated with trees that are being maintained by repeated crown reduction pruning[14]. As a result, line clearance pruning of trees directly under transmission conductors may unintentionally increase potential exposure to a flashover between a transmission line and the tree, and emphasizes the need to maintain MVCD within FAC-003-4. A similar condition may develop in the case of trees adjacent to conductors.

[14] ANSI A300 (Part 1) -2008 *"Tree, Shrub, and Other Woody Plant Management – Standard Practices (Pruning), section 9.3.*

Exhibit E

EPRI Reports

Exhibit E-1 April 2015 Testing to Confirm or Refine Gap Factor Utilized in Calculation of Minimum Vegetation Clearance Distances (MVCD)

ELECTRIC POWER RESEARCH INSTITUTE

Testing to Confirm or Refine Gap Factor Utilized in Calculation of Minimum Vegetation Clearance Distances (MVCD)

Test Results and Analysis

2015 TECHNICAL REPORT

Testing to Confirm or Refine Gap Factor Utilized in Calculation of Minimum Vegetation Clearance Distances (MVCD)

Test Results and Analysis

3002006078

Technical Report, April 2015

EPRI Project Manager

R. Lordan

ELECTRIC POWER RESEARCH INSTITUTE
3420 Hillview Avenue, Palo Alto, California 94304-1338 ▪ PO Box 10412, Palo Alto, California 94303-0813 ▪ USA
800.313.3774 ▪ 650.855.2121 ▪ askepri@epri.com ▪ www.epri.com

THE FOLLOWING ORGANIZATIONS PREPARED THIS REPORT:

Electric Power Research Institute (EPRI)

Engelbrecht Consulting B.V.

BioCompliance Consulting, Inc

John Kuffel Consulting

NOTE

For further information about EPRI, call the EPRI Customer Assistance Center at 800.313.3774 or e-mail askepri@epri.com.

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The following organizations prepared this report:

Electric Power Research Institute (EPRI)

Principal Investigators
D. Childs
R.J. Lordan
A. Phillips

Engelbrecht Consulting B.V.
Catharinadaal 84
Ede, 6715 KD
The Netherlands

Principal Investigator
C. S. Engelbrecht

BioCompliance Consulting, Inc.
7710 196th Ave NE
Redmond, WA 98053

Principal Investigator
J. Goodfellow

John Kuffel Consulting
3143 25th Side Rd
Rockwood, Ont. N0B 2K0

Principal Investigator
J. Kuffel

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PRODUCT DESCRIPTION

Switching Impulse testing was performed on a range of vegetation shapes for a range of transmission nominal voltages from 230 kV to 765 kV, and configurations. Repeatable tests were performed with cut trees which were fitted with a grounded metal rod and a metal rod with one section replaced with a wooden dowel. Withstand tests were performed with natural trees to validate the conservatism of the partially conduction tree shapes. The results were analyzed to provide estimates of the insulation flashover strength from conductor bundles to natural vegetation.

This report provides a detailed description of the switching impulse tests that were performed on representative tree shapes. This includes a description of the test setups, the procedure used and test results. The report also contains a discussion and analysis of the results to provide utilities, the North American Electric Reliability Corporation (NERC), and the Federal Energy Regulatory Commission (FERC) with information which can be used to determine the minimum vegetation clearance distance (MVCD) from energized conductors to natural vegetation.

Background

A potential cause of blackouts may be vegetation-related outages. The industry has made progress in reducing the instances of vegetation-related flashovers. Nevertheless, FERC, and subsequently NERC, are focused on further reduction of vegetation related risks.

In response to FERC Order No. 693, NERC submitted the reliability standard FAC-003-2 (Transmission Vegetation Management. In the submittal, NERC proposed a methodology for calculating the minimum vegetation clearance distances (MVCD) based on the Gallet Equation and the use of a gap factor pursuant to FAC-003-2.

On March 21, 2013, FERC issued its Final Rule of the "Revisions to Reliability Standard for Transmission Vegetation Management," in which NERC Reliability Standard FAC-003-2 was approved and NERC was directed "to conduct or contract testing to develop empirical data regarding the flashover distances between conductors and vegetation," and to use an approach based on "statistical analysis [that] would then evaluate the test results and provide empirical evidence to support an appropriate gap factor to be applied in calculating minimum clearance distances using the Gallet equation."

Objectives

The purpose of this project is to provide empirical evidence to support the selection of an appropriate gap factor that will be applied in calculating the MVCD using the Gallet Equation. The experimental results will also be used to verify if the MVDC values proposed in NERC Reliability Standard FAC-003-2 are appropriate.

Approach

Switching impulse tests were designed and executed at EPRI's Lenox High Voltage Laboratory in Lenox, Massachusetts to validate the gap factor utilized in NERC FAC-003-2. Multiple tree shapes were selected for trees which were both vertically and horizontally offset from energized conductor bundles for four voltage levels between 230 and 765kV.

The first test series was conducted on simulated trees which comprised of freshly cut trees with a grounded metal rod. From the perspective of switching impulse flashover, this configuration

gives a close, but conservative electrical representation of natural vegetation, and at the same time facilitates a repeatable experiment, which is a requirement in the FERC Ruling.

A second series of switching impulse flashover tests were performed on simulated trees which comprised of freshly cut trees with a replaceable wooden dowel section and a metal central rod. The wooden dowel was replaced after each flashover. This is a time-consuming test that has the benefit of providing a statistically reproducible test that is a close approximation to that of natural vegetation.

Lastly switching impulse withstand tests were performed on natural vegetation to demonstrate that for the tree species and tree shapes available in the Lenox test site, the MVCD calculation method is a conservative model and methodology.

Results

Test results showed that the two gap configurations (i.e. tree shape / conductor) resulting in the lowest flashover voltages, and therefore to the most conservative MVCD values, are; a horizontal offset to a columnar (wide) configuration, and a vertical offset above a vase tree (flat-top). In both cases, the results indicate a gap factor of approximately 1.1which is lower than the gap factor of 1.3 proposed in the NERC FAC-003-2 standard. A lower gap factor will result in a larger MVCD.

Further, in the case of the vertical offset above a flat top tree, it was found that the strength of the gap weakens with increasing radius of the tree top, such that the most conservative configuration is a flat top tree in which the radius is larger than the gap length.

Applications, Value, and Use

This research is performed to provide an empirical basis to verify the values of minimum vegetation clearance distances (MVCD) in the NERC Reliability Standard FAC-003-2. From the results it was concluded that the values in the table, based on a gap factor of 1.3, are not conservative. It is expected that the NERC standard writing process will utilize these results in the reviewing the present standard.

Keywords

Minimum vegetation clearance distances (MVCD)
Impulse Testing
Clearance Distance

ABSTRACT

NERC proposed a methodology for calculating the minimum vegetation clearance distances (MVCD) based on the Gallet Equation and the use of a gap factor. EPRI's approach was to derive the gap factor for vegetation using empirical evidence, and compare those results to the gap factor utilized by NERC. The project pursued a statistically valid scientific approach.

Flashover tests were performed on representative conductor-to-vegetation gap configurations at four system voltage levels based on various vegetation geometries and transmission line configurations. The test configurations utilized simulated trees constructed with natural vegetation, freshly harvested wooden dowels and conductive objects. Finally, voltage withstand tests were performed on select natural vegetation to statistically demonstrate that the gap factor determined for the artificial vegetation represents a conservative estimate of the gap factor for fully conductive tree subjects.

The results were analyzed and compared against the value listed in the NERC FAC-003 Standard.

EXECUTIVE SUMMARY

A potential cause of blackouts may be vegetation-related outages. NERC has submitted the Reliability Standard FAC-003-2 (Transmission Vegetation Management) to FERC. In the submittal, NERC proposes a methodology for calculating the minimum vegetation clearance distances (MVCD) based on the Gallet Equation and the use of a gap factor. FERC proposes to approve the standard, but seeks empirical evidence of the efficacy of the approach.

The gap factor (k_g) is dependent on geometry and is determined from a statistically valid number of switching impulse tests on representative configurations. Multiple tree shapes were selected and tested for both a vertical offset and a horizontal offset from energized transmission conductor.

Test Series 1: Switching impulse flashover tests were performed for all combinations of tree shapes and voltages, both for vertical (Test 1.1) and horizontal (Test 1.2) offset directions. The tree shapes were comprised of freshly cut trees with a grounded metal rod. From the perspective of switching impulse flashover, this configuration gives a close, but conservative electrical representation, and facilitates a repeatable experiment, which is a requirement for determining the impulse strength as directed in the FERC Ruling.

Test Series 2: Switching impulse flashover tests were performed using recently harvested canopies of test trees with a replaceable wooden rod. The electric field distribution of the configuration employing the wooden section provided a close approximation of the natural vegetation. While this is a time-consuming test, it has the benefit of providing a statistically reproducible test that is a close approximation to that of natural vegetation.

Test Series 3: Lastly, switching impulse withstand tests were performed on natural trees. The objective of these tests was to demonstrate that, for the tree species and tree shapes available in the Lenox test site, the MVCD calculation method is a conservative model and methodology.

Due to unexpected test results, further impulse flashover testing was performed on recently harvested trees without any conductive central rods. The results helped explain the strength characteristics observed during the withstand testing on natural trees.

Results

This report highlights important differences between the flashover performance for various tree configurations, offset directions, and electrical makeup.

The first set of tests employed a fully grounded metal rod with the tree being tested as described in Chapter 3. Five tree configurations (three with vertical clearance, and two with horizontal clearance) were tested at four nominal voltage classes from 230 kV to 765 kV. Each voltage class employed a different number of sub conductors in the bundles and with conductor to tree spacings based on the FAC-003 standard. The tree shape and voltage class which yielded the lowest gap factor was the Columnar, 230 kV, Horizontal offset. It yielded a gap factor of 1.02. That configuration was then used in the wooden dowel test. The two lowest gap factors were then used in the withstand test (Columnar, 230 kV, Horizontal offset and Vase: 230kV Vase Vertical Offset)

The wooden dowel test (Test 2) yielded a gap factor of 1.22, demonstrating that the switching impulse strength of a gap comprising the energized conductor and a "wooden branch end electrode" (gap factor = 1.22) is greater than that of an identical gap comprising the energized conductor and a "metal end electrode (gap factor = 1.02).

Voltage withstand testing was performed using a critical switching impulse waveform on natural vegetation under the Lenox test line. Two trees, representative of the range of species and tree shapes, were selected for testing.

The columnar-shaped, 230 kV, horizontal configuration passed the withstand impulse test. The vase-shaped, 230 kV, vertical configuration failed the withstand impulse test. Detailed results, analysis, and conclusions are provided in the associated sections of the report.

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1
INTRODUCTION

Background

Vegetation related outages have been identified as a significant cause of outages in the overhead line electrical network. In recent years there has been an increased focus to reduce vegetation related outages, also in response to the Northeast blackout which was precipitated by a vegetation caused outage. The industry has made progress in reducing the instances of flashovers due to vegetation, and the Federal Energy Regulatory Commission (FERC or Commission), and subsequently the North American Electric Reliability Corporation (NERC), are focused on further reducing vegetation related risks.

In response to FERC Order No. 693, NERC submitted the reliability standard FAC-003-2 (Transmission Vegetation Management) as the Commission-certified Electric Reliability Organization. In the submittal, NERC proposed a methodology for calculating the minimum vegetation clearance distances (MVCD) based on the Gallet Equation[1] and the use of a gap factor pursuant to FAC-003-2.

The gap factor (k_g) is used to describe the critical switching surge flashover voltage (CFO_{SOV})[2] of a specific configuration compared to a rod-plane geometry (CFO_{SOV}(Rod-Plane)):

$$CFO_{SOV} = k_g \ X \ CFO_{SOV}(Rod\text{-}Plane)$$

The CFO_{SOV} *(Rod-Plane)* is calculated using the Gallet Equation.

The gap factor is used to estimate the CFO of a configuration using the configurations geometry and the CFO of a rod plane. It has the advantage that it scales across the range of gap sizes, but is inherently an approximation. The accuracy of the gap factor for unknown configurations, e.g. tree to conductor, is not known. The gap factor (k_g) is dependent on geometry and is determined from a statistically valid number of switching impulse tests on representative configurations. Some typical values of k_g are shown in Table 1-1. Additional configurations and values can be found in Hileman's book: "*Insulation Coordination for Power Systems*".

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[1] The Gallet Equation is an accepted basis for calculating the air gap required between a conductor and a transmission line tower (i.e., the grounded object) to avoid flashover. NERC has applied the Gallet Equation to calculate the minimum air gap that could exist between a conductor and vegetation (conductor-to-vegetation gap) to avoid a flashover. This calculated minimum conductor-to-vegetation gap is then used to set the MVCD. The Gallet Equation is particularly useful as it can be applied to a variety of conductor-to-vegetation gap configurations by the application of appropriate gap factors. The conductor-to-vegetation gap configuration may consist of the conductor being located vertically above and horizontally to the side of the vegetation in concern, or any combination thereof. See NERC Reliability Standard FAC-003-2 at 29-30, available at http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=FAC-003-2&title=Transmission%20Vegetation%20Management&jurisdiction=United%20States.

[2] The CFO Voltage is the peak switching surge voltage at which a 50% probability of flashover occurs.

Table 1-1
Example Gap Factors (k_g)

Gap Configuration	Range of k_g	Typical value of k_g
Rod-plane	1.00	1.00
Rod-rod (vertical)	1.25 – 1.35	1.30
Rod-rod (horizontal)	1.25 – 1.45	1.35
Conductor-lateral structure	1.25 – 1.40	1.30
Conductor-lower rod	1.40 – 1.60	1.50
Conductor-plane	1.1	1.1

The NERC Standard Drafting Team (SDT) relied on the book "*Insulation Coordination for Power Systems*", by Andrew Hileman, to develop a table of proposed minimum vegetation clearance distances (MVCD) using a gap factor equal to 1.3.

On March 21, 2013, FERC issued its Final Rule of the "Revisions to Reliability Standard for Transmission Vegetation Management[3]," in which NERC Reliability Standard FAC-003-2 was approved and NERC was directed "to conduct or contract testing to develop empirical data regarding the flashover distances between conductors and vegetation," and to use an approach based on "statistical analysis [that] would then evaluate the test results and provide empirical evidence to support an appropriate gap factor to be applied in calculating minimum clearance distances using the Gallet equation."

In response to the FERC order, elements that comprise the minimum vegetation clearance distance (MVCD) were explored in support of test plan development. In addition to the Gallet equation and the associated *gap factor*, which refers to the insulation strength at sea level, there are numerous elements that contribute to the determination of the MVCD. These include adjustment factors for altitude, evaluation of system transients and transmission line design factors. None of these are in question. Additionally, the efficacy of the Gallet equation itself has not been questioned by the FERC.

Objective

The objective of this project is to confirm, or if necessary advise NERC of, the adequacy of the gap factor (k_g) of 1.3 proposed by NERC as a basis for the calculation of minimum vegetation clearance distances (MVCD) utilizing the method documented in NERC Reliability Standard FAC-003-2. Validation or refinement of the gap factor will verify that the MVCD values in NERC Reliability Standard FAC-003-2 will support reliable operation.

Approach

Validating the appropriateness of the *gap factor*, k_g, selected by the NERC Standard Drafting Team (SDT) to utilize for the conductor to vegetation gap configuration is challenging because a statistically valid and scientifically conservative approach is required. EPRI's approach was

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

designed to determine the gap factor for representative vegetation configurations based on empirical evidence as described below, and compare the determined gap factor to that proposed by NERC.

A simple, yet ineffective, approach would be to directly perform impulse testing on various tree shapes. However, utilizing natural vegetation in switching impulse tests has the following limitations:

1. A statistically valid number of flash-over impulses cannot be derived from a single tree, because each successive flash-over changes the electrical characteristics of the tree.
2. There is a wide range of variations of trees, tree combinations (single verses clusters), live and dead trees, wet and dry trees, soil conditions, etc. If testing is performed on any single type of tree, one must be confident that the scenario represents the worst case from a flashover perspective and that there is no other type of vegetation that would result in a lower gap withstand.

These limitations were overcome by devising a representative test setup that would produce repeatable results to facilitate statistically significant testing. The approach was:

1. Identify representative shapes of incompatible trees that may occur within transmission ROW's and then to use these shapes as a basis for designing a few representative conductor to tree gap configurations.
2. *Flashover Impulse tests to recently harvested (i.e. cut) trees with grounded metal rod:* This test includes the full range of representative tree shapes and gap configurations. The vegetation was represented in the test by a freshly cut tree of appropriate shape which was fitted with a fully grounded metal rod that served as the electrode to which flashover occurs. From the perspective of switching impulse flashover, this configuration gives a close, but conservative electrical representation of the situation existing on right of ways which run through natural vegetation, and at the same time facilitates a repeatable experiment, which is a requirement for determining the impulse strength as directed in the FERC Ruling.
3. *Flashover Impulse tests to recently harvested (i.e. cut) trees with wooden dowel on conductive center rod:* Limited tests were performed on the tree shape and gap configuration that had the lowest gap factor as determined by the first test series. For this test series the last section of the metal rod was replaced by a specially prepared wooden dowel, to more closely approach a natural tree configuration. The wooden dowels were replaced after each flashover to achieve consistent results.

   The wooden dowel test provides a statistically valid estimate of the impulse flashover strength for a specified voltage and tree shape. The test is designed to demonstrate that the metal rod tests is a conservative model (would yield a lower gap factor) than the equivalent test employing a wooden rod in lieu of a grounded metal rod.

4. *Withstand Impulse tests on natural vegetation:* The final test provides impulse voltage withstand testing on natural vegetation (the natural vegetation is tested in place where the tree has grown for the approximately five years). The objective of the withstand tests is to verify, for the tree species and tree shapes available in the Lenox test site, that the MVCD calculation method is a valid, conservative model and methodology.

A summary of this approach is provided in Table 1-2 with references to the chapters where it is discussed. All tests were executed at the EPRI-Lenox Test Facility in Lenox, MA – see Figure 1-1. The Lenox Facility was selected because it offers all necessary capabilities necessary for the required impulse testing. Additionally, the Lenox Facility includes a stand of new growth trees available for harvesting for Tests series 1 and 2, and for the withstand testing of natural trees as in Test series 3.

Table 1-2
Test Approach

Test series #	Test Description	Chapter	Number of test config-urations	Purpose	Limitations/ Considerations
Prep.	Develop Test Plan	2		Identify representative tree shapes and conductor to tree gap configurations	
1	Impulse to Fully Grounded Metal Rod	3	20	Provide a (presumably) conservative, statistically valid representation of the gap factors.	Further testing is required to establish that the approach utilizing the fully grounded metal rod is truly conservative.
2	Impulse to Wooden Dowel	4	1	Demonstrate that the switching impulse strength of a gap comprising the energized conductor and a wooden dowel is greater than that of an identical gap comprising the energized conductor and a fully grounded metal rod.	The test execution is of excessive duration to such an extent that it is impractical to apply this test approach to all 20 configurations.
3	Withstand Test to Natural Vegetation	5	2	Verify that the MVCD calculation method is applicable.	This test will not provide a statistical representation of Gap Factor, only a pass-fail result on a specific voltage level and vegetation type.

Figure 1-1
EPRI-Lenox Transmission Test Facility, Lenox, MA

2
DEFINITION OF TEST CONFIGURATIONS CONSIDERED

An important part the work to verify the gap factor selected by the NERC Standard Drafting Team (SDT) to develop a table of proposed minimum vegetation clearance distances (MVCD) is to define a representative gap configuration. This comprised to elements:

- The definition of representative tree shapes that should be considered
- Design of a representative bundle and gap configuration, and dimensions for each of the system voltages that should be considered.

In addition, it was also necessary to define a test circuit that could be used to perform switching impulse tests on the various gap configurations within the limitations imposed by the applicable standards for high-voltage testing.

Definition of representative tree types considered

Objective

The tree definition task was designed to identify the species (genus, family) of incompatible trees that may occur within transmission ROW's, creating elevated risk of flashover from high-voltage conductors. Tree species can be expected to vary regionally and by site type. While it is impractical to test all tree species and shapes, the test is designed to cover the range of shapes that can be expected in and around transmission rights-of way. There are 160,000 miles of transmission line operating at 230 kV through 765 kV in the US. EPRI has estimated that the total land area being managed as transmission corridors encompasses 8.6 million acres. The risk of an incompatible tree in the wire zone growing to within Minimum Vegetation Clearance Distance (MVCD) varies by site type, land use, and in some cases, restrictions as to vegetation maintenance practices.

The issue of concern for the purposes of this project is the establishment of the MVCD found in the NERC Reliability Standard FAC-003-3. The specific violation categories of interest to this project are:

- Category 1 – *Grow-ins*: Sustained Outages caused by vegetation growing into applicable lines by vegetation inside and/or outside of the ROW. *This relates to a vertical gap.*
- Category 4 – *Blowing together*: Sustained Outages caused by vegetation and applicable lines blowing together from within the ROW. *This relates to a horizontal gap.*

Categories 2 and 3 are not part of this project:

- Category 2 – *Fall-ins: Outages caused by vegetation falling into lines from inside the ROW.*
- Category 3 – *Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.*

Vertical Gap

Trees associated with grow-in violations will typically exhibit juvenile form and are approximately 25 feet to 35 feet (8 meters to 12 meters) tall. Three basic types have emerged as representative.

1. Conifers (spruce, fir, pine) typically have a well-defined central leader. Their shape is described as moderately **pyramidal**. Some deciduous trees may have an excurrent (organized) form, though typically somewhat less well defined as compared to conifers. Their shape can also be described as pyramidal.
2. Deciduous trees may also exhibit less central dominance, referred to as a decurrrent (random) form. Their shape is described as moderately **columnar**.
3. The third shape involves larger trees with crowns that have been maintained by pruning. This occurs when the utility has been unable to remove trees within the wire zone. The crown form in this case would be asymmetrical or perhaps even "flat topped". Their shape is described as broadly **vase-shaped**.

Schematic representations of these tree shapes are presented in Figure 2-1.

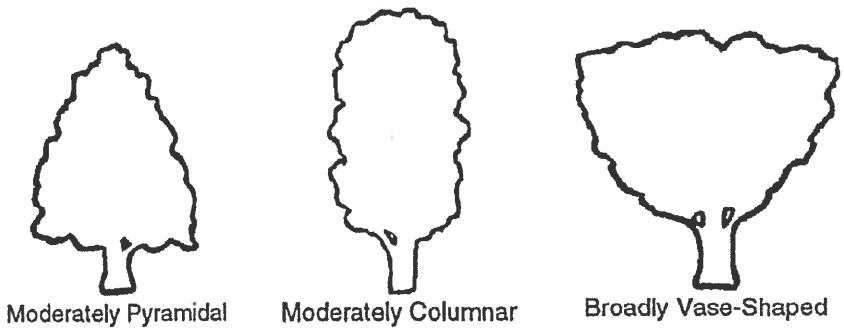


Figure 2-1
Tree Shapes for *Grow-in* (vertical gap) Test

Horizontal gap

Category 4, blowing together, represents a new category in NERC Reliability Standard FAC-003-3 relating to sustained outages caused by vegetation and applicable lines blowing together (mostly horizontal displacement) when both are within the ROW. For these tests, the important factor is the shape facing the conductor from the side. These will be tests to determine horizontal flashover distances. Two tree shapes are identified for testing:

1. Deciduous trees often have a decurrrent (random) form. These trees may enter the MVCD space with a **single branch**.
2. Conifers (spruce, fir, pine) typically have a well-defined central leader. The shape facing the conductor will be broad and flat. Their shape is described as **moderately columnar**.

Schematic representations of these tree shapes are presented in Figure 2-2.

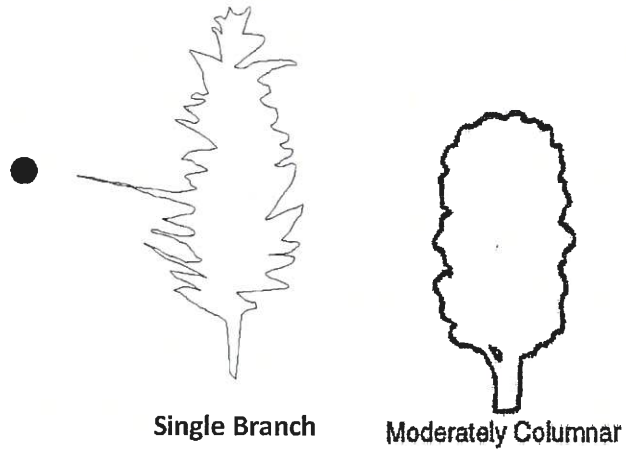


Figure 2-2
Tree Shapes for Blowing Together (horizontal gap) test

Test Timing

A review of NERC-Reported tree outages for the period of 2005 through 2010 (Table 2-1 and Figure 2-3) indicates that essentially all NERC tree-related outages occur after the early growth period in the spring, and end before the leaves fall from the trees. For this reason the testing was scheduled for this same time of the year.

Table 2-1
NERC-Reported Tree Outages by Month

When	Voltage	Species	Inferred Shape
9-Aug-10	500kV	black willow	columnar
2-Aug-09	345kV	American elm	columnar
3-Jun-10	unknown	unknown	unknown
2-Jun-08	unknown	willow	columnar
1-Aug-08	345kV	unknown	unknown
8-Aug-07	500kV	unknown	unknown
unknown	230kV	apple tree	columnar
1-Jun-08	500kV	eastern cottonwood	columnar
unknown	unknown	unknown	unknown
31-Aug-07	230kV	almond, orchard	broad
18-Jul-07	230kV	cottonwood	columnar
28-Jul-07	230kV	unknown	unknown
unknown	230kV	cherry	broad
unknown	230kV	Bradford pear	broad
22-Aug-07	230kV	unknown	unknown
16-Aug-07	230kV	pine	pyramidal
5-Jul-05	765kV	black locust	columnar
5-Jul-05	230kV	unknown	broad
12-Jul-05	230kV	unknown	unknown

When	Voltage	Species	Inferred Shape
17-Jul-05	345kV	unknown	unknown
9-Jul-05	500kV	unknown	unknown
19-Aug-05	500kV	Silver maple	columnar
12-Jul-05	345kV	unknown	unknown
27-Jul-05	500kV	Lombardi poplar	pyramidal
12-Sep-05	230kV	unknown	broad
4-Jun-05	345kV	unknown	unknown
6-Jun-05	345kV	unknown	unknown
30-Jun-05	230kV	unknown	unknown
6-Jun-05	unknown	yard tree	broad
25-May-05	500kV	Visual screen	broad
14-Jun-05	500kV	aspen	pyramidal
26-Jun-05 *	345kV	plantation	broad
26-Jun-05 *	345kV	brush	pyramidal
26-Jun-05 *	345kV	unknown	unknown
26-Jun-05 *	230kV	unknown	unknown
26-Jun-05 *	230kV	yard tree	broad
26-Jun-05 *	230kV	unknown	unknown

* June 26 = assumed date by NERC Vegetation Committee

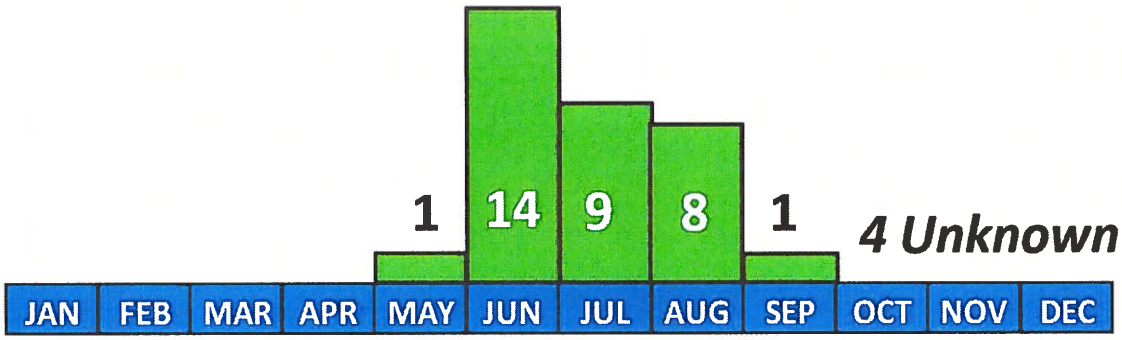


Figure 2-3
Monthly Distribution of NERC-Reported Tree Outages

Definition of Test configurations

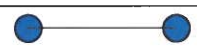
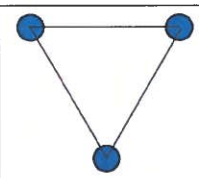
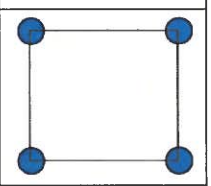
The test configurations comprise the following items

- Energized electrode definition
- Grounded electrode definition
- Gap size

Energized electrode definition

The energized electrode is designed to represent the phase conductor or phase conductor bundle as appropriate. As is common for high-voltage testing, the conductors are represented by aluminum tubes, which were chosen because of their rigidity and light weight which facilitated the construction of a repeatable test setup. The chosen conductor bundles representative of each of the different system voltage levels being tested is presented in Table 2-2.

Table 2-2
Bundle definitions for each of the system voltage levels

Nominal Voltage	230 kV	345 kV	500 kV	765 kV
Bundle (# conductors per phase)	1	2	3	4
Sub-conductor spacing (m)	n/a	18 inches	18 inches	18 inches
Bundle height above ground (NESC)	25.2 feet	29.0 feet	34.1 feet	42.7 feet
Conductor size (OD)	1.25 in	1.25 in	1.25 in	1.25 in
Bundle shape				

Note: There are different practices among transmission companies. These conductor sizes and spacing are selected to be representative of many designs yet specific to none.

Grounded electrode definition

The grounded electrode design must meet numerous requirements. It must:

- Simulate the electric field (E-field) distribution around natural vegetation under and beside a transmission line,
- Account for the worst case permittivity and conductivity of different trees species and environmental conditions.
- Have a repeatable electrode geometry over multiple applications of switching impulses, some of which will result in flashover.

Based on these principles three basic grounded electrode configurations were defined.

1. Cut trees with grounded metal rod
2. Cut trees with a wooden dowel on conductive center rod
3. Natural Vegetation

Cut trees with grounded metal rod

Figure 2-4 illustrates how the rod was placed in the approximate center of natural vegetation. The tree was to be freshly cut and supported mechanically. The base of the tree was placed in a grounded bucket of tap water to slow moisture loss and to facilitate electrical grounding. The metal rod (diameter 1.25") was lashed to the tree with rope.

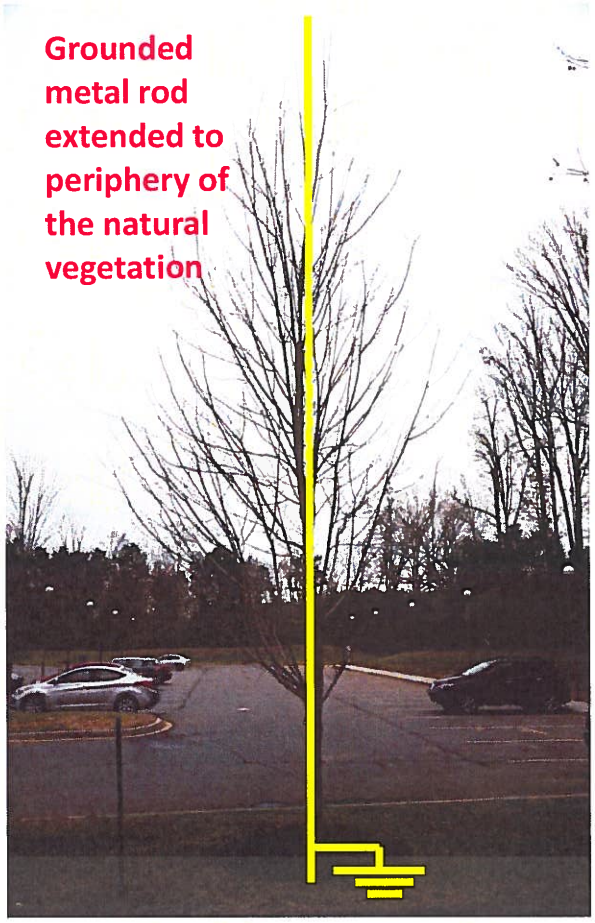


Figure 2-4
Sketch of a grounded metal rod placed in the center of natural vegetation

The tip of the metal rod was flush with the outer edge of the vegetation, protruding only enough (about 1") such that there was no natural vegetation closer to the energized conductor/bundle. This positioning was chosen as the worst case based on the results of preliminary testing performed to determine the effect of the length of the rod exposed above the vegetation on the CFO of the gap. The results of these preliminary tests are presented in Table 2-3.The bottom of the metal rod was grounded solidly to a grounding plate to provide a current path back to the impulse generator.

Table 2-3
Results of preliminary tests performed to determine the positioning of the rod with respect to the foliage.

					Nominal Voltage
					345 kV
				Bundle (# of conductors per phase)	2
				Sub-conductor spacing [inch]	18
				Bundle height above ground (NESC) [Feet]	29.0
				Conductor size (Outer diameter) [inch]	1.25
				Bundle shape	
				Gap [feet]	3.39
				Gap [m]	1.03
#	**Orientation**	**Shape**		**Description**	**Determined Gap Factors (CFO kV)**
1.1	Vertical / Grow-in	Vase		Rod tip approximately flush with the tree foliage	1.36 (528)
				4" of rod exposed above the tree foliage	1.43 (555)
				24" of rod exposed above the tree foliage	1.63 (634)

Note: All flashover values are corrected to standard atmospheric conditions as per IEEE std 4.

Natural vegetation with wooden dowel on conductive center rod

This configuration is similar to that described in Chapter 3; the only difference being that the last meter (3.28 feet) of the metal rod used for the "metal rod" tests was replaced with a wooden dowel. Some considerations taken in the development of this electrode design were:

- The replaceable wooden dowel would account for the lower (with respect to the metal rod in Test 1) conductivity and permittivity of the final branch in the flashover path. Although lower values would be achieved, it could not be guaranteed that the selected wood type is the worst case.
- The replaceable wooden dowel / metal rod interface needed to facilitate easy replacement with a sample of similar dimensions, conductivity and permittivity.
- The replaceable wooden dowel had to be consistently electrically bonded to the conductive electrode. A one foot section of angle iron was bonded to the conductive electrode with nuts and bolts. The wooden dowel was screwed into the angle iron. Conductive paste was applied to ensure a good connection between the wooden dowel and the angle iron.

To meet all of these requirements a replaceable wooden dowel was attached to the end of the conductive rod as shown in Figure 2-5. The wooden dowel extended one meter (3.28 feet) in length from the metal rod (Figure 2-5). The cross section of the wooden dowel is a 1 inch square.

The electric field distribution of the configuration employing the wooden section provides a very close approximation to that of the natural vegetation. Appendix A illustrates the E-field modeling results. The proposed definition of the replaceable wooden sections is provided in Appendix B.

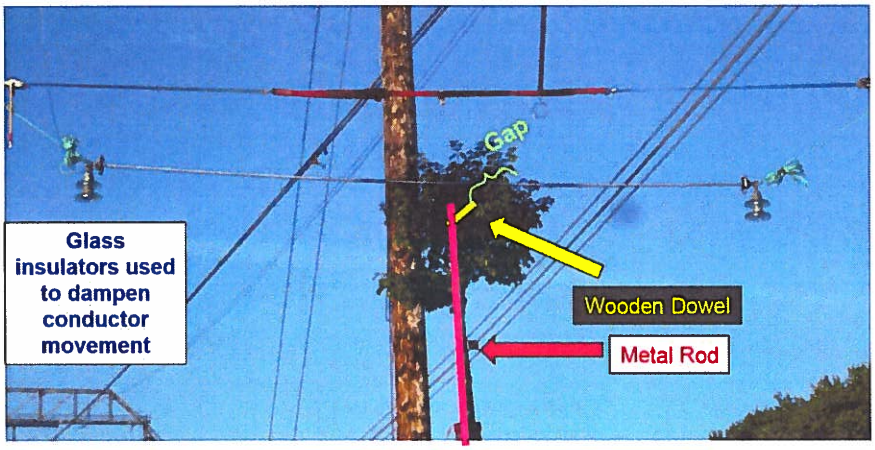


Figure 2-5
Wooden Dowel Test Set up for Columnar, 230 kV, Horizontal Gap

During the impulse testing, the "wooden dowel" was replaced an identical sample after each flashover. The reason for the replacement is that the electrical, and possibly dimensional, properties of the section are altered by the flashover. Great care was taken in fabrication of the replaceable wooden dowels to ensure uniformity between samples. As shown in Figure 2-6, the wood dowels used in this test were sawn from recently harvested green logs from a single tree in the genus Populus (e.g. cottonwood, aspen). Care was taken to select sawn specimens with relatively uniform wood characteristics. Test specimens were kept in a cool moist environment prior to use.

Figure 2-6
Freshly Cut Wooden Dowels

Natural Vegetation

The impulse withstand tests on the natural vegetation were performed on trees that were specifically planted for this purpose on the terrain of EPRI's HV test site in Lenox, MA. The following trees were available:

- 50 hybrid poplar whips which were planted in the spring of 2009

- An additional group of approximately 50 naturally occurring native stems (aspen, birch, cherry) were selected and retained
- 10 sugar maples (12 feet to 15 feet in height) and 11 trees (8 foot in height) of other species including Norway maple, red maple, ash and cherry were also planted in the fall of 2011– see Figure 2-7.

Figure 2-7
Image of the planted trees under the UHV span which were utilized for the natural vegetation withstand tests.

The switching impulse withstand tests were done to these trees in situ without any additional measures taken with regards to providing a conductive ground return path for the current on flashover.

Details of the actual test setups utilized for the tests to the natural vegetation are provided in Chapter 5.

Gap Size

The shortest distance from the bottom/side of the conductor bundle to the top of the grounded conductive rod is defined in Table 2-4.

Table 2-4
Gap sizes for different system voltage levels being tested

Nominal Voltage	230 kV	345 kV	500 kV	765 kV
Gap (feet)	3.22	3.39	5.45	8.61
Gap (m)	0.98	1.03	1.66	2.62

Note: these distance were derived from FAC-003-3 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD) For Alternating Current Voltages between 1000 and 2000 feet above sea level. (The Lenox test site is 1200 feet above sea level.)

To minimize interference with the electric field profile between the simulated conductor bundle and the tree, the connection from the impulse generator to the bundle was made as far as practical from the Artificial Vegetation Configuration as shown conceptually in Figure 2-8 and Figure 2-9. The length of the conductors/pipes was chosen to be sufficient to minimize any end effects.

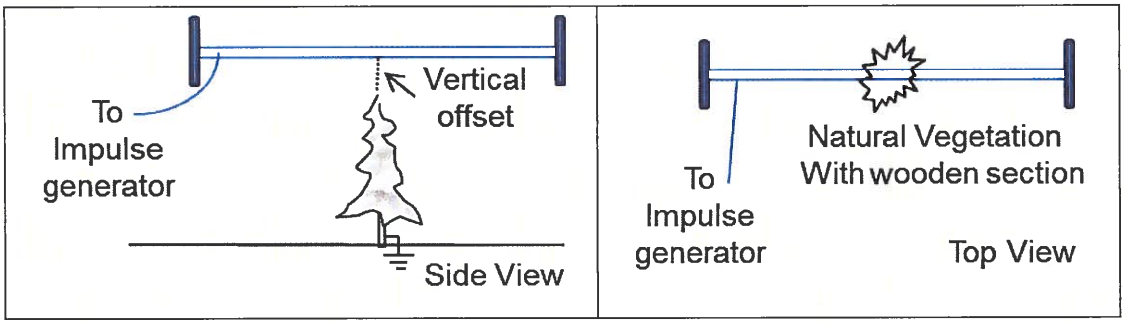


Figure 2-8
Connections to the conductor bundle for the Grow-in switching impulse test (i.e. vertical gap to artificial vegetation)

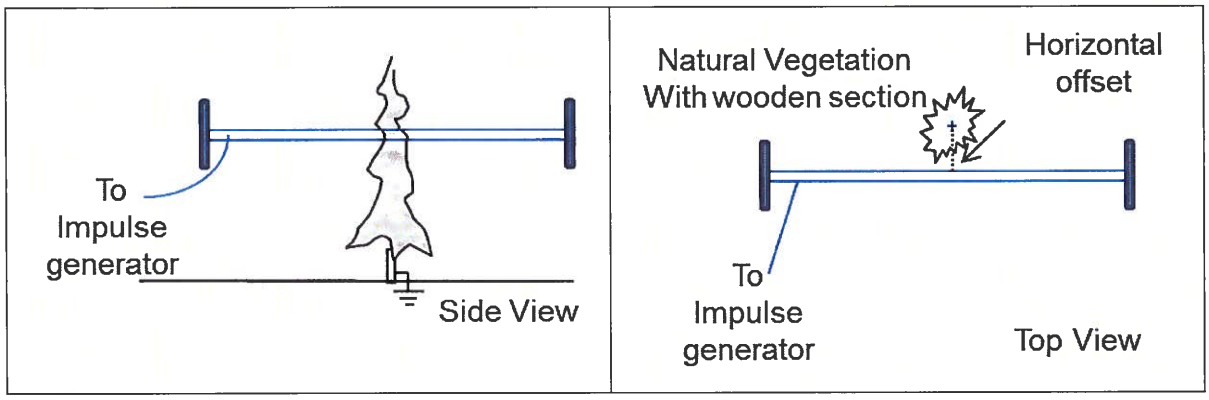


Figure 2-9
Connections from impulse generator to the conductor bundle for the Blow-in switching impulse test (i.e. horizontal gap to artificial vegetation)

Definition of test circuit

Applicable Standards

IEEE Std 4-2013.

Wave shape

The tests were performed with a switching impulse as defined in IEEE Standard 4. The definition of the wave parameters are presented in Figure 2-10. Oscillations and overshoot on the impulse wave were less than 5% of the voltage peak.

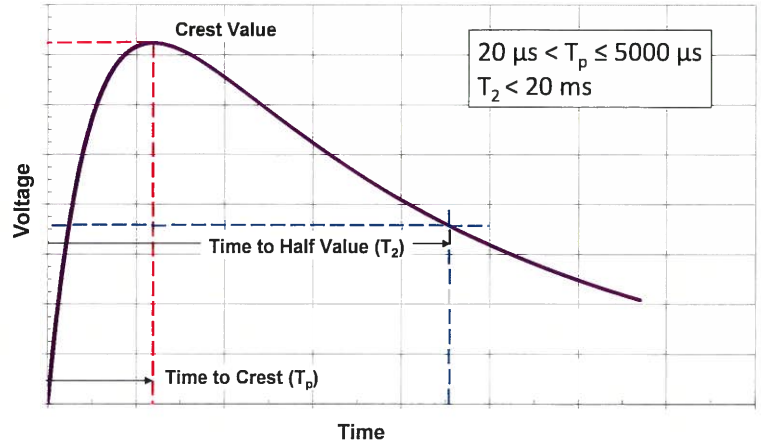


Figure 2-10
Definition of the switching impulse wave shape as per IEEE Standard 4

The switching impulse wave parameters, T_p and T_2 were selected to correspond to the critical wave shape, which is the impulse shape that results in the lowest expected switching impulse flashover strength of the vegetation clearances tested.

As shown in Figure 2-11, the time to crest of the switching impulse, T_p, has a significant influence on the 50% flashover voltage (i.e. CFO) of gaps. Based on the data presented in Figure 2-11 it is expected that the critical wave front for the gap sizes considered (i.e., 3.22 feet to 8.61 feet) will be in the order of 60 microseconds to 130 microseconds (µs). Considering the gap sizes being tested and the limitations of the impulse generator, a single time to peak value, T_p, of approximately 100 µs was utilized for all tests.

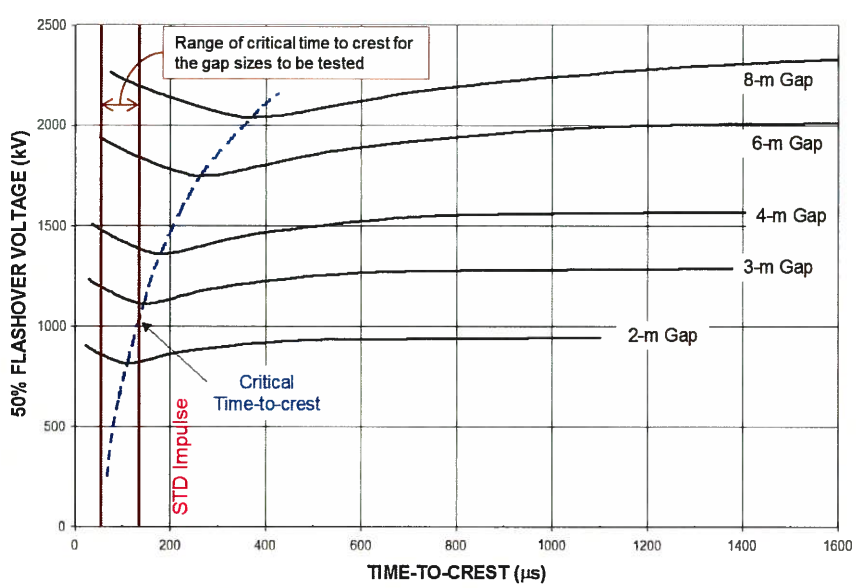


Figure 2-11
Selection of the time to peak to correspond to the critical wave front

The time to half value, T_2, does not significantly impact the switching impulse strength and was selected to be approximately 2500 μs, which corresponds to that of the standard switching impulse wave shape.

Marx Generator setup

The switching impulse tests were performed with a conventional Marx generator circuit as shown in Figure 2-12. The 28 stage impulse generator at the EPRI High-Voltage laboratory at Lenox, MA has the following internal parameters:

- Capacitance per stage: 0.5 micro-farads (μF)
- Self-inductance per stage: 3.64 micro-henries (μH)
- Internal resistance per stage: 0.2 ohms (Ω)

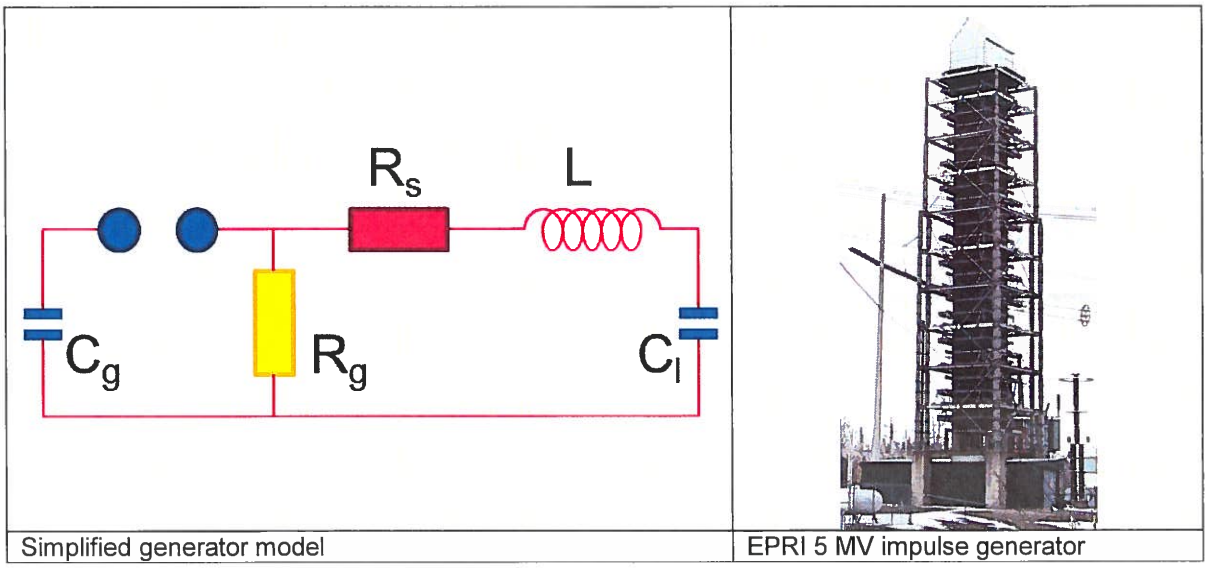


Figure 2-12
Test Circuit for Lightning Impulse Tests

The number of stages, damping resistance (R_s), and discharge resistance (R_g) were selected to produce the critical impulse wave as defined in the previous section with the following tolerances:

- Time to peak (T_p): 100 μs ± 20%
- Virtual time to half-value (T_2): 2500 μs ± 60%

Before each test commenced a test impulse was applied to the test object to verify that the applied impulse conforms to the parameters specified. The peak magnitude of this impulse was well below the expected CFO.

Test equipment

The following equipment was utilized for the switching impulse testing:

- 5 MV Impulse generator

- HV divider
- Weather station installed at height of gaps under test
  (Air pressure, temperature, humidity, wind speed and direction)
- Digital storage oscilloscope with ability to extract the impulse wave shape parameters
- A camera to capture impulse flashover paths

Test Ambient Conditions

The tests were performed under dry conditions. This means:

- No precipitation of any kind was allowed.
- Relative humidity was less than 80%
- The ratio of the absolute humidity (h) to the relative air density (δ) could not exceed 15 g/m^3.
- The ambient temperature was between 0°C (32° F) and 40°C (104°F).
- Wind speed: The relative distance between electrode and tree tip must not vary significantly. This was ensured by monitoring the wind speed. If necessary, the conductive electrode was stabilized with rope or insulators approximating an inverted V.

3
SWITCHING IMPULSE TESTS: CUT TREE WITH GROUNDED METAL ROD

Objectives

The objective is to determine the gap factor for various tree shapes over the full range of transmission system voltages considered.

Approach

Switching impulse testing was performed to determine the critical flashover voltage (CFO) from phase conductors to artificial vegetation configurations. The artificial vegetation employed in this chapter was comprised of the full crown of a recently harvested (i.e. cut) tree with fresh foliage. The intent was to replicate the permittivity of natural vegetation including stems, branches, twigs and leaves of a vibrant tree. The crown included a grounded metal rod that was used as the ground electrode. The cut surface of the recently harvested crown was placed in a grounded tub of tap water. It was initially intended that foliage would be wetted to reduce moisture loss due to evapotranspiration. The gap factor (k_g) was calculated based on test results and compared against the value utilized in the MVCD calculation with FAC-003-3.

Test location and connections to test object

The artificial trees were set up and tested in the impulse test yard as is indicated in Figure 3-1.

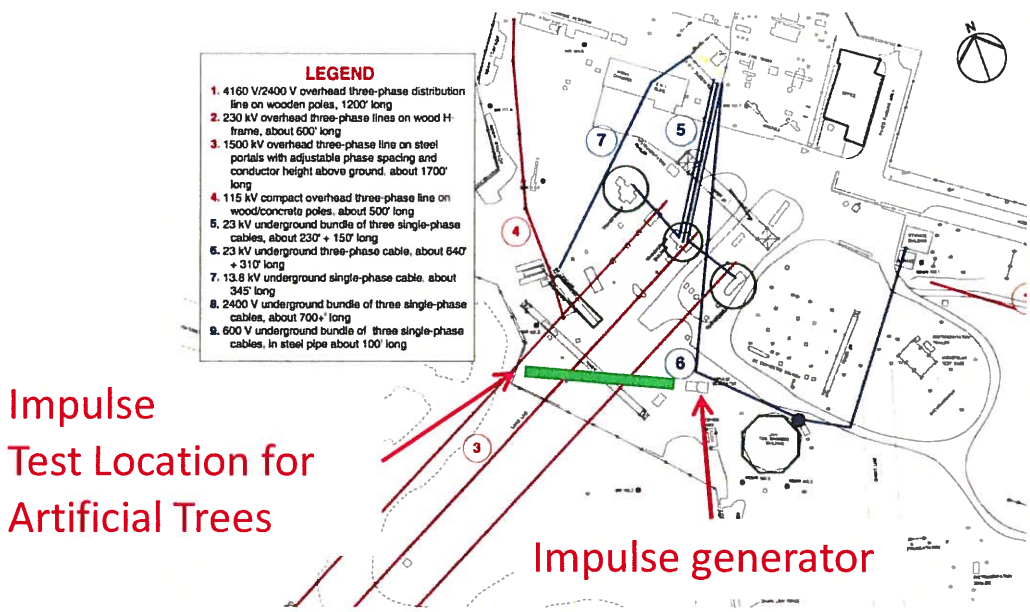


Figure 3-1
Test Location for Artificial Trees

All support structures (i.e., artificial vegetation configuration and dead ends) were bonded to the impulse generator ground with low surge impedance connections.

Example images of the test setup are shown d in Figure 3-2. The grounded metal rod (diameter 1.25") was placed in the center of freshly cut tree, with the rod adjacent and parallel to its main trunk. The top tip of the grounded metal rod was flush with the periphery of the vegetation, protruding only enough (i.e. about 1") such that there is no natural vegetation closer to the energized conductor/bundle.

Figure 3-2
Photograph of test set up. Vertical clearance set using winch.

To keep the trees fresh, the cut surface of the recently harvested crown was placed in a tub of tap water. The foliage was to be wetted down before each test, to simulate post rainy conditions. That step was omitted because it was assumed that the freshly cut trees were sufficiently wet for the testing.

The trees remained fresh for approximately two days. When the leaves showed any sign of wilting, the tree was replaced for the next series of tests. Best efforts were made to harvest trees of similar height and foliage width. However, it was impossible to find exact matches. This proved to be an important factor in the test result analysis.

Test Procedure

The impulse flashover strength of the various test configurations was determined through the Multiple Level Method. With this test method a specific number of impulses are applied at several voltage levels to obtain an estimation of the probability for flashover at each of the voltage levels. This data is then analyzed with the method of maximum likelihood to obtain estimates of the CFO (or U_{50}) and standard deviation of the flashover probability distribution. For the testing of the MVCD clearances the following parameters were used:

- At least 10 impulse applications per voltage level

- The step size shall be selected to achieve at least 4 voltage levels between full withstand and complete flashover

An example of a typical test sequence according to the multiple level method is shown in Figure 3-3.

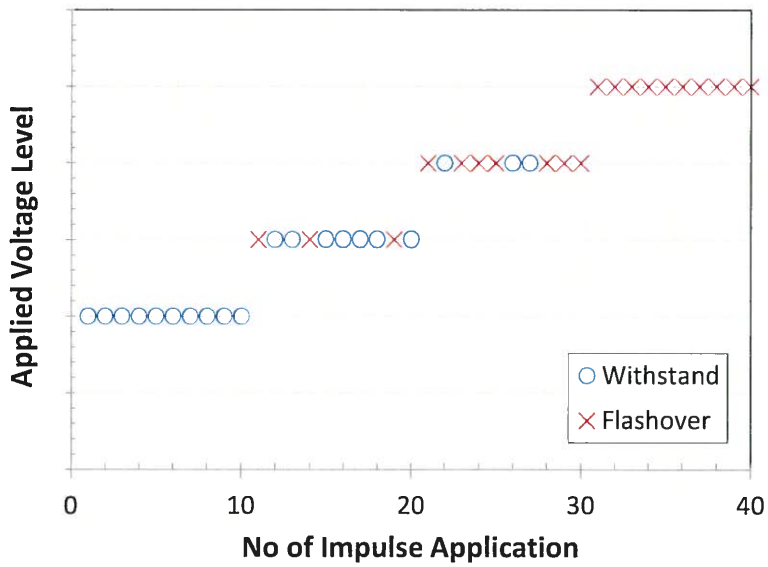


Figure 3-3
Example of a switching impulse test sequence according to the multiple level method (MLM)

The test operation was controlled from the Lenox Test Building. A computer system in the Building captured the wave shape and other test parameters (Figure 3-4).

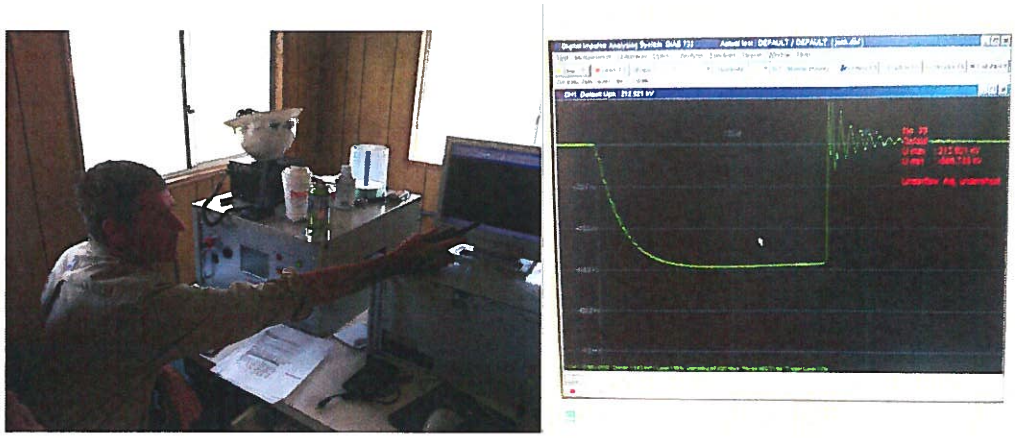


Figure 3-4
Test Cabin and Display

Evaluation of Results

The test results were evaluated as follows:

- For each series of flashover tests, the results were analyzed with the maximum likelihood method to obtain an estimate of the CFO and standard deviation of the particular gap flashover characteristic.
- The estimated CFO values were corrected to standard atmospheric conditions per the requirements of IEEE STD 4. The gap factor (k_g) was calculated and documented for each series of tests. The tree shape and voltage class yielding the lowest gap factors were noted, and used in the identification of the configuration would be used in the tests on natural vegetation with a wooden dowel on conductive center rod (Test series 2) described in Chapter 5, The tree shapes and voltage class yielding the two lowest used in the withstand test (Test 3) in Chapter 6.

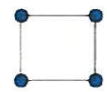
Results

Tests Performed

The flashover tests performed as part of test series 1 is summarized in Table 3-1. It shows that the grow-in tests were performed for three tree shapes in vertical offset, and the blow-in tests were performed for two tree shapes in horizontal offset. For these five configurations the tests were performed at four voltage classes, namely 230 kV, 345 kV, 500 kV, and 765 kV. This represents a series of 20 tests. The table also show the order in which testing was performed by assigning each test a unique test sequence number. The order in which the tests were performed was designed to be efficient, avoid excess removal of trees, as well as to meet conflicts, such as inclement weather or scheduling conflicts with other facility projects.

Additional tests were performed above and beyond the test plan. In this series of tests one additional test was performed to verify that the equipment was operating appropriately. This test comprised of a series of impulse events to a fully grounded rod without vegetation and a vertical separation to the conductor. This test showed that the flashover of a 39" (0.98 m) conductor to rod only (i.e. without the tree) gap was in the order of 600 kV. This corresponds to a gap factor of approximately 1.6 which falls within the range expected for a conductor to lower rod gap (see Table 1-1).

Table 3-1
Overview of program for the switching impulse tests on a cut tree with grounded metal rod.

				Nominal Voltage			
				230 kV	**345 kV**	**500 kV**	**765 kV**
Bundle (# of conductors per phase)				1	2	3	4
Sub-conductor spacing [inch]				n/a	18	18	18
Bundle height above ground (NESC) [Feet]				25.2	29.0	34.1	42.7
Conductor size (Outer diameter) [inch]				1.25	1.25	1.25	1.25
Bundle shape							
Gap [feet]				3.22	3.39	5.45	8.61
Gap [m]				0.98	1.03	1.66	2.62
#	**Orientation**	**Shape**		**Test sequence #**			
1.1	Vertical / Grow-in	Vase		2	5	8	11
		Columnar		3	7	9	12
		Pyramidal		1	6	10	13
1.2	Horizontal / Blow together	Columnar		14	16	18	20
		Single branch		15	17	19	21

Note: Test with sequence number 4 is not included in the table as it was one of the additional tests performed. For details refer to the paragraphs below.

Example of Analysis

To provide an indication of the analysis employed to determine the gap factors, a detailed view of the results of Test 1.1 is shown below. This refers to a test of the vertical clearance from a 230 kV conductor to a pyramidal-shaped tree. During this test 41 switching impulses were applied to the test object at four different voltage levels. The sequence of impulse applications during the test is shown graphically in Figure 3-5 and the same results are summarized in Table 3-2.

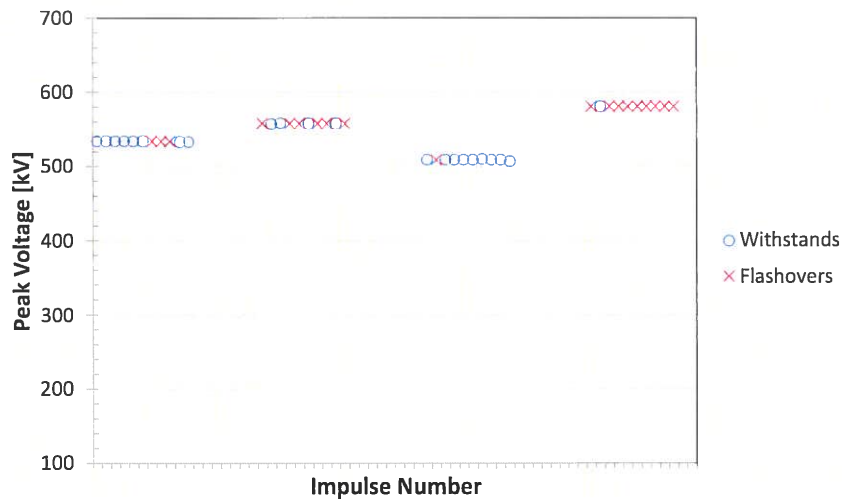


Figure 3-5
Impulse Results for Test sequence # 1, of test series 1-1 (0=withstand, x = flashover)

Table 3-2
Impulse Results Test 1, Sub-test 1

Voltage level [kV]	Corrected voltage level [kV]	No of Withstands (WS)	No of Flashovers (FO)	Total Number of impulses applied	% FO
509	496	9	1	10	10
534	521	8	3	11	27
558	544	4	6	10	60
581	565	1	9	10	90

An example of a flashover to the cut tree grounded metal rod is shown in Figure 3-6.

Figure 3-6
Example of a flashover to the cut tree with grounded metal rod.

The test data points and the fitted distribution function of the flashover probability are shown graphically in Figure 3-7.

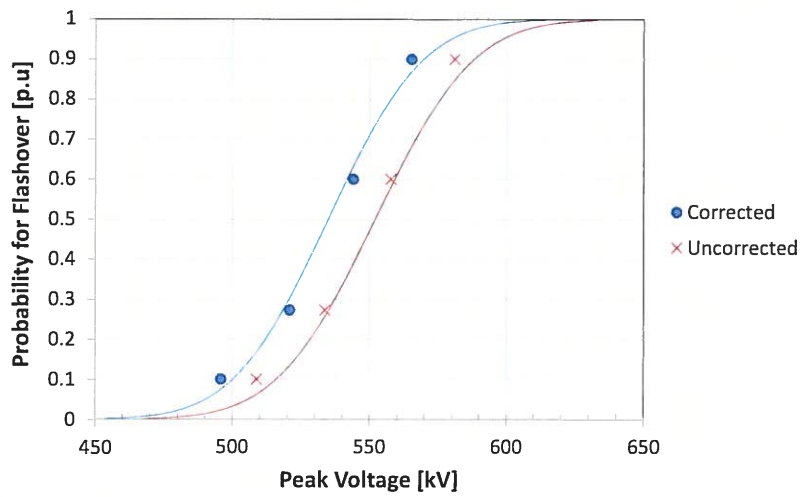


Figure 3-7
Probability of flashover for Test series 1, Test # 1. Curves are shown for both the uncorrected results and the results corrected for atmospheric conditions.

These data points were used to estimate the critical flashover voltage (CFO) and its standard deviation. The CFO is the voltage level with a 50% flashover probability. The results of this analysis are presented Table 3-3.

Table 3-3
Estimate of the CFO, U_{50}, of the vertical clearance from a 230 kV conductor to a pyramidal-shaped tree.

Test # 1 of Test Series 1.1		As tested		Corrected to Standard Conditions	
		CFO [kV]	Std. dev.[kV]	CFO [kV]	Std. dev.[kV]
STD Impulse	95% Conf. Min	531	16	518	15
	Estimate	**549**	**28**	**535**	**27**
	95% Conf. Max	569	73	555	71

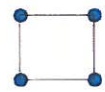
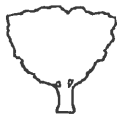
The CFO, at sea-level, is therefore determined as 535 kV. This CFO is now compared to that of a rod-plane gap with the same gap length of 3.22 feet (0.98 m) which according to the Gallet equation should have a CFO of 371 kV. The gap factor is therefore calculated as $k_g = 535/371 = 1.44$.

A similar analysis was performed for each of the 20 possible configurations considered in Test series 1.

Calculated Gap factors

The resulting gap-factors are displayed in Table 3-4. The lowest and second lowest gap-factors are noted. The lowest gap factors for Test series 1.1 (Test #2) and 1.2 (Test #14) respectively are highlighted with bold typeface.

Table 3-4
Test results for all grounded metal rods

				Nominal Voltage			
				230 kV	**345 kV**	**500 kV**	**765 kV**
Bundle (# of conductors per phase)				1	2	3	4
Sub-conductor spacing [inch]				n/a	18	18	18
Bundle height above ground (NESC) [Feet]				25.2	29.0	34.1	42.7
Conductor size (Outer diameter) [inch]				1.25	1.25	1.25	1.25
Bundle shape							
Gap [feet]				3.22	3.39	5.45	8.61
Gap [m]				0.98	1.03	1.66	2.62
#	**Orientation**	**Shape**		**Determined Gap Factors (CFO kV)**			
1.1	Vertical / Grow-in	Vase		**1.15 (427)**	1.29 (502)	1.16 (670)	1.21 (1011)
		Columnar		1.19 (442)	1.42 (551)	1.16 (671)	1.24 (1029)
		Pyramidal		1.44 (535)	1.34 (522)	1.27 (731)	1.43 (1191)
1.2	Horizontal / Blow together	Columnar		**1.02 (379)**	1.17 (455)	1.21 (701)	1.25 (1039)
		Single branch		1.44 (536)	1.39 (539)	1.35 (781)	1.41 (1173)

Note: All flashover values are corrected to standard atmospheric conditions as per IEEE std 4.

The results in Table 3-4 show a significant variance in gap factor, even for the same tree shape. This highlights the inaccuracy of applying the gap factor approach to dimensioning clearance distances. The results suggest that the gap factor may be strongly influenced by relatively small changes in the gap configurations. This is especially so for the smaller gap sizes tested.

4
SWITCHING IMPULSE TESTS: CUT TREE WITH WOODEN DOWEL ON CONDUCTIVE ROD

Objective

The intent of the wooden dowel test was to demonstrate that the switching impulse strength of a gap between an energized conductor and a "wooden branch end electrode" is greater than that of an identical gap comprising the energized conductor and a "metal end electrode." From this it may be inferred that flashover to natural vegetation will require a higher overvoltage than flashover to a grounded metal electrode (as was tested in Chapter 3). It may also provide an estimate of the degree of conservatism present when the metal rod is used in place of a wooden electrode. Lastly, this test also provides a statistical view of the flashover probability for natural vegetation, albeit for one configuration only.

Approach

Switching impulse testing was performed to determine the critical flashover voltage (CFO) from phase conductors to one of the vegetation configurations. Essentially the same test setup was used as in Chapter 3 but the metal rod was replaced by a combined electrode comprising a metal rod base fitted with a meter long wooden dowel. The determined gap factor (k_g) was compared against the value utilized obtained in Test series 1 (Chapter 3) for the same gap configuration and the MVCD calculation with FAC-003-3.

A single test was performed for the tree shape, offset direction, and voltage class that yielded the lowest gap factor in Test series 1 (Chapter 3). This was the blow together (horizontal) 230 kV configuration to a columnar tree (Test 1.2 Test # 14).

Test Location and Connections to Test Object

The cut tree with wooden dowel test location was the same as used for Test Series 1 as shown in Figure 4-1.

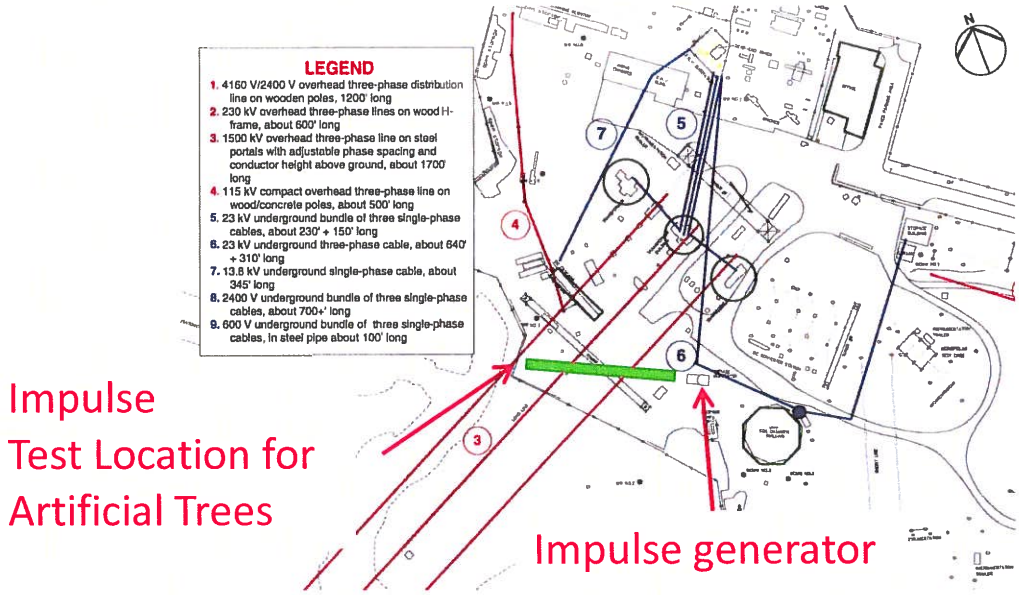


Figure 4-1
Test Location for Artificial Trees

A directly grounded metal rod with an outer diameter of 1.25", was placed in the center of freshly cut natural vegetation. A freshly cut dowel was fixed to the rod and laid horizontally to the outside of the tree. The tip of the wooden dowel was flush with the periphery of the vegetation, protruding only enough (i.e. 1") such that there is no natural vegetation closer to the energized conductor/bundle.

All support structures (i.e., center metal electrode and dead ends) were bonded to the impulse generator ground with low surge impedance connections.

Testing Procedure

The impulse flashover strength of the test configuration was determined by applying the Multiple Level Method. With this test method a specific number of impulses are applied at several voltage levels to obtain an estimation of the probability for flashover at each of the voltage levels. This data was then analyzed with the method of maximum likelihood to obtain estimates of the CFO (or U_{50}) and standard deviation of the flashover probability distribution.

The following test parameters were used:

- At least 10 impulse application per voltage level
- A step size selected to achieve at least 4 voltage levels between full withstand and complete flashover

An example of a typical test sequence according to the multiple level method is shown in Figure 3-3.

Evaluation of the results

The test outcome was evaluated as follows:

- The test results were analyzed with the maximum likelihood method to obtain an estimate of the CFO and standard deviation of the particular gap flashover characteristic.
- The estimated CFO values were corrected to standard atmospheric conditions per the requirements of IEEE STD 4.
- The gap factor (k_g) was calculated and documented for the tests. This value is then compared with that obtained for the test cut tree with grounded metal rod performed on the same configuration.

Test Performed

The test program for the switching impulse tests on periphery of cut tree with wooden dowel on conductive center rod is summarized in Table 4-1.

Table 4-1
Overview of program for the single set of switching impulse tests on cut tree with wooden dowel on conductive center rod.

		Nominal Voltage		**230 kV**
		Bundle (# of conductors per phase)		1
		Sub-conductor spacing [inch]		n/a
		Bundle height above ground (NESC) [Feet]		25.2
		Conductor size (Outer diameter) [inch]		1.25
		Bundle shape		●
		Gap [feet]		3.22
		Gap [m]		0.98
#	**Orientation**	**Shape**		**Test sequence #**
2.0	Horizontal / Blow together	Columnar		23

Results

Calculated Gap factors

The resulting gap-factors are displayed in Table 4-2. It shows that the results of the wooden dowel test yielded a gap factor of 1.22. A direct comparison of results were made between the CFO calculated from the replaceable wooden section test results and those obtained in Chapter 3 (Test 1) using the fully grounded metal rod extended to the periphery of the foliage.

As compared to the same test with a grounded metal rod (gap Factor = 1.02), the wooden dowel test did serve the purpose of demonstrating that the metal rod is more conservative (Table 4-2). It may also be noted that, although higher, the gap factors resulting from the wooden dowel test was still well below the value of 1.3 used in the NERC standard.

Table 4-2
Test Results for Wooden Dowel as Compared to Fully Grounded Metal Rod

				Nominal Voltage	**230 kV**
				Bundle (# of conductors per phase)	1
				Sub-conductor spacing [inch]	n/a
				Bundle height above ground (NESC) [Feet]	25.2
				Conductor size (Outer diameter) [inch]	1.25
				Bundle shape	●
				Gap [feet]	3.22
				Gap [m]	0.98
#	**Orientation**	**Shape**		**Description**	**Determined Gap Factors (CFO kV)**
1.2	Horizontal / Blow together	Columnar		Metal rod	1.02 (379) [from Chapter 3]
2.0				Wooden dowel	1.22 (451)

Note: All flashover values are corrected to standard atmospheric conditions as per IEEE std 4.

Additional Tests

Two additional CFO tests were performed (Test 2.x) on the same cut tree configuration used for the testing in this chapter but with wooden dowel removed and the vertical part of the conductive center rod shortened. These tests were performed in an effort to determine if the tests with the wooden dowel provided any conservatism over a test with unmodified natural vegetation. The results of these tests are presented in Table 4-3.

Table 4-3
Summary of the results of the extra switching impulse test on a cut tree.

				Nominal Voltage	**230 kV**
				Bundle (# of conductors per phase)	1
				Sub-conductor spacing [inch]	n/a
				Bundle height above ground [Feet]	25.2
				Conductor size (Outer diameter) [inch]	1.25
				Bundle shape	●
				Gap [feet]	3.22
				Gap [m]	0.98
#	**Orientation**	**Shape**		**Description**	**Determined Gap Factors (CFO kV)**
2.x.a	Horizontal / Blow together	Columnar		Without dowel	1.19 (443)
2.x.b					1.23 (459)

Note: All flashover values are corrected to standard atmospheric conditions as per IEEE std 4.

Comparing the results presented in Table 4-3 with those of Test 2.0 (in Table 4-2) shows that there are no significant differences between the test with and without the presence of the dowel rod. It may thus be concluded that the tree with the dowel rod may be considered representative of unmodified natural vegetation.

5
IMPULSE VOLTAGE WITHSTAND TESTING ON NATURAL TREES

Objectives

The objective of the withstand tests on natural trees was to demonstrate that for the tree species, and tree shapes available in the Lenox test site, the MVCD calculation method is applicable. Two test series were performed at the configurations that yielded the two lowest gap factors in Test series 1:

- Columnar, 230 kV, horizontal gap
- Vase, 230 kV, vertical gap

Approach

Switching impulse withstand testing was performed on natural trees under the Lenox test line. Two trees, representative of the range of species and tree shapes were selected for testing based on the test results presented for Test Series 1 in Chapter 3.

Each withstand test was comprised of a minimum of fifteen switching impulses of the specified shape and polarity. The peak amplitude of the impulses was set to the overvoltage level given in the MVCD FAC003-2 Technical Reference. The ability of the gap to withstand the applied voltage is confirmed if one or none of the 15 applied impulses result in flashovers.

Test Location and Configuration

The natural trees were tested under the Lenox UHV span as is indicated in Figure 5-1. The conductors of the UHV span were used to connect the impulse generator with the test configuration.

The test configurations were made as similar as practical to that of the test of the cut trees documented in Test series 1, Chapter 3. The configurations are shown in Figure 5-2. The length of the simulated conductors was selected to be sufficient to minimize any end effects. The setup in the natural vegetation area was designed so that both the sag and lateral position of the lines could be controlled with respect to the trees chosen for testing.

All support structures (Test dead ends) were bonded to the impulse generator ground with low surge impedance connections.

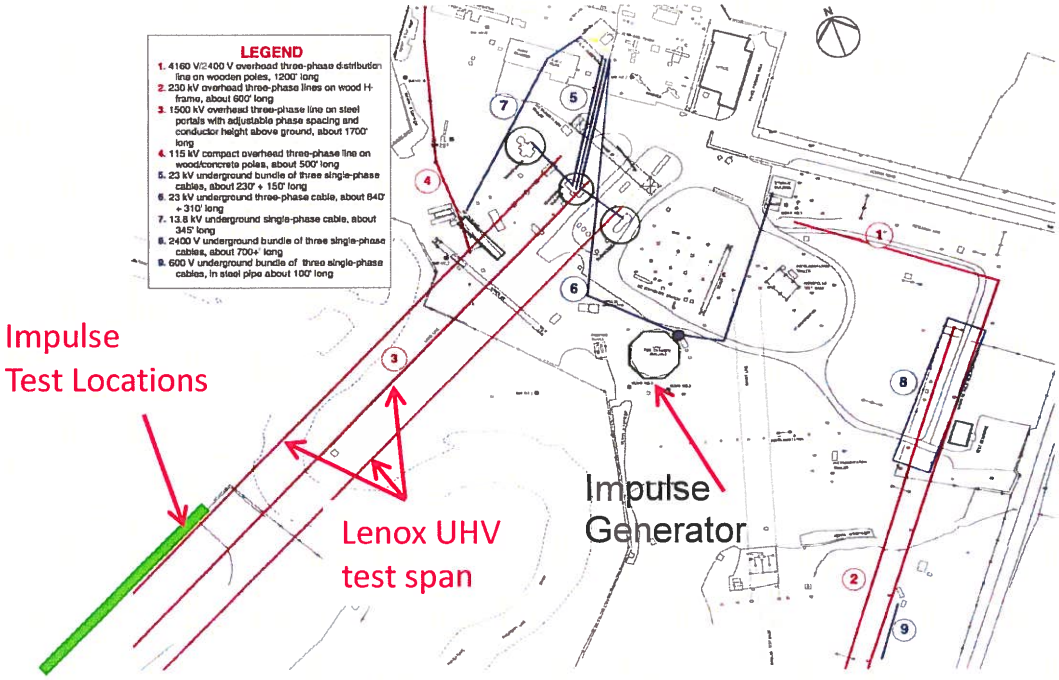
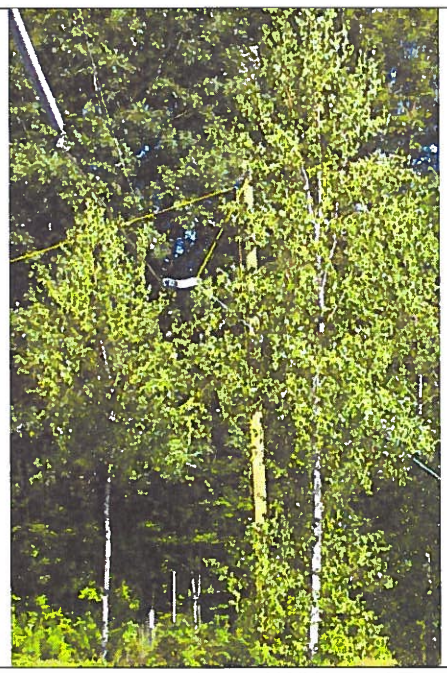
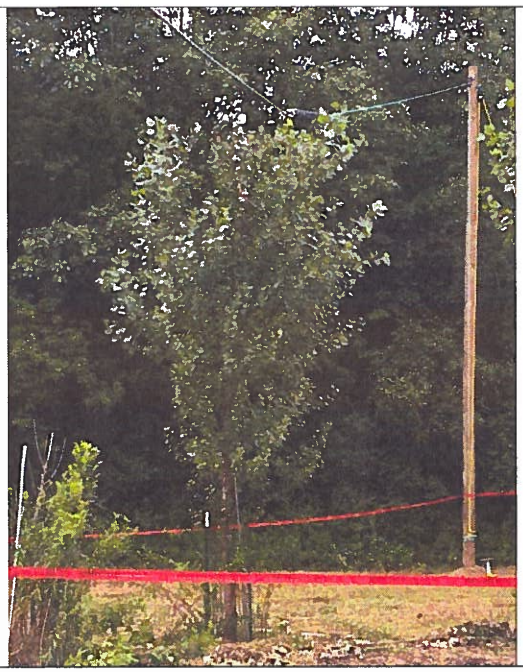


Figure 5-1
Test Location for Natural Trees



Columnar, 230 kV Horizontal Withstand Test



Grow-in Broadly Vase 230 kV Set Up

Figure 5-2
Views of switching impulse withstand test setups for natural trees.

Testing Procedure

The generator was set up to apply a critical switching impulse, as defined in Chapter 2. Due to the distance between the impulse generator and test objects, it was not possible to precisely measure the applied wave shape at the test site, however the wave shaping circuit was the same as that used to produce the previously defined critical switching impulse.

The test procedure followed the impulse withstand test procedure described in clause 8.4.2.2 (procedure B) of IEEE Standard 4-2013 as modified below. This modification is necessary as withstand for the MVCD is defined to be at -3 sigma and not at a 10% flashover probability (i.e -1.28 sigma) as in the standard.

1. 15 Switching impulses were applied to the test object at a voltage below the designated withstand voltage to allow for final adjustments to the impulse generator and test setup.
2. The withstand test was performed by applying a minimum of 15 switching impulses of the specified shape and polarity to the test setup. The peak amplitude of the impulses was identical and set to the overvoltage level given in the MVCD FAC003-2 Technical Reference. The ability of the gap to withstand the applied voltage would be confirmed if one or none of the 15 applied impulses result in flashovers.
3. Following the withstand test, a multiple level CFO test was performed on the natural tree. Based on the repeatability of the results it was determined that this test provided useful results the flashover currents caused minimal damage to tree.

Evaluation of the results

The test outcome is evaluated in a pass-fail manner. The test is failed if two or more of the 15 applied impulses resulted in flashover of the gap.

Results

Tests performed

The test program for the impulse voltage withstand testing on natural trees is summarized in Table 5-1.

Table 5-1
Overview of program for the switching impulse voltage withstand testing on natural trees.

Nominal Voltage				**230 kV (U_m: 242 kV)**
Bundle (# of conductors per phase)				1
Sub-conductor spacing [inch]				n/a
Bundle height above ground [Feet]				20.3
Conductor size (Outer diameter) [inch]				1.25
Bundle shape				●
Gap [feet]				3.22
Gap [m]				0.98
Applied Test Voltage [kV]				395 kV (2.0 p.u)
#	**Orientation**	**Shape**		**Test sequence #**
3.1	Horizontal / Blow together	Columnar		25
3.2	Vertical / Grow-in	Vase		24

Test outcome

Test 3.1: Columnar, 230 kV, Horizontal Configuration

The sequence of impulse applications during the test is shown graphically in Figure 5-3. The impulse applications that made up the withstand tests is indicated by the box in the figure.

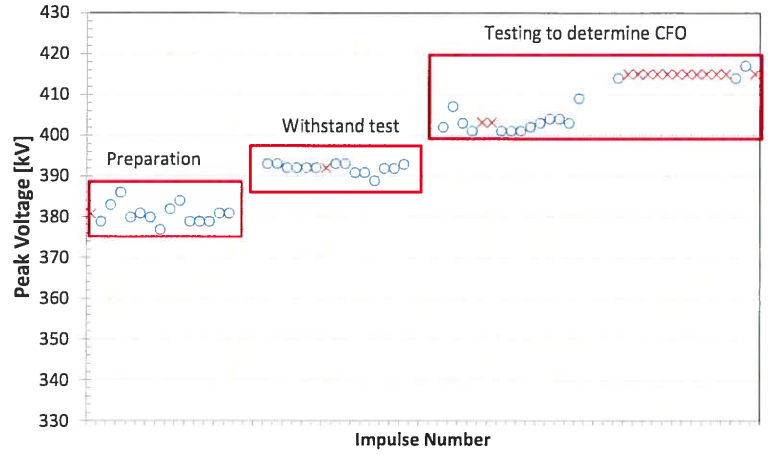


Figure 5-3
Impulse Results for the withstand test on the columnar, 230 kV horizontal configuration (test series 3.1) Note: 0=withstand, x = flashover

The withstand test resulted in one flashover of the 15 applied impulses. ***Therefore this gap passes the test.*** The additional flashover data was used to estimate the CFO and its standard deviation. The results of this analysis are presented in Table 5-2. The corrected CFO of 405 kV corresponds to a gap factor (k_g) of 1.09.

Table 5-2
Estimate of the CFO of the horizontal clearance from a 230 kV conductor to a columnar-shaped tree.

Test # 25 of Test Series 3		As tested		Corrected to Standard conditions	
		U_{50} [kV]	Std. dev.[kV]	U_{50} [kV]	Std. dev.[kV]
STD Impulse	95% Conf. Min	403	8	399	7
	Estimate	**409**	**13**	**405**	**12**
	95% Conf. Max	422	29	417	26

Comparison with Previous Test Results

A comparison of this test result to that of Test # 14 of Test Series 1.2 (see Figure 5-4 and Table 5-3) shows that the test on the natural tree resulted in a higher flashover strength than the test on the cut tree with grounded metal rod, thereby confirming the conservatisim of the approach followed.

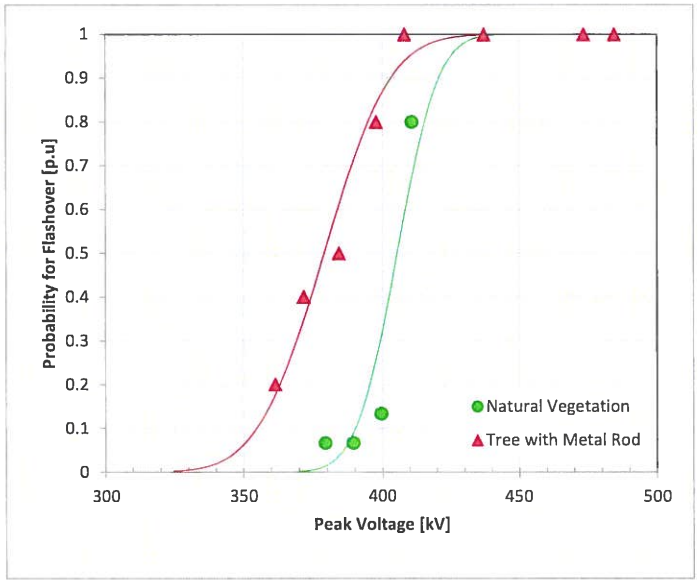
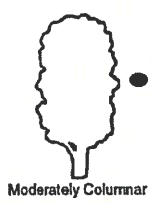


Figure 5-4
Probability for flashover for Test 3.2: Vase, 230 kV, Vertical configuration as compared with the results of Test #14 of Test Series 1.

Table 5-3
Test Results for Natural Vegetation as Compared to Wooden Dowel and Metal Rod

230 kV Test no.	Conductor Location	Tree shape Columnar	Material	Gap Size	Gap Factor	U_{50} (kV)
1.2			Metal Rod	38.6"	1.02	379
2	Horizontal / Blow Together		Wooden Dowel	38.6"	1.22	451
2.x			Tree Only	38.6"	1.23	459
3			Tree Only	38.6"	Passed	

Moderately Columnar

Up/Down Method
15 impulses

During this test series it was not possible to capture photographs of the flashovers to the tree. The resistance in the impulse current return path was very high, which severely limited the current flowing in the flashover. Consequently, the flashovers are not sufficiently luminous to capture on camera.

Test 3.2: Vase, 230 kV, Vertical Configuration

The target voltage level for the withstand test is 395 kV the initial setup of the generator resulted in a voltage of 383kV. This was the voltage level intended to be used for optimizing the generator setup prior to the withstand test.

The sequence of impulse applications during the test and the results are shown graphically in Figure 5-5. It was found for the first series of 15 impulses at 383 kV, marked "preparation" that more than the allowable number of flashovers (i.e. 12 flashovers out of 15 impulse applications) occurred.

Because of this unexpected result another set of 18 impulses were applied to the gap. These, marked as Withstand Test in Figure 5-5, resulted in 12 flashovers out of 18 impulse applications which confirmed that the withstand voltage of the gap lies below 383 kV. ***It is therefore concluded that the Vase, 230 kV, Vertical configuration fails the withstand test.***

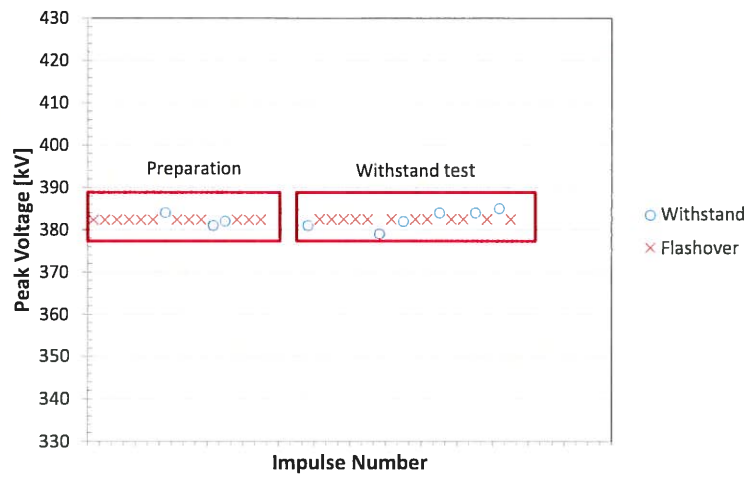


Figure 5-5
Impulse Results for the withstand test on the Vase, 230 kV, vertical configuration (test series 3.2)
Note: 0=withstand, x = flashover

During this test it was possible to take photos of the flashover path from the conductor to the top of the tree. Some examples are presented in Figure 5-6.

Figure 5-6
Flash overs to Vase, 230 kV, Vertical, Natural Vegetation

The probability of flashovers observed during the withstand tests (namely 12/15 = 0.8 (or 80%) and 12/18 = 0.67 (or 67%) respectively) falls significantly below that which may be expected from the results of Test Series 1 on the same configuration, but with a metal rod, (Test # 2 of Test Series 1). This is illustrated in Figure 5-7. From the results of a series of additional tests – see the last section of this chapter – it is concluded that the lower flashover strength of the natural tree may be ascribed to its larger size (i.e. diameter) as compared with the tree utilized for Test Series 1.

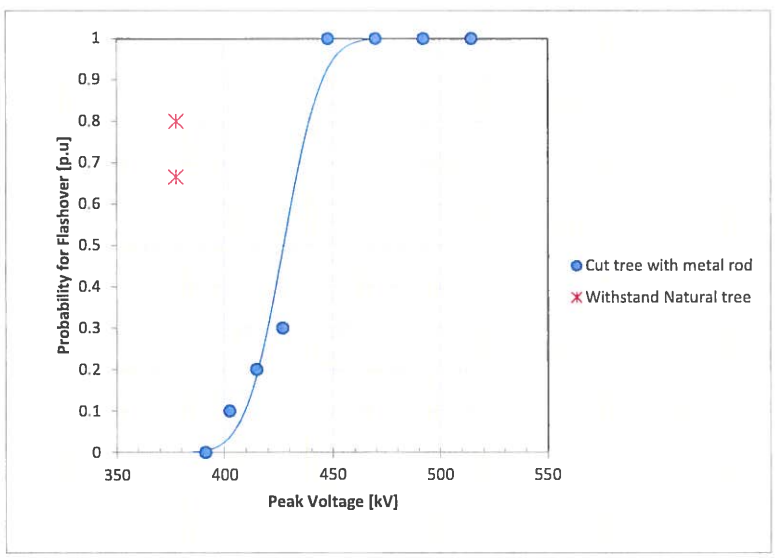
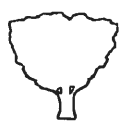


Figure 5-7
Probability for flashover for "Natural Tree" (Test 3.2) and "Cut Tree with metal rod" (Test 2.1) for the Vase Tree at 230kV Vertical configuration.

Summary of the Results

The outcome of the withstand tests performed on natural trees is summarized in Table 5-4.

Table 5-4
Summary of the outcome of the switching impulse voltage withstand testing on natural vegetation.

Nominal Voltage				**230 kV (U_m: 242 kV)**
Bundle (# of conductors per phase)				1
Sub-conductor spacing [inch]				n/a
Bundle height above ground [Feet]				20.3
Conductor size (Outer diameter) [inch]				1.25
Bundle shape				●
Gap [feet]				3.08 (37")
Gap [m]				0.94
#	**Orientation**	**Shape**		**Test Outcome (applied voltage, kV)**
3.1	Horizontal / Blow together	Columnar		Pass (389)
3.2	Vertical / Grow-in	Vase		Fail (378)

Note: All applied voltage levels refer to standard atmospheric conditions as per IEEE std 4.

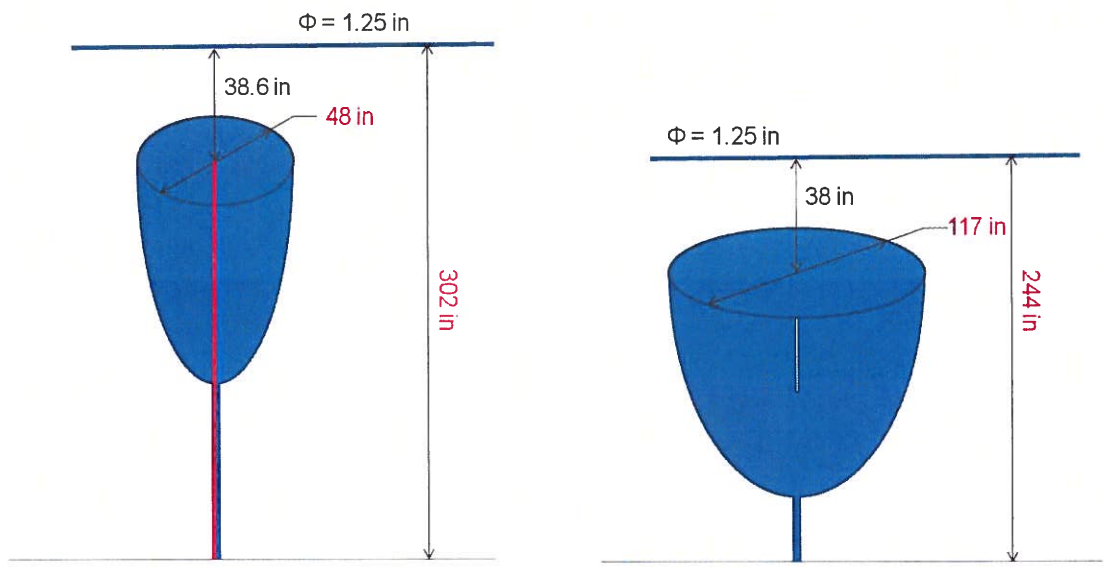
Additional Testing: Test 3.2: Vase, 230 kV, Vertical Configuration

Objective of Testing

The lower than expected withstand voltage observed during withstand test 3.2 prompted a number of additional tests to address the following concerns:

- Determine if the difference in test location resulted in the lower withstand strength on the natural tree compared to the cut trees with grounded center metal rod. The natural trees, utilized for the withstand tests, were planted in the southern region of the Lenox laboratory, across the river from the location of the tests on the cut trees with grounded metal rod and those cut trees with wooden dowel on top of the grounded metal rod.
- Determine if the size (i.e. diameter) of the tree utilized for the test impacts the flashover strength of the gap. It was noted that the vase shaped natural tree had a significantly larger diameter, at the flat top, than the cut trees used for the tests on with grounded metal rod. The dimensions of the cut and natural trees utilized for the tests are presented in Figure 5-8.
- Determine if the height of the conductor above ground impacted the flashover strength of the gap. For Test series 1 and 2 (Cut trees with center rod and with dowel) the setup was designed to enable full control of all the test dimensions, including the specified height of the bundle as well as the gap size to the vegetation. This was not possible for the withstand tests

(Test Series 3), because the natural tree could, for obvious reasons, not be raised or lowered. Consequently the height of the conductor above ground had to reduced, in some cases to below the NESC ground clearance limit, to achieve the required gap setting. The heights of the conductors for Test Series 1 and 3 are presented in Figure 5-8.



Cut trees with grounded metal rod	Natural vegetation

Figure 5-8
Approximate dimensions of the Cut Tree with Metal Rod (Test series 1) and Natural Tree (Test series 3)

Tests performed

The additional tests were performed on the Natural, Vase-shaped tree, and a gap setting related to a Nominal System Voltage of 230 kV. For these tests the tree subjected to the withstand testing was cut and moved to the test location close to the impulse generator which was also used for the Series 1 and 2 tests. A total of four tests were performed on this "*natural tree from across the river*" such that it could be compared to the original Vertical Vase cut tree with metal rod 230 kV test (Test 1.1 Test #2):

- Test 3.x.a: Flashover testing of tree without any metal rods, or dowels.
  - The results of this test was compared with the withstand test result (Test 3.2) to check if test location has an effect on the determined flashover strength.
- Test 3.x.b: Add Metal rod to the setup tested in Test 3.x.a so that it resembles the test setup used for Test Series 1, but with the same conductor height as was used for the withstand test.
  - The results of this test were compared to that of Test 3.x.a to check conservatism of the results when testing is performed on a tree in combination with a metal rod.
  - These results were also compared with Test 1.1 (230 kV, Vase) from series 1 to determine if the change in tress size and the height of the conductor impacted the flashover strength.

- Test 3.x.c: The tree, which had a diameter at the flat top of about 117" was trimmed down to have a diameter of 48" which is similar to the tree used for the Test 1.1 (230 kV, Vase shape) from the series 1. The modified tree was tested without any metal rods, or dowels.
  - The results of this test were compared with those of Test 3.x.a to determine influence of tree size.
- Test 3.x.d. Add Metal rod to the setup tested in Test 3.x.c so that it resembles the test setup used for Test Series 1, but with the same conductor height as was used for the withstand test.
  - The results of this test were compared to that of Test 3.x.c to check conservatism of the results when testing is performed on the tree in combination with the metal rod.
  - These results were also compared with Test 1.1 (Vase) from series 1 to determine if the change the height of the conductor impacted the flashover strength.

For these tests the critical flashover voltage (that is CFO or U_{50}) has been determined with the "up-down method" (UDM) or Multiple-Level-Method (MLM) as appropriate.

Results

The results of the tests are summarized in Table 5-5 and in Figure 5-9.

Table 5-5
Summary of the results of additional tests performed on the Vase, 230 kV, Vertical configuration.

				Nominal Voltage	**230 kV (U_m: 242 kV)**
				Bundle (# of conductors per phase)	1
				Sub-conductor spacing [inch]	n/a
				Bundle height above ground [Feet]	25.2
				Conductor size (Outer diameter) [inch]	1.25
				Bundle shape	●
				Gap [feet]	3.08 (37")*
				Gap [m]	0.94
#	**Orientation**	**Shape**		**Description**	**Determined Gap Factors (CFO kV)**
3.2	Vertical / Grow-in	Vase (117" Diameter)		Withstand test Natural in situ	> 1.06 (>378) [from Chapter 5]
3.x.a				Natural - cut	1.07 (382)
3.x.b				With metal rod, Cut	1.13 (405)
3.x.a(2)				Natural – cut (repeat)	1.11 (397)
1.1		Vase (48" Diameter)		Original test With metal rod – Cut	1.15 (427) [from Chapter 3]
3.x.c				Natural - cut	1.18 (421)
3.x.d				With metal rod, Cut	1.20 (429)

Note: The height of the conductor was increased slightly for the tests with the metal rod to compensate for the distance that the rod is sticking out above the vegetation.

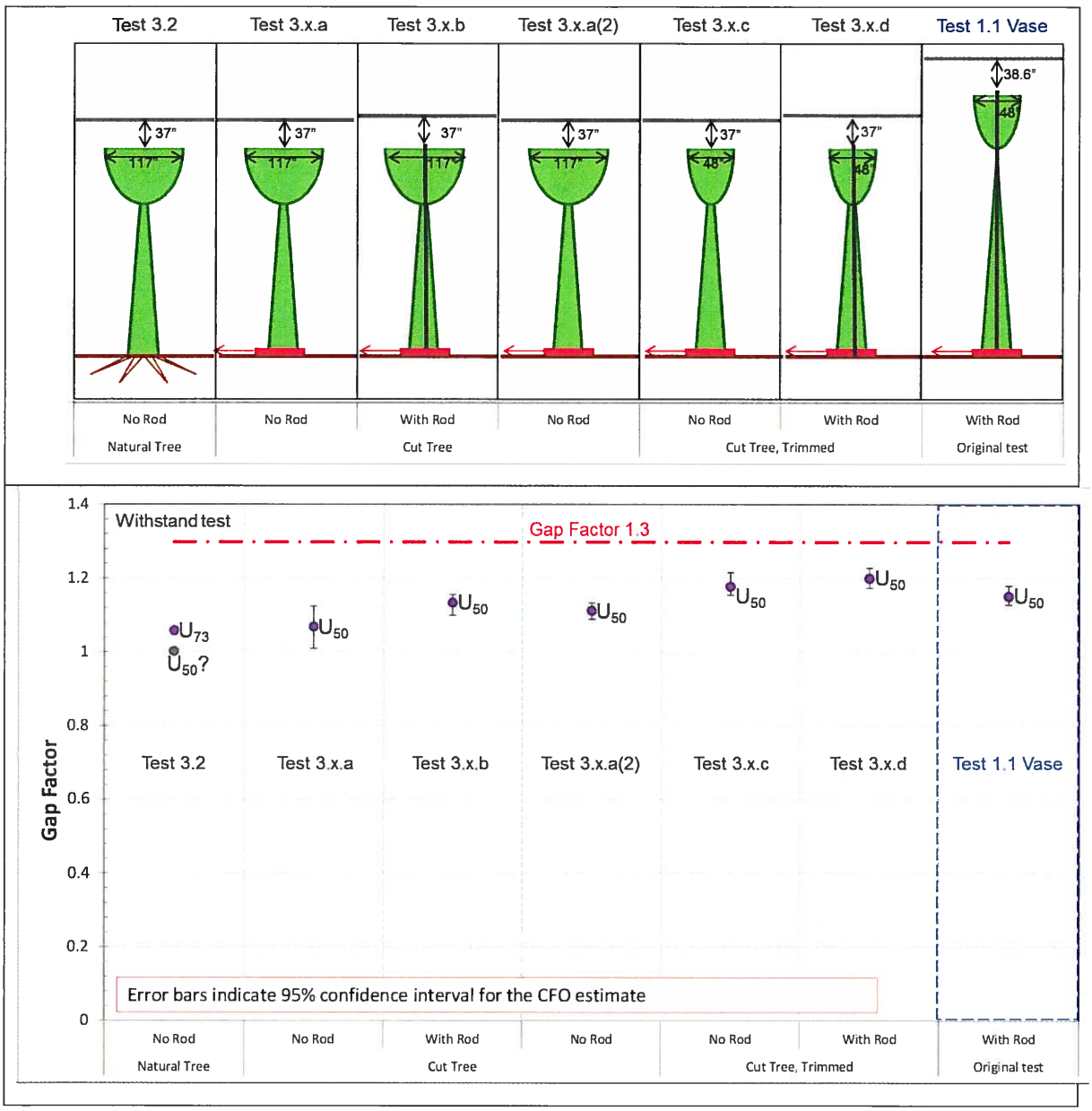


Figure 5-9
Graphical representation of the results of additional tests performed on the Vase, 230 kV, Vertical configuration.

Analysis and Discussion

Location of the Test Object

The location of the test object does not seem to have a marked influence on the strength of the gap, although the tests performed on the cut trees at the generator (3.x.a) did result a higher flashover voltage than the withstand test (3.2). The observed increase falls however within the tolerances expected for this kind of testing.

Furthermore it is not considered likely that the greater distance to the test location of the natural trees to that of the cut trees had a significant impact. This is because the steepness of the applied switching surges is low enough that the voltage at the test location of the natural trees is practically the same as at the generator. This becomes clear when one considered that the time to peak of the switching surge is 100 micro-seconds while the travel time of the surge from the generator to the test location is only in the order of 5 micro-seconds.

Test location has therefore only a limited influence on gap factor.

Size of Tested Tree

Each freshly cut tree would experience leaf wilting after a day or two and would need to be discarded. While care was taken to match the shape of the trees from Test 1-Test 2- Test 3, the diameter of the natural tree was not altered before the test. Consequently the natural tree used for withstand (Test 3.2) had a much wider tree branch width than the Test 1.1 (Figure 5-8).

The additional tests (Test Series 3.x) showed that the diameter of the tree crown impacted the strength of the conductor to tree gap. The flashover strength to the trimmed down (smaller diameter) tree was found to be higher than that of the unaltered (larger diameter) tree. In Figure 5-9 it can be seen that the results of additional tests 3.x.c and 3.x.d on the trimmed down tree agreed well with the original test (Test 1.1 vase) with a gap factor of approximately 1.2 whereas the tests on the wider diameter tree resulted in a gap factor of about 1.1.

Vegetation diameter therefore has a significant impact on gap factor.

Height of Conductor

All the additional tests (test series 3.x) were performed for a conductor height of 244"which is the same as was used for the withstand test. The Test Series 1 tests on the same configuration were performed for a conductor height of 302" which is significantly higher. A comparison of additional tests 3.x.d, 3.x.c with the results from Test 1.1, vase (See Figure 5-9) shows similar results that falls within the tolerances expected for this kind of testing.

The height of the conductor bundle above the ground plane has therefore little influence on gap factor.

Other Observations

Other observations made on the results of the additional tests presented in Figure 5-9 are:

- The addition of the metal rod to the cut tree did not result in a significant change in the observed CFO values. Compare Test 3.x.a (both tests) with 3.x.b and Test 3.x.c with 3.x.d.

The repeatability of the flashover tests on natural trees seems to be reasonable based on a comparison of the results. This assessment is based on a comparison of the results from Test 3.x.a with that of Test 3.x.a(2) and Test 3.x.d with Test 1.1 vase. The test data seems to indicate however that there is a slight increase in flashover strength over time if the same tree is utilized. This is probably due to the drying out and wilting of the cut trees over time.

6
CONCLUSIONS

The aim with this project was to conduct testing to develop empirical data regarding the flashover distances between conductors and trees, and to use an approach based on statistical analysis to evaluate the test results and provide empirical evidence to support an appropriate gap factor to be applied in calculating minimum clearance distances using the Gallet equation.

A simple synopsis of the three test types and the results is provided below. Additional tests were conceived and executed to improve understanding of the results.

Impulse Flashover Strength to the Grounded Metal Rod

The purpose of this test was to provide repeatable, statistical, conservative characterization of the Gap Factor for a number of tree shapes, conductor positions, configurations, and voltages. Table 3-4 shows the full series of tests to the grounded metal rod. The gap configurations that resulted in the lowest gap factors were:

Test 1.1: Vase, 230 kV, Vertical configuration:

Gap factor (k_g) = 1.15

Test 1.2: Columnar, 230 kV, Horizontal configuration:

Gap factor (k_g) = 1.02

Twelve of the twenty tests yielded gap factors lower than 1.3, which is the gap factor that NERC submitted and FERC questioned.

Impulse Flashover Strength to the Wooden Dowel

The intent of the dowel test was to demonstrate that the switching impulse strength of a gap comprising the energized conductor and a "wooden branch end electrode" is greater than that of an identical gap comprising the energized conductor and a "metal end electrode." This test was only intended to qualitatively illustrate that the fully conductive tree tests (Test Series 1) were conservative. No quantitative comparisons were intended to be made between these tests. Only the gap configuration which resulted in the lowest gap factor in Test Series 1 was considered. The result of this test is:

Test 2.0: Columnar, 230 kV, Horizontal configuration:

Gap factor (k_g) = 1.22

The results show that the configuration with the wooden dowel resulted in a higher gap factor (1.22) than that obtained for the test with the central metal rod (1.02). Also note that the gap factor for the wooden dowel was 1.22, which is still lower than the 1.3 in the proposed standard.

Withstand Strength to Natural Vegetation

The objective of the withstand tests on natural vegetation was to validate that the MVCD calculation method is applicable to the two worst cases. Voltage withstand testing was performed using a critical switching impulse waveform on natural trees. The test was performed for the voltage class, and off-set direction that resulted in the two lowest gap factors in the metal rod Test Series 1:

Test 3.1: Columnar, 230 kV, Horizontal configuration:

Withstand Test result: Passed

Test 3.2: Vase, 230 kV, Vertical configuration:

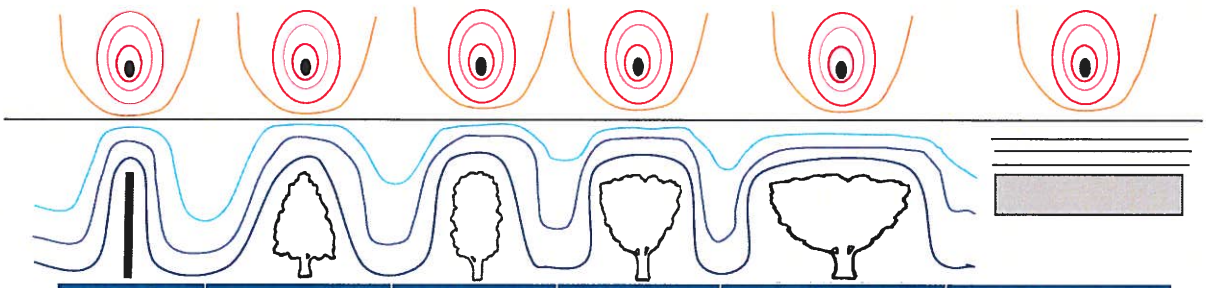
Withstand Test result: Failed

Based on these results it is concluded that the calculation approach using a gap factor of 1.3 is not valid.

Significant Learnings

Based on the results of all tests performed a number of general learnings have been identified:

1. Although, the use of the gap factor is well established for the initial dimensioning of the insulation design of transmission line structures, its applicability to vegetation clearances seems to be questionable. For transmission lines the gap configuration is well defined and there is a large body of empirical evidence to support the selection of appropriate gap factors. For vegetation clearances, however, there is a greater variability in the tree shapes and sized which significantly impact the value of the gap factor, even for the same conductor configuration and gap size. These factors amplify the inherent inaccuracy of this approach.
2. As anticipated, for the same configurations, the test results for the tree shapes employing a metal rod was more conservative (lower breakdown strength) than the same configuration with a wooden dowel, which in the same fashion was more conservative (lower breakdown strength) than the same configuration for the natural trees.
3. The height of the electrode above the ground plane has little influence of gap factor.
4. For vertical tests it was shown that a larger flat-top diameter (i.e. tree size) is associated with a weaker breakdown voltage. Therefore, vegetation diameter has significant impact on gap factor. The most conservative tree shape / conductor configuration appears to be vertical offset above a vase tree (flat-top).
5. Figure 6-1 illustrates the impact of vegetation diameter on the electric field distribution and the measured gap factors. The left hand figure represents a conductor –rod gap factor (designated as a gap factor of 1.4 -1.6). The configuration on the far right represents a conductor to plane (with gap factor of 1.1). The middle configurations more closely represent a conductor-lateral structure (with Gap factor of 1.25-1.4).
6. It can be concluded that pointy-topped tree under a line approximates a conductor - rod (Gap Factor 1.25-1.4). A flat topped tree under a line in which the diameter is large compared to the conductor-tree gap, approximates a conductor plane (Gap Factor = 1.1).



Rod	Pyramidal	Columnar	Vase (48”)	Vase (117”)	Plane
1.4 - 1.6	1.44	1.15	1.15	1.07≈1.1	1.1

Large trees (compared to gap size) approaches conductor plane configuration

Figure 6-1
Influence of Tree Top Diameter on Gap Factor

7
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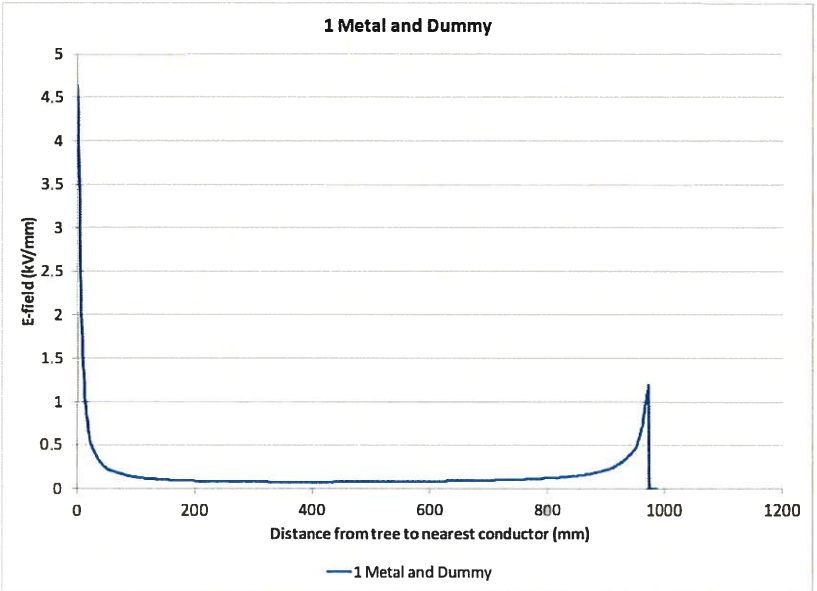
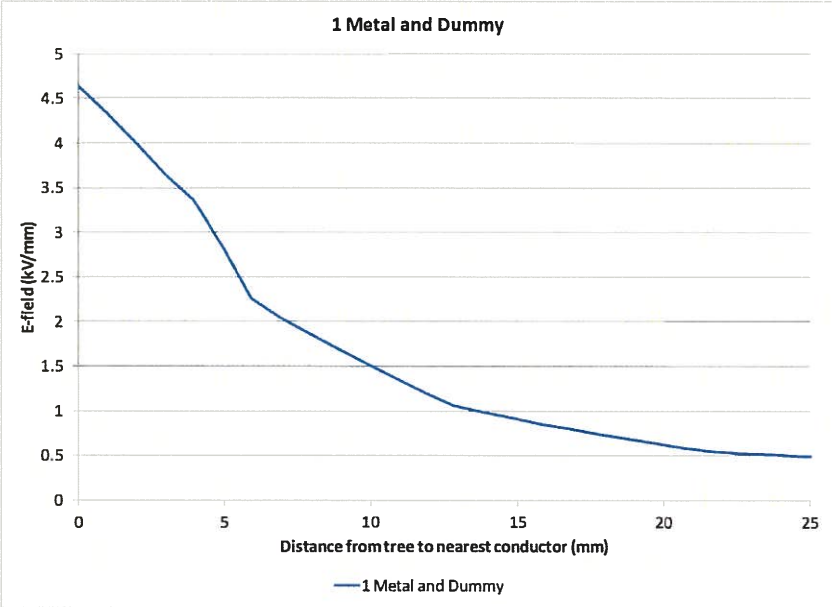
A
APPENDIX A: E-FIELD MODELING

Vegetation Management: *E-field Modeling*
1. Metal Tree



1. Metal Tree



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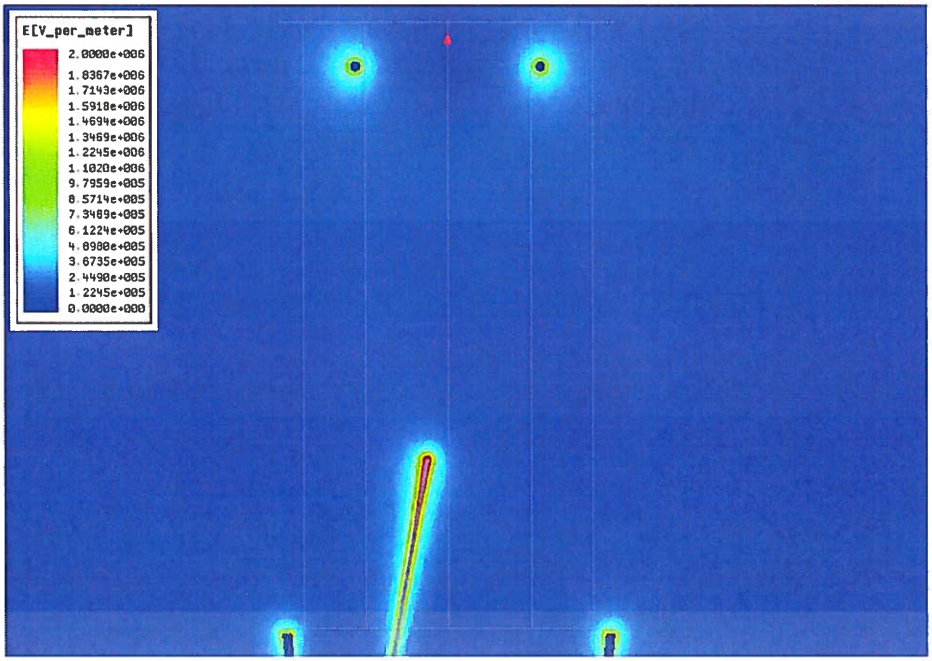

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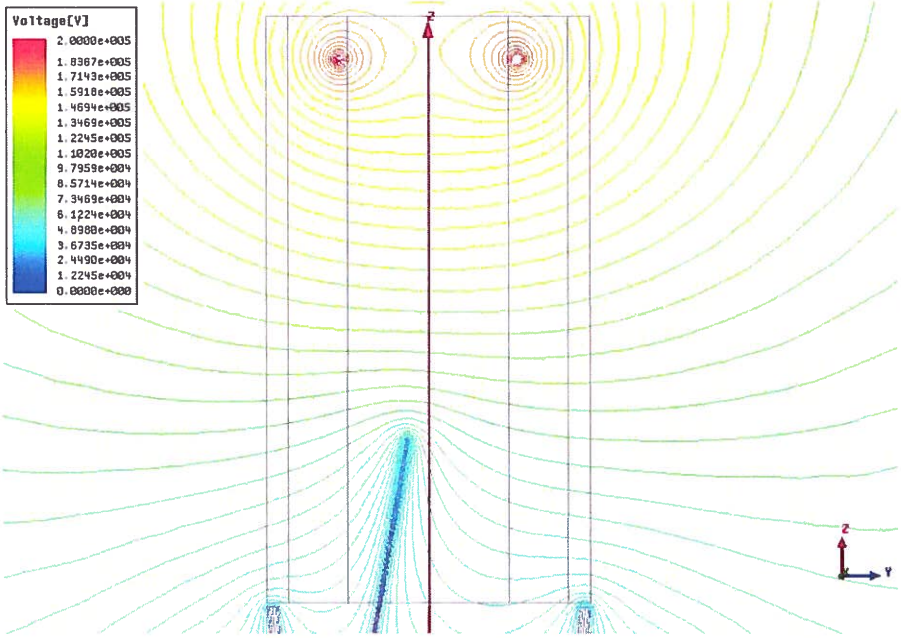
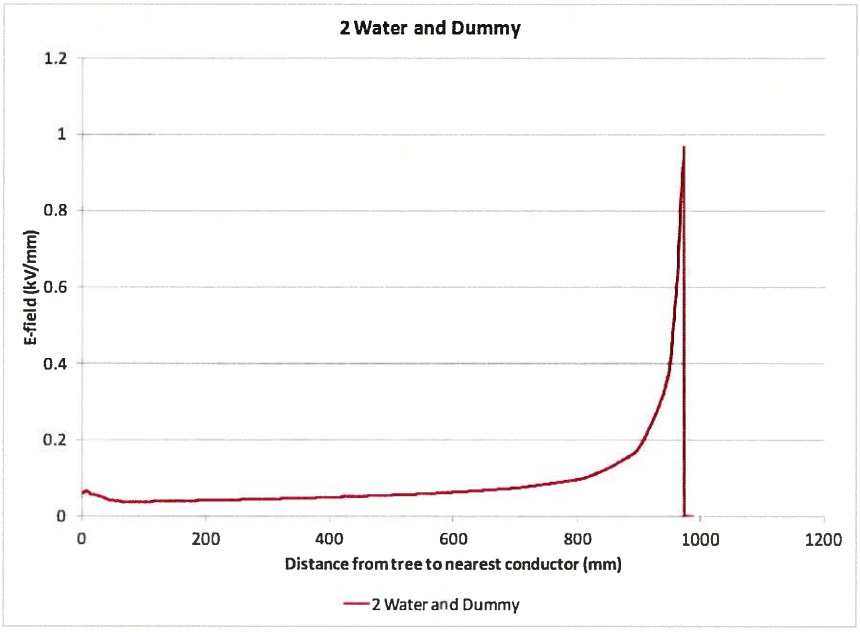


2. Water Tree



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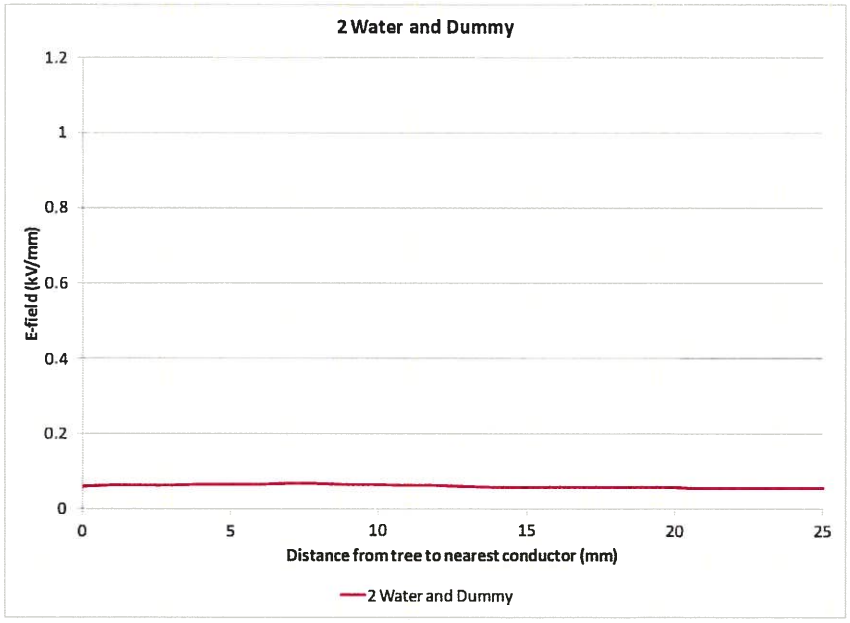

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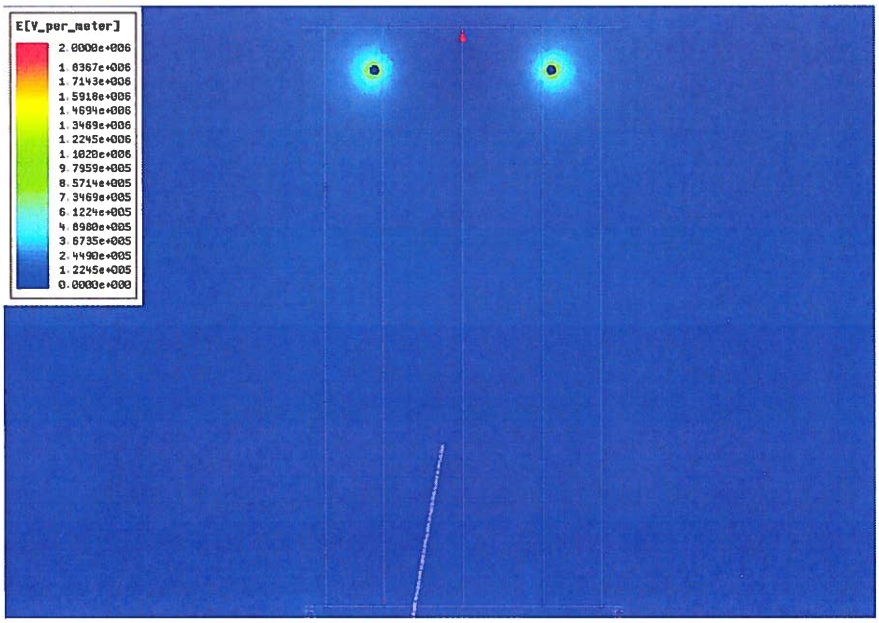

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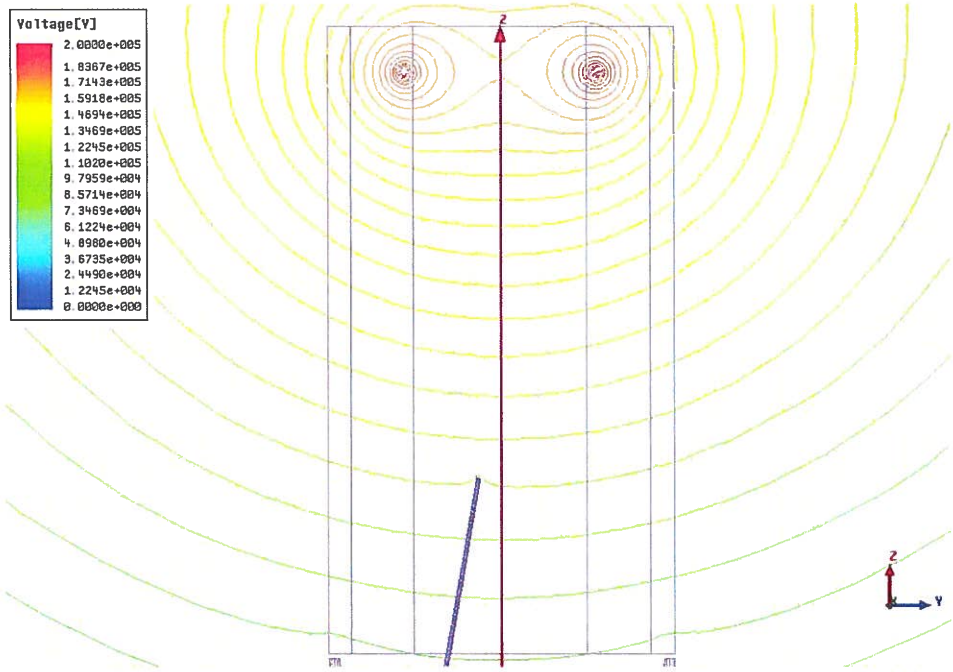
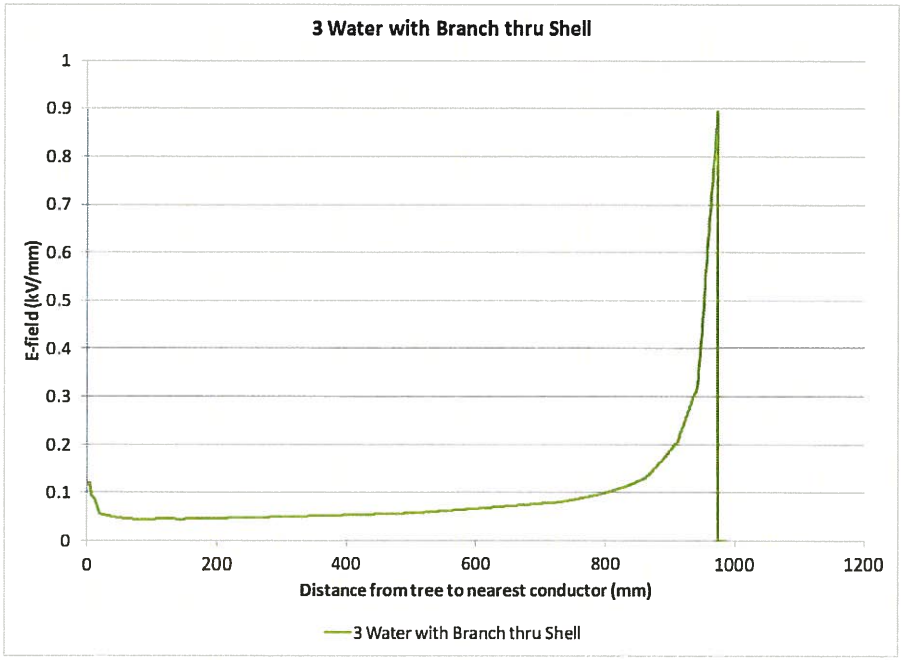


3. Water Tree with Hollow Water Shell



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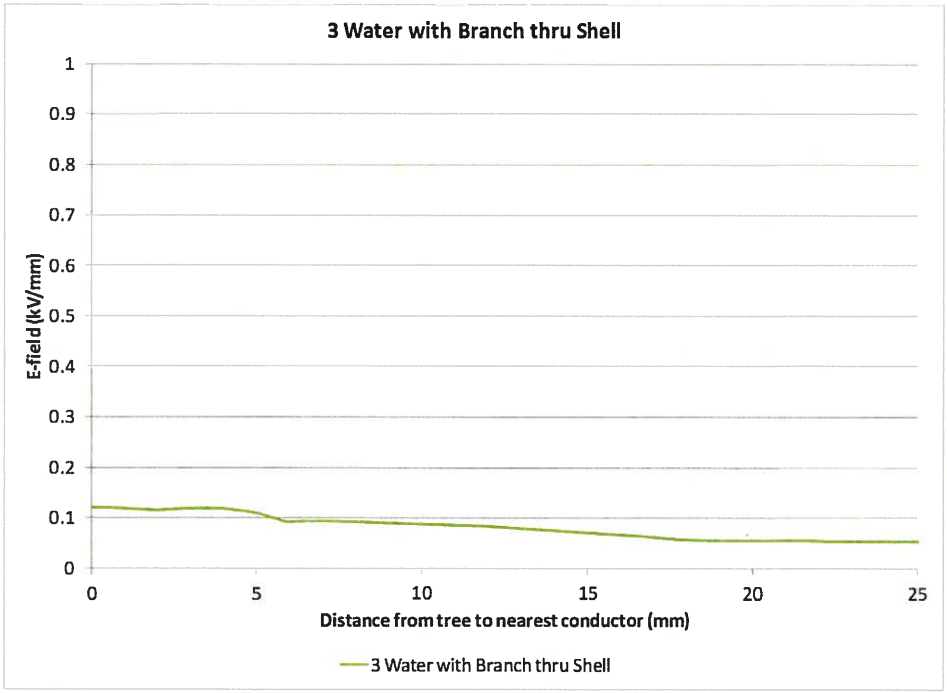

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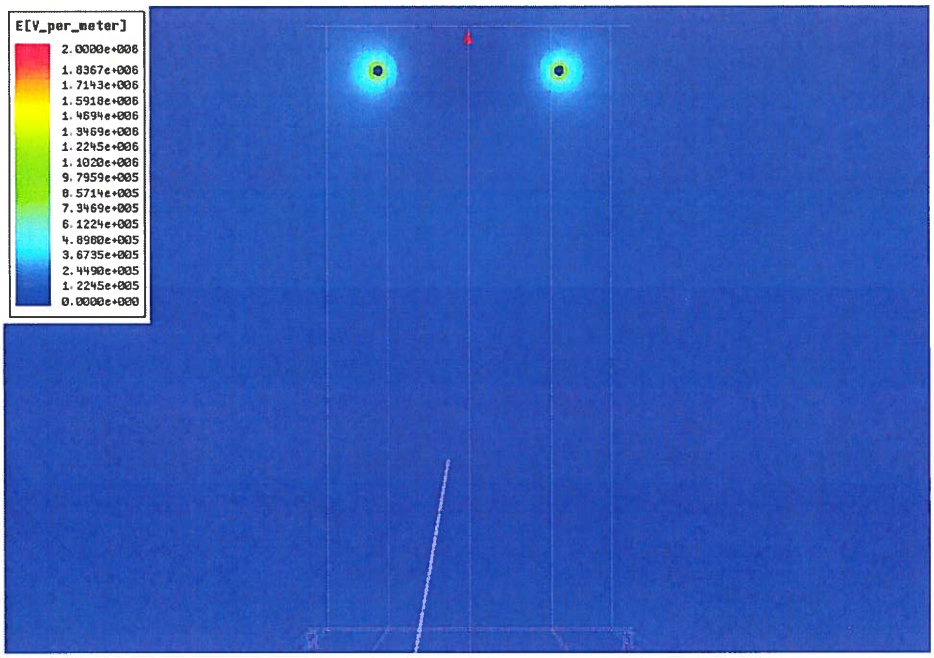

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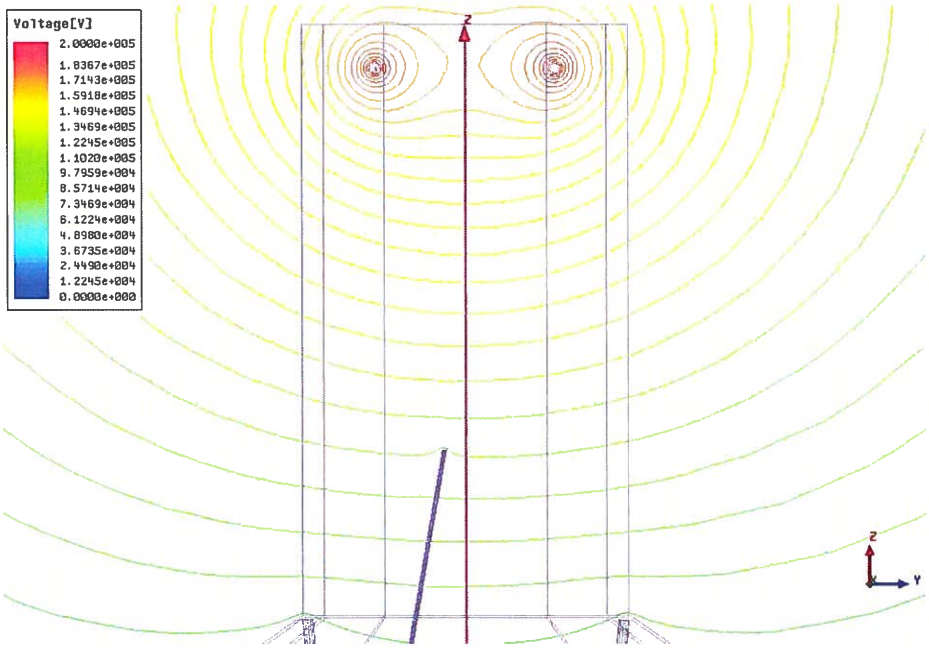

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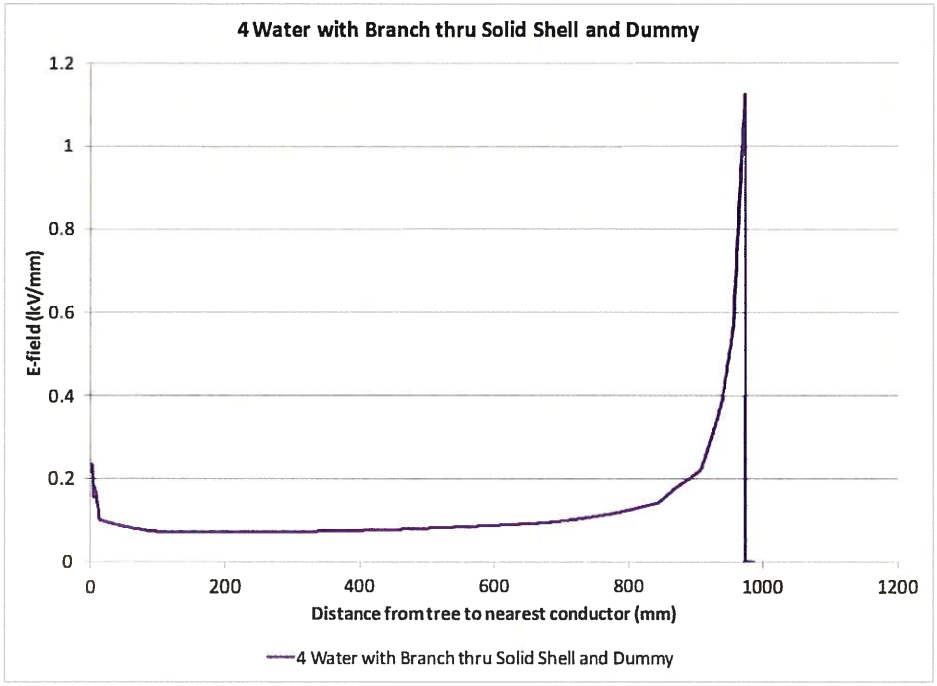

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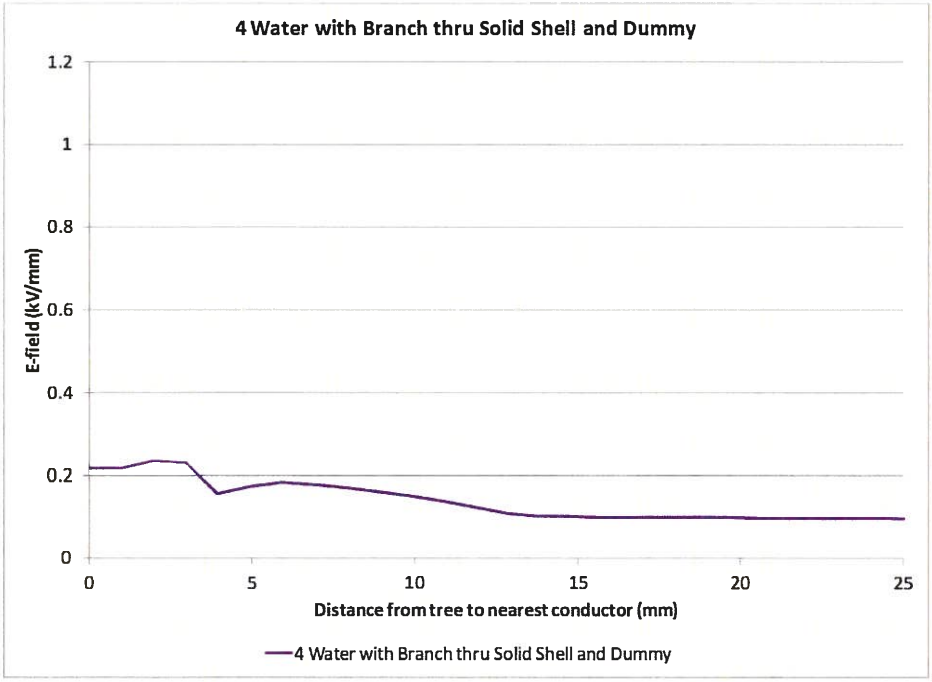

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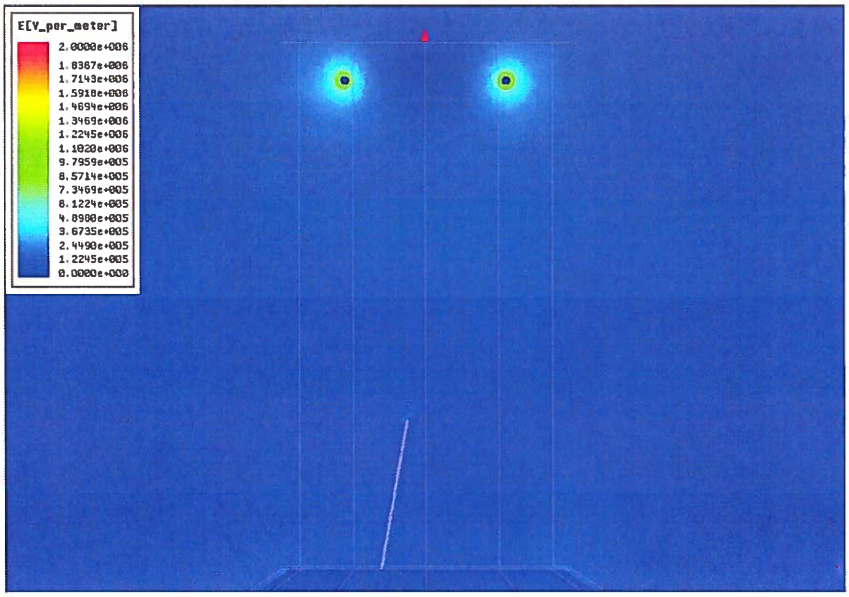

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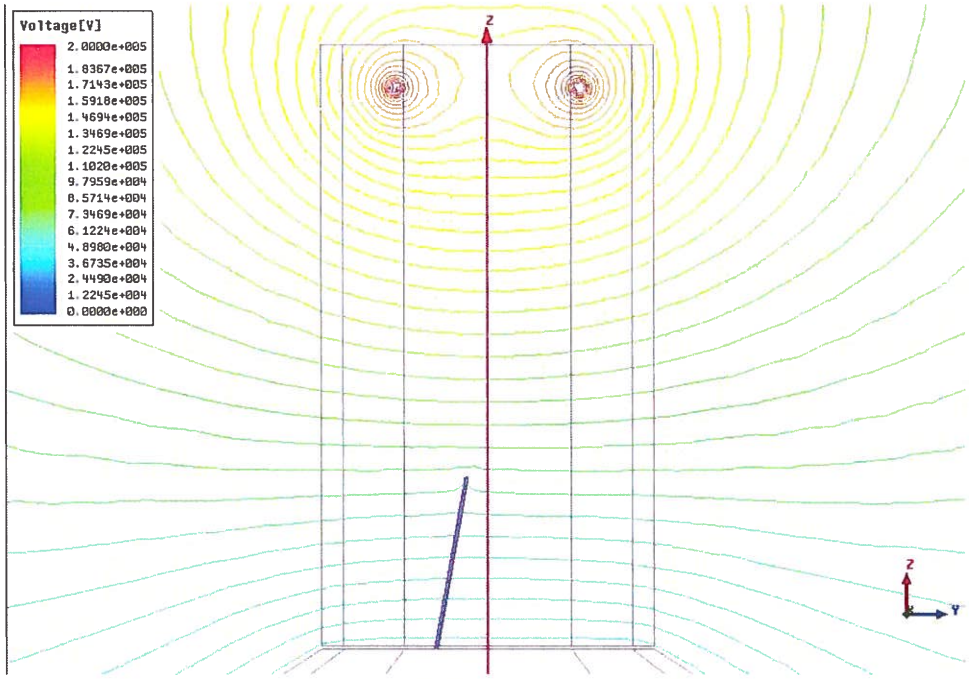
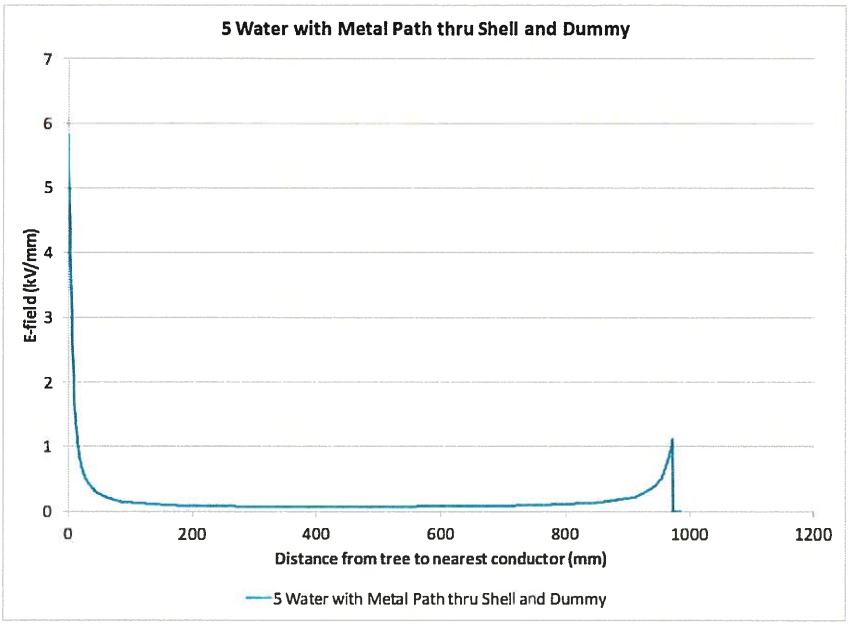


5. Water Tree, Hollow Water Shell, Metal Rod



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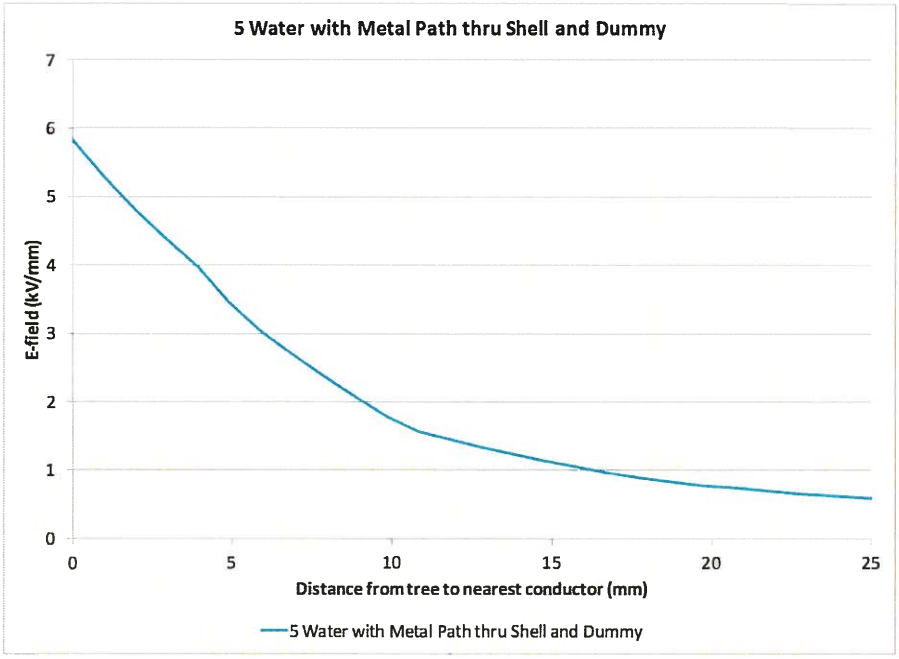

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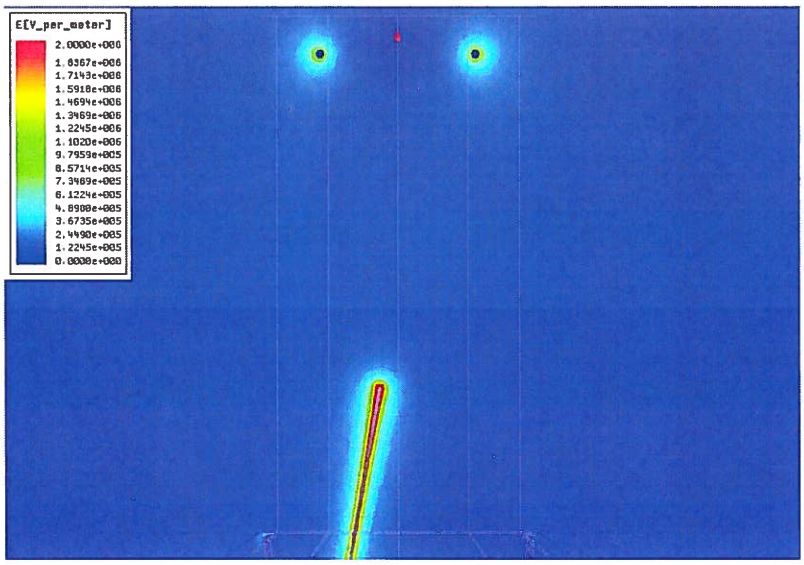

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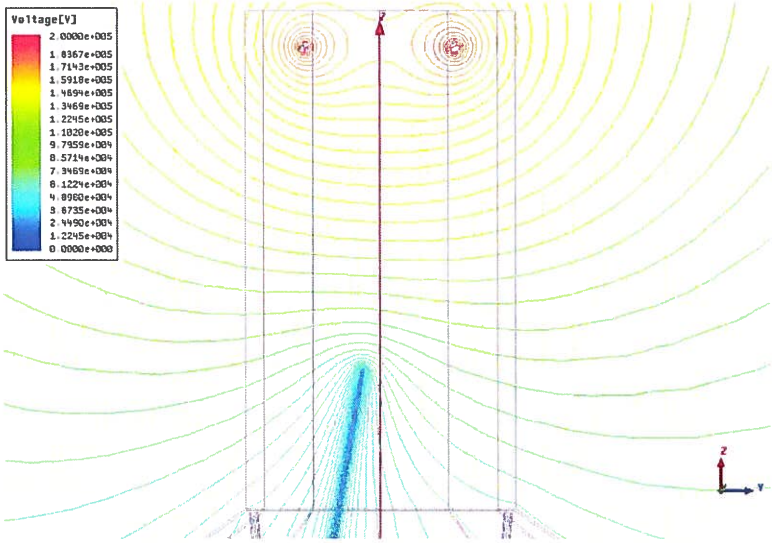

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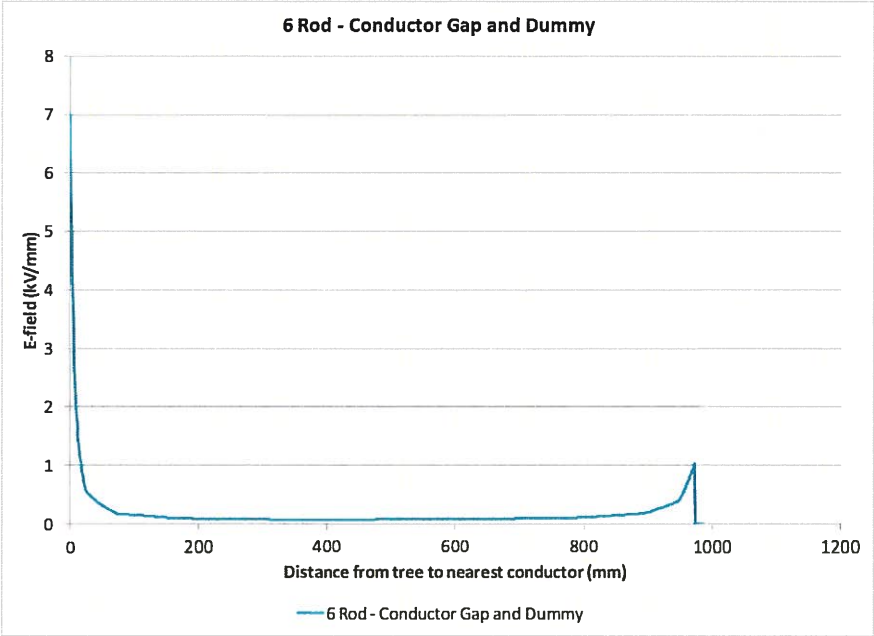

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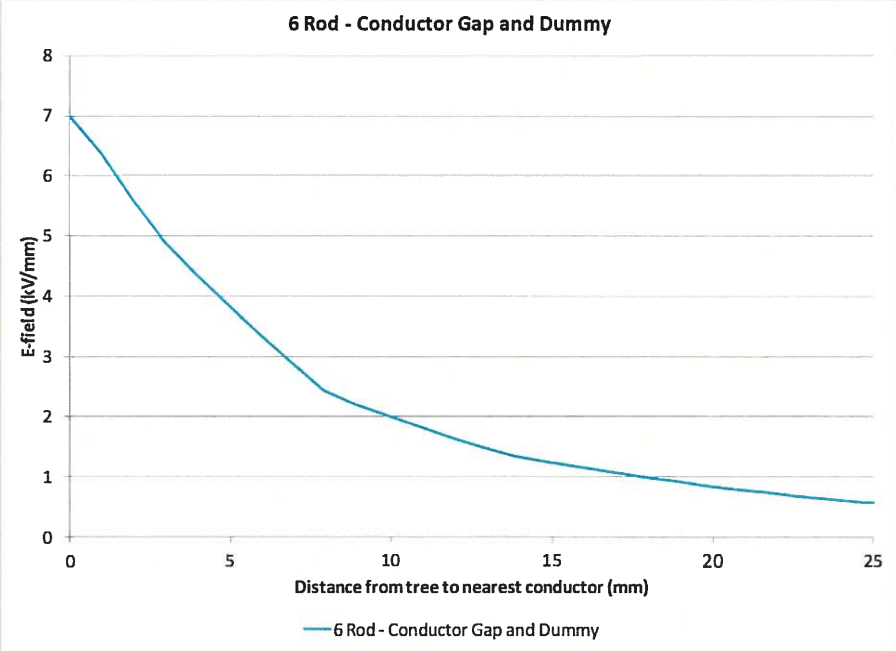

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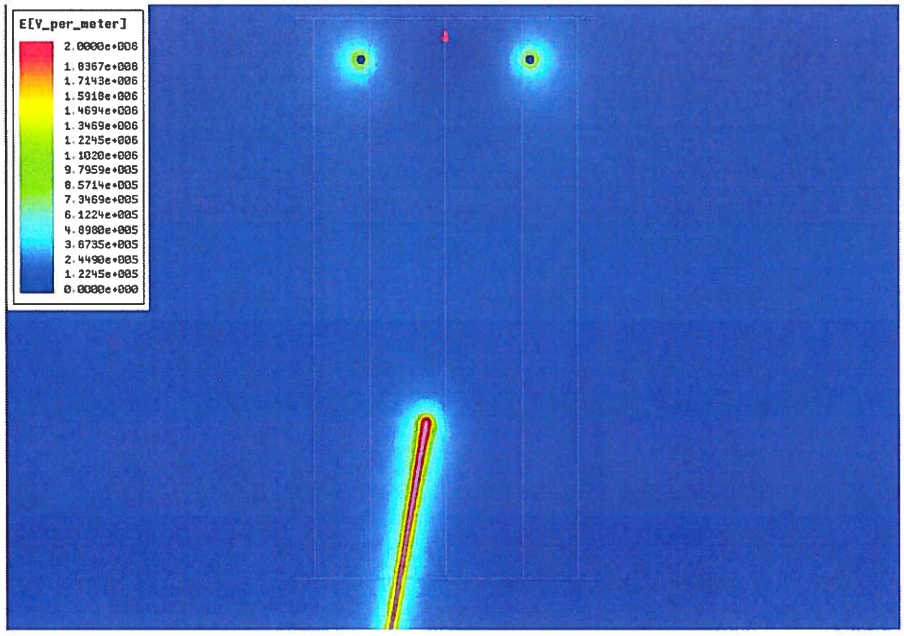

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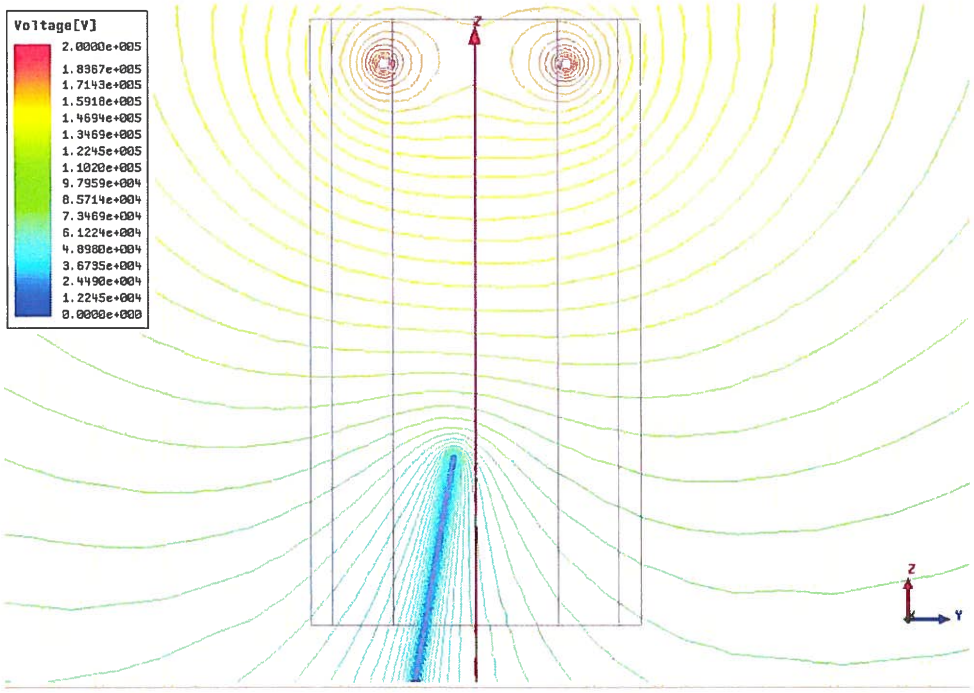
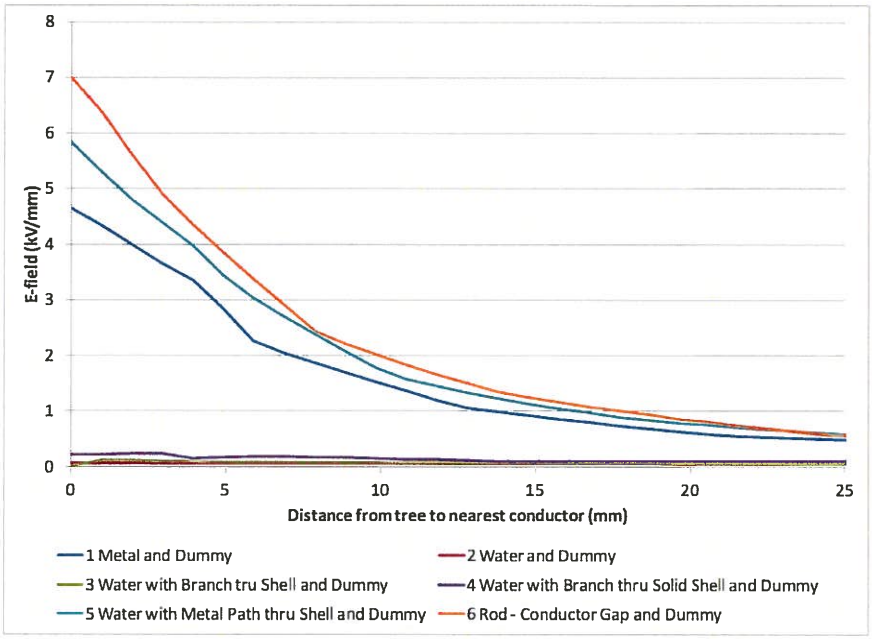
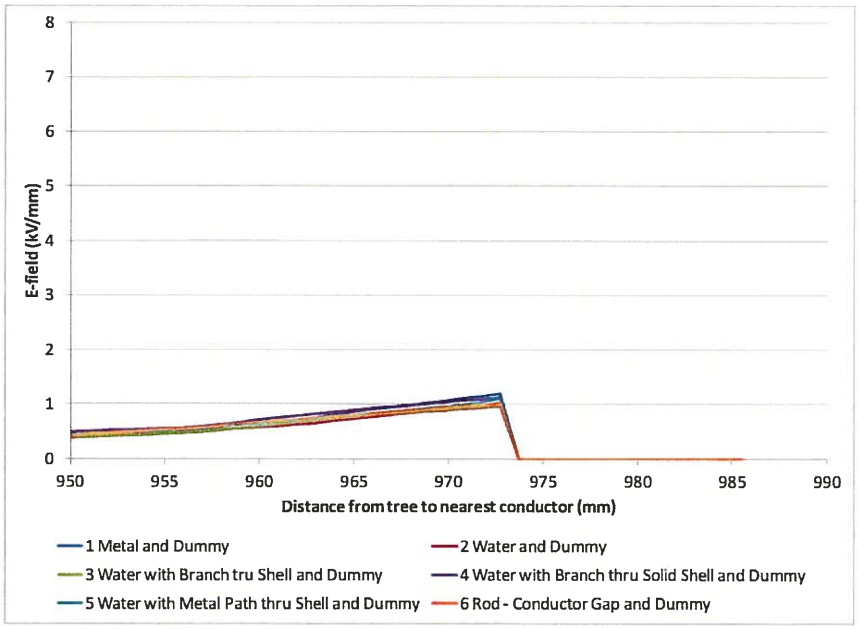


Summary



Summary



B

APPENDIX B: DEFINITION OF REPLACEABLE WOODEN SECTIONS

A suitable source of the dowels were large, eastern cottonwood trees which were identified on the Lenox Laboratory property. The logs were harvested within two days of testing and transported to a local sawmill. One inch thick boards were sawn at the mill and transported back to the Lenox Laboratory. The boards were then ripped into one inch square cross-section dowels on a table saw at the laboratory the day of testing.

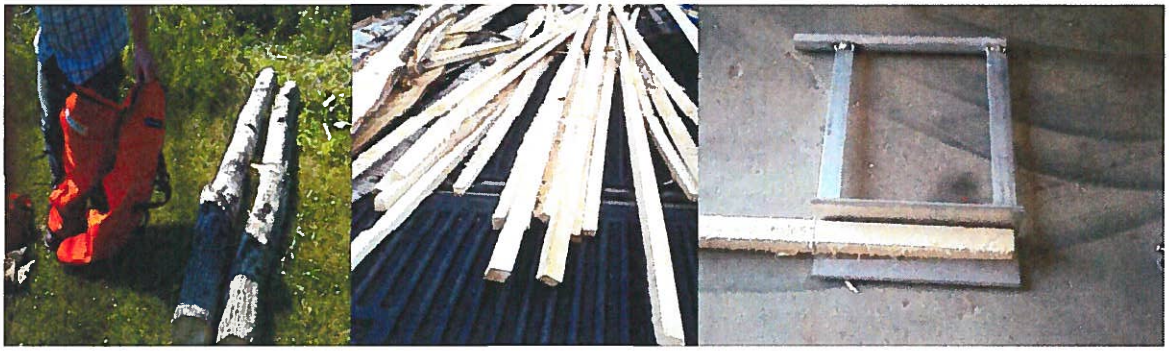


Figure B-1
Cottonwood Logs, Dowels, and Off-Set Mounting Bracket

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Exhibit E-2 Final Report July 2015 as Revised February 2016 Supplemental Testing to Confirm or Refine Gap Factor Utilized in Calculation of Minimum Vegetation Clearance Distances (MVCD)

ELECTRIC POWER RESEARCH INSTITUTE

Supplemental Testing to Confirm or Refine Gap Factor Utilized in Calculation of Minimum Vegetation Clearance Distances (MVCD)

Tests: Results and Analysis Including a Recalculation of MVCD for 1.0 Gap Factor

2015 TECHNICAL REPORT

Supplemental Testing to Confirm or Refine Gap Factor Utilized in Calculation of Minimum Vegetation Clearance Distances (MVCD)

Tests: Results and Analysis Including a Recalculation of MVCD for 1.0 Gap Factor

EPRI Project Manager
R. Lordan

ELECTRIC POWER RESEARCH INSTITUTE

3420 Hillview Avenue
Palo Alto, CA 94304-1338
USA

PO Box 10412
Palo Alto, CA 94303-0813
USA

800.313.3774
650.855.2121

askepri@epri.com

www.epri.com

3002006527
Final Report, July 2015
Revised February 2016

THE FOLLOWING ORGANIZATIONS PREPARED THIS REPORT:

Engelbrecht Consulting B.V.

Electric Power Research Institute (EPRI)

NOTE

For further information about EPRI, call the EPRI Customer Assistance Center at 800.313.3774 or e-mail askepri@epri.com.

Acknowledgments

The following organizations prepared this report:

Engelbrecht Consulting B.V.
Catharinadaal 84
Ede, 6715 KD
The Netherlands

Principal Investigator
C. Engelbrecht

Electric Power Research Institute
3420 Hillview Ave
Palo Alto, CA

Principal Investigators
R. Lordan
A. Phillips

Electric Power Research Institute
High Voltage Laboratory
115 East New Lenox Road
Lenox, MA 01240

Principal Investigator
D. Childs

This report describes research sponsored by EPRI.

This publication is a corporate document that should be cited in the literature in the following manner:

Supplemental Testing to Confirm or Refine Gap Factor Utilized in Calculation of Minimum Vegetation Clearance Distances (MVCD): Tests: Results and Analysis Including a Recalculation of MVCD for 1.0 Gap Factor Using Specified Rounding Process.
EPRI, Palo Alto, CA: 2015.
3002006527.

Product Description

Testing was performed to determine the switching impulse strength of the air gap between a conductor and natural trees to validate revision of the gap factor to 1.0 in order to determine the minimum vegetation clearance distance (MVCD) in North American Electric Reliability Corporation (NERC) Standard FAC 003-2. These tests complement those reported in EPRI's *Testing to Confirm or Refine Gap Factor Utilized in Calculation of Minimum Vegetation Clearance Distances (MVCD): Test Results and Analysis* (3002006078, April 2015). The present report provides utilities, the North American Electric Reliability Corporation (NERC), and the Federal Energy Regulatory Commission (FERC) with the information necessary to validate the proposed revision of the gap factor used for MVCD calculations.

Background

In response to FERC Order No. 693, NERC submitted the reliability standard FAC-003-2, *Transmission Vegetation Management*. In the submittal, NERC proposed a methodology for calculating the MVCD based on the Gallet equation and the use of a gap factor of 1.3 pursuant to FAC-003-2.

On March 21, 2013, FERC issued its Final Rule of the *Revisions to Reliability Standard for Transmission Vegetation Management*. In this document, the NERC Reliability Standard FAC-003-2 was approved and NERC was directed "to conduct or contract testing to develop empirical data regarding the flashover distances between conductors and vegetation," and to use an approach based on "statistical analysis [that] would then evaluate the test results and provide empirical evidence to support an appropriate gap factor to be applied in calculating minimum clearance distances using the Gallet equation."

A research project was subsequently initiated to provide empirical evidence to support the selection of an appropriate gap factor that would be applied in calculating the MVCD using the Gallet equation. The results showed, however, that the values based on a gap factor of 1.3 are not conservative. Based on this finding, NERC issued an Industry Advisory (Alert ID: A-2015-05-14-01), which highlighted the anticipated adjustments utilizing a gap factor of 1.0 for the MVCD specified in NERC Reliability Standard FAC-003-3.

Objectives

To confirm, or if necessary, advise NERC of the adequacy of the revised gap factor (k_g) of 1.0 as a basis for the MVCD calculation using the method documented in NERC Reliability Standard FAC-003-3.

Approach

Switching impulse tests were designed and executed at EPRI's High-Voltage Laboratory in Lenox, Massachusetts. The goal of this testing was to determine the critical flashover voltage (CFO, U_{50}) for the revised MVCD applicable to a 230-kV system and a natural, vase-shaped tree for a tree-to-conductor distance calculated using a gap factor of 1.0. The gap factor (k_g) is calculated and compared against the 1.0 value proposed by FERC and NERC. Testing involved a range of tree canopy diameters in order to confirm that the choice of gap factor is acceptable for all tree diameters.

Results

This report provides a detailed description of the switching impulse tests performed on natural trees. Included is a description of the test setups, the procedure used, and test results. Based on the results of testing, the following conclusions may be drawn:

- Within the confines of the testing performed (resulting in a large confidence region), the gap factor of a conductor over a large flat top tree approaches that of a conductor-plane gap, which is $k_g = 1.1$.
- The results confirm the adequacy of using a gap factor (k_g) of 1.0 as a conservative basis for the calculation of MVCD according to the method documented in NERC Reliability Standard FAC-003-3.

The report also includes an Appendix with examples showing the implementation of the calculation methodology proposed in the "Transmission Vegetation Management NERC Standard FAC-003-2 Technical Reference" and the resulting MVCD tables.

Applications, Value, and Use

This research is performed to provide an empirical basis to verify the MVCD values in the NERC Reliability Standard FAC-003-3. It is expected that these results will be incorporated in the NERC writing process as part of a review of the present standard.

Keywords

Minimum vegetation clearance distance (MVCD)
Impulse testing
Flashover distance
Trees
Gap factor
Critical flashover voltage

Abstract

NERC proposed a methodology for calculating the minimum vegetation clearance distances (MVCD) based on the Gallet Equation and the use of a gap factor. EPRI's approach was to validate the gap factor used in the NERC standard using empirical evidence through switching impulse testing between trees and conductor bundles. The project pursued a statistically valid scientific approach.

These test results complement those reported in EPRI Report 3002006078, *Testing to Confirm or Refine Gap Factor Utilized in Calculation of Minimum Vegetation Clearance Distances (MVCD): Test Results and Analysis*. The results were analyzed and compared against the value listed in the NERC FAC-003-3 Standard.

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List of Figures

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Section 1: Introduction

Background

In response to FERC Order No. 693, NERC submitted the reliability standard FAC-003-2 (Transmission Vegetation Management) for Commission approval. In the submittal, NERC proposed a methodology for calculating the minimum vegetation clearance distances (MVCD) based on the Gallet Equation and the use of a gap factor described within FAC-003-2. The NERC Standard contained a table of minimum vegetation clearance distances (MVCD) using a gap factor equal to 1.3.

On March 21, 2013, FERC issued its Final Rule of the "Revisions to Reliability Standard for Transmission Vegetation Management[1]," in which NERC Reliability Standard FAC-003-2 was approved. In the approval Order, NERC was directed "to conduct or contract testing to develop empirical data regarding the flashover distances between conductors and vegetation," and to use an approach based on "statistical analysis [that] would then evaluate the test results and provide empirical evidence to support an appropriate gap factor to be applied in calculating minimum clearance distances using the Gallet equation."

NERC retained EPRI to conduct these empirical tests designed to evaluate the appropriate gap factor within the Gallet equation for determining MVCDs in NERC FAC-003-2. An overall three stage empirical testing plan was designed and executed, based on NERC oversight and industry subject matter experts as well as FERC observers that included a range of switching impulse tests to validate the gap factor.

The tests were performed at EPRI's Lenox High Voltage Laboratory in Lenox, Massachusetts from June 23 through September 2, 2014, and are documented in a written report [10]. The tests were all performed on MVCD distances based on a gap factor of 1.3. Based on the test results, and the detailed analysis thereof, NERC concluded that the proposed minimum vegetation clearance distances (MVCD), based on a gap factor of 1.3, should be increased and the corresponding gap factor reduced to a more conservative value of 1.0.

---

[1] *Testing to Confirm or Refine Gap Factor Utilized in Calculation of Minimum Vegetation Clearance Distances (MVCD): Test Results and Analysis* April, 2015 3002006078

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

More specifically, the 230 kV MVCD to a vase shaped natural tree, based on gaps and impulses calculated for a gap factor of 1.3, did not pass the withstand test performed at expected transient overvoltage level given in the MVCD FAC003-2. Photographs of the flashovers that occurred during the withstand test are shown in Figure 1-1.

Figure 1-1
Flashovers to Vase, 230 kV, Vertical, Natural Vegetation

A series of communications and webinars were completed in early 2015, and an "Industry Advisory FAC-003-3 Minimum Vegetation Clearance" was issued in early May containing the revised MVCD tables [11] based on a gap factor of 1.0.

NERC staff retained EPRI to perform these supplementary impulse tests to validate that a MVCD based on a gap factor of 1.0 is empirically able to statistically withstand the expected transient overvoltage level provided in FAC-003-2. The testing plan used the configuration that yielded the lowest withstand strength in the original testing, which was the vase shaped tree at 230 kV in a vertical configuration. The tests were performed in the spring of 2015, when the trees at the Lenox facility are in full leaf bloom.

This document is intended to document the empirical testing plan and results for validating the adjusted gap factor of 1.0 at the Lenox facility to confirm the appropriate MVCD values within the FAC-003 standard. Accordingly this document supplements the earlier testing conducted by EPRI.

Objective

The objective of this project is to confirm, or if necessary, advise NERC of the adequacy of the gap factor (kg) of 1.0 as a basis for the calculation of minimum vegetation clearance distances (MVCD) utilizing the method documented in NERC Reliability Standard FAC-003-3.

Approach

Switching impulse testing was performed to determine the critical flashover voltage (CFO, U_{50}) for the revised MVCD applicable to a 230 kV system and a natural, vase-shaped tree, for a tree to conductor distance calculated using a gap factor of 1.0. The gap factor (k_g) is calculated and compared against the 1.0 value proposed by FERC and NERC. A range of canopy diameters was tested to confirm that the choice of gap factor is acceptable for all tree diameters.

Overview of Report

The test methodology is described in Chapter 2 and the test results are presented and compared in Chapter 3. The conclusions are summarized in Chapter 4. In Appendix A example calculations are presented for minimum vegetation clearance distances according to the methodology proposed in the "Transmission Vegetation Management NERC Standard FAC-003-2 Technical Reference". The resulting MVCD tables are also included.

Section 2: Switching Impulse Testing

Objective

Switching Impulse tests have been performed to determine the flashover strength of a representative conductor-to-natural vegetation gap configuration to validate the revision of the gap factor used in determining minimum vegetation clearance distances (MVCD). The critical flashover voltage (CFO) was determined for each configuration.

Approach

Switching impulse testing was performed on natural trees under the Lenox test line to determine the critical flashover voltage (CFO) of the air gap between a conductor and natural trees. The distance between the conductor and the tree was calculated using a gap factor of 1.0. The gap factor (k_g) was then calculated based on test results and compared against the value utilized in the revised MVCD calculation [11].

Test location and connections to test object

Switching impulse tests were performed on a natural, vase-shaped tree, and a conductor to tree distance applicable to a Nominal System Voltage of 230 kV [11]. For these tests a tree with an appropriate shape was selected from the specimens available at the test location under the Lenox UHV span, across the river from the impulse generator as shown in Figure 2-1. The test location was selected to replicate the withstand tests performed during the 2014 minimum vegetation clearance tests [10].

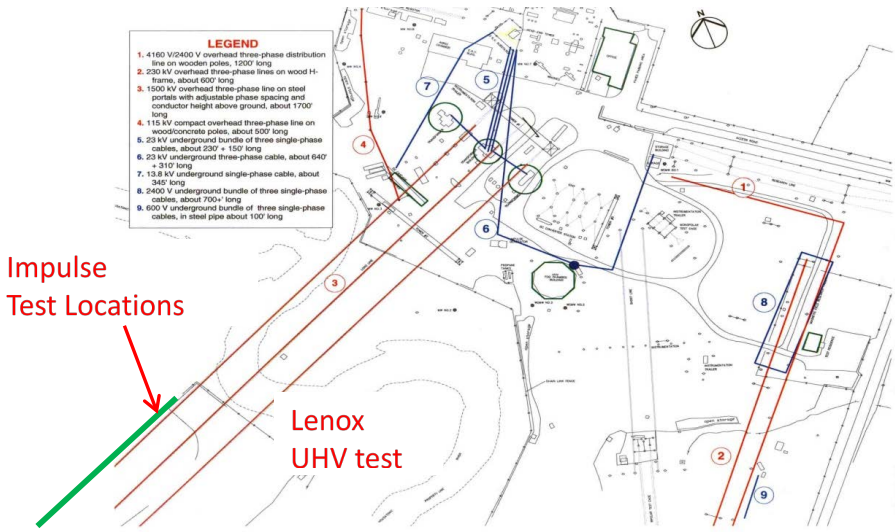

Figure 2-1
Test Location for Natural Trees

Test setup

The test ***setup*** was the same as that previously used for the withstand tests during the 2014 minimum vegetation clearance distance tests [10]. The tree was tested without the addition of a metal rod or wooden dowel to serve as ground electrode. A general view of the test setup is shown in Figure 2-2.

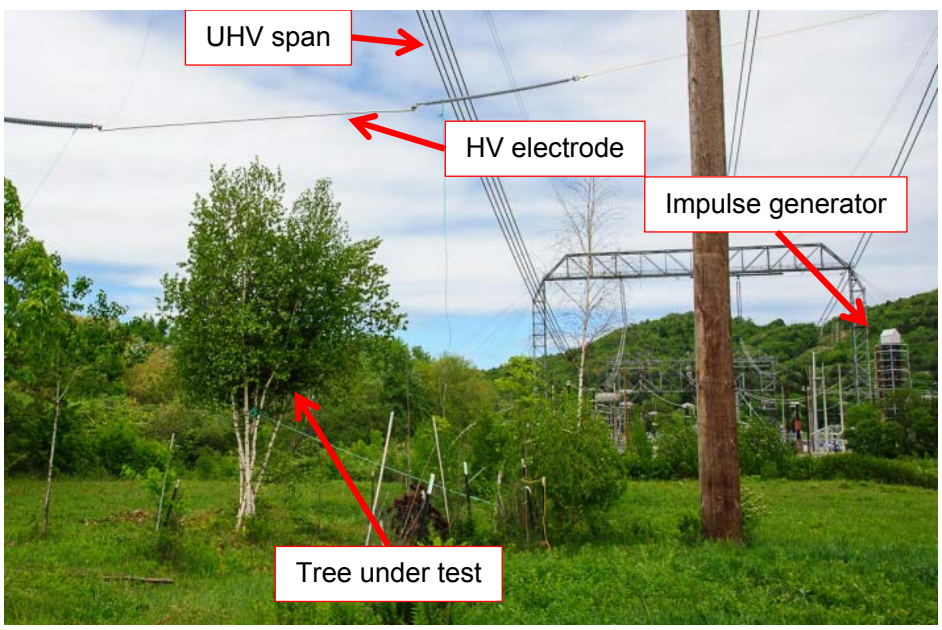

Figure 2-2
Photograph of test set up. Vertical gap distances were set using a winch.

Energized electrode definition:

The energized electrode was an aluminum tube representing a typical phase conductor of a 230 kV system voltage level. The characteristics and dimensions of the aluminum tube were the same as was used for the 2014 minimum vegetation clearance tests and are given in Table 2-1.

Table 2-1
Phase conductor definition for the supplemental minimum vegetation clearance tests

	230 kV
Bundle (# conductors per phase)	1
Bundle spacing	n/a
Bundle height above ground (NESC)	Minimum 25.2 feet
Conductor size (Outer Diameter)	1.0 in

To minimize interference with the electric field profile between the simulated conductor and the tree, the connection from the impulse generator to the electrode were made as far as practical from the Artificial Vegetation Configuration as shown conceptually in Figure 2-3. The length of the aluminum tube was chosen to be sufficient to minimize any end effects.

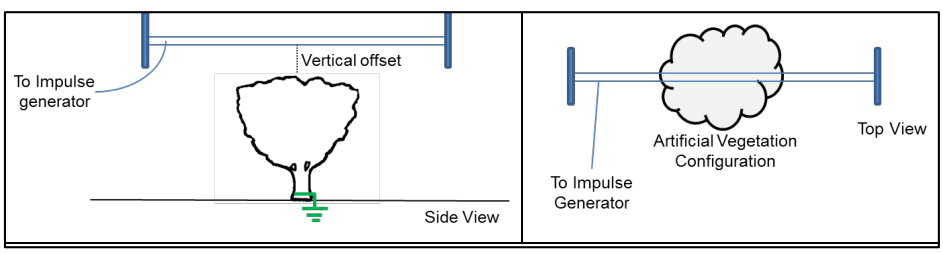

Figure 2-3
Connections to the conductor for the supplemental minimum vegetation clearance tests simulating the Grow-in condition (i.e. vertical gap to artificial vegetation)

Gap Size

The shortest distance from the bottom/side of the conductor to the top of the tree crown is defined in Table 2-2.

Table 2-2
Gap sizes for the supplemental minimum vegetation clearance tests.

	230 kV
Gap (feet)	4.2
Gap (m)	1.30

Note: This distance was obtained from the "Industry Advisory FAC-003-3 Minimum Vegetation Clearance Distances": Table 1 – Table of MVCD value at a 1.0 gap factor (in U.S. customary units) [11]. The values "Over 1,000 ft. up to 2,000 ft." applies as the Lenox test site is 1200 feet above sea level

Test circuit

Applicable Standards

IEEE Std. 4 – 2013

Wave shape

The switching impulse tests have been performed with the critical wave shape defined for the 2014 MVCD tests [10]. The following wave shape parameters apply:

- Time to peak (T_p): 100 µs ± 20%
- Virtual time to half-value (T_2): 2500 µs ± 60%

The definition of these wave parameters are presented in Figure 2-4.

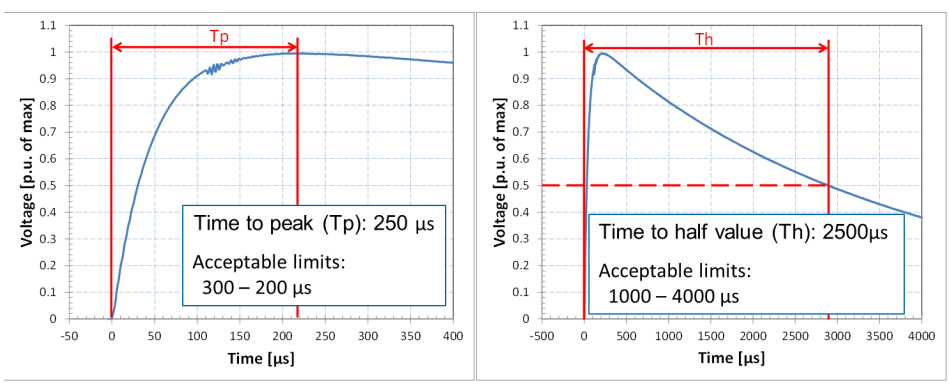

Figure 2-4
Definition of the Standard Switching Impulse as per IEEE Standard 4.

Marx Generator setup

The lightning impulse tests have been performed with the EPRI 28 stage conventional Marx generator circuit as shown in Figure 2-5. It has the following internal parameters:

- Capacitance per stage: 0.5 μF
- Self-inductance per stage: 3.64 μH
- Internal resistance per stage: 0.2 Ω

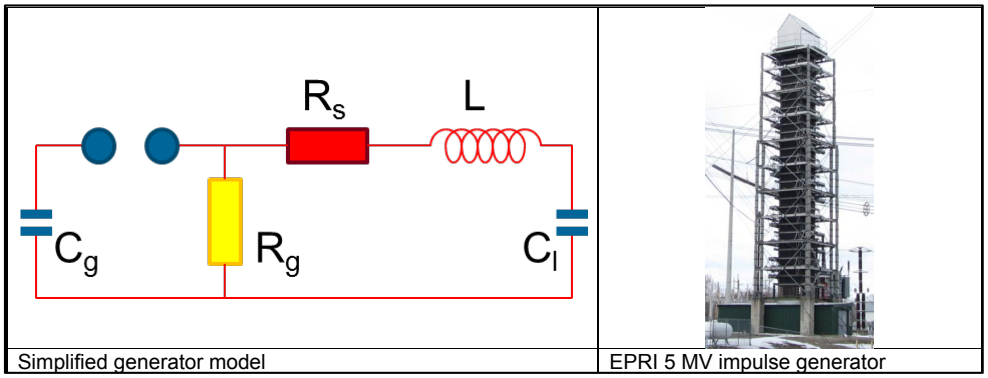

Figure 2-5
The test circuit for Lightning Impulse Tests

The following circuit component values have been selected for the impulse generator to produce required lightning impulse wave shapes:

- Number of Stages: 17
- Generator capacitance C_g: 29.4 nF (0.5 μF per stage)
- Assumed Capacitance for test setup C_l: 6.2 nF
- Front shaping resistance R_s: 3.42 kΩ
- Discharge resistance R_g: 105 kΩ

Test Ambient Conditions

The tests were performed under dry conditions. This means:

- No precipitation of any kind is allowed.
- Relative humidity less than 80%
- The ratio of the absolute humidity (h) to the relative air density (δ) shall not exceed 15 g/m^3.
- The ambient temperature shall be between 0°C (32°F) and 40°C (104°F).
- Wind: The tree top was stabilized with rope approximating an inverted V so that the relative distance between electrode and tree top did not vary significantly during windy conditions.

Test methodology

The critical flashover voltage (CFO, or U_{50}), was determined by the Up-Down method (UDM). For the UDM at least 20 impulses shall be applied including the first flashover. The applied voltage was increased by one step after each withstand and lowered by one step after each flashover. The step size was selected so that there was at least 4 voltage levels between full withstand and complete flashover.

During the test the development of the CFO estimate was monitored to determine if the flashover characteristics change during the test.

Evaluation of the results

The outcome of each test was analyzed in accordance with IEEE Std. 4, to determine estimates for the critical flashover voltage. This is done by fitting a normal distribution function through the test data points with the method of maximum likelihood. The fitted normal distribution function is described in terms of the 50% flashover voltage (Critical Flashover Voltage, CFO) and standard deviation. This method also provides an estimation of the 95% confidence interval, which is the interval for which there is a 95% probability that the true CFO will fall within. As such it gives an indication of the reliability of the CFO estimate.

The gap factor (k_g) was determined by expressing the CFO of the MVCD [CFO_{SOV} *(MVCD)*] relative to the flashover strength of a rod-plane gap [CFO_{SOV} *(Rod-Plane)*] with the same dimensions as follows.

$$CFO_{SOV}(MVCD) = k_g \times CFO_{SOV}(Rod\text{-}Plane) \qquad \textit{Eq. 2-1}$$

Where the CFO_{SOV} *(Rod-Plane)* is calculated with the Gallet Equation:

$$CFO_{SOV}(Rod\text{-}Plane) = 3400 / (1+8 / S) \qquad \textit{Eq. 2-2}$$

Where S is the gap size in meter [m].

Test specimens

The 2014 tests revealed the tree size (i.e. diameter of the crown) as an important parameter that may influence the flashover strength of the vegetation clearance. The results showed that wider trees resulted in lower flashover values. Furthermore, based on these results it was expected that the effect of diameter on flashover value would become less for very wide tree sizes as the gap factor approach that of a conductor-plane – i.e. k_g = 1.1. What constitutes a wide tree is related to the size of the air gap. The largest tree tested during 2014 (for the 230 kV, grow-in, vase shaped tree) had a ratio of tree diameter to gap length of 3.2:1. The test on this tree resulted in a gap factor in the range 1.08 to 1.11, which indicates that the diameter effect may have already saturated at this diameter to gap ratio.

For this testing, which is aimed at confirming the adequacy of the gap factor (k_g) of 1.0 as a basis for the calculation of MVCDs, it was thus important to perform the test on a large enough tree that the diameter effect no longer plays a significant role in withstand strength. The test on such a large tree would result in the lowest gap factor for that tree-conductor configuration. Considering the 2014 results it was decided to perform the verification tests on two tree sizes:

1. A "large tree" with a ratio of diameter to the gap length in the order of 4:1 For the gap size of 50" (4.2 ft.) this means that the diameter of the tree should be about 200"
2. A "small tree" with a diameter which is at least 50" less than that of the large tree. Based on a large tree diameter of 200", the diameter of small tree should be no larger than 150"

The supplemental tests were performed on a Natural, Vase-shaped tree, which was selected from the trees available for this purpose at the Lenox facility. This tree is shown in Figure 2-6 on the left. Additional freshly cut trees were lashed to the selected tree to achieve the required tree shape and size. This tree was also trimmed by cutting back the outgrowth to produce the characteristic "flat top" of a vase shaped tree. The modified tree, subjected to testing, is shown in Figure 2-6 on the right. Furthermore, steps were taken to ensure that all the trees used to build up the test specimen were bonded together electrically with copper wires and screws.

Figure 2-6
Vase Shaped Tree selected for testing.

As shown in Table 3-1, the switching impulse tests were performed on two tree diameters. The large tree, with a target diameter of 200", comprised a total of 7 trees lashed together. For the smaller diameter tree, two of the additional trees were removed. The dimensions of test object "as tested" were measured before and after the test and are presented in Figure 2-7.

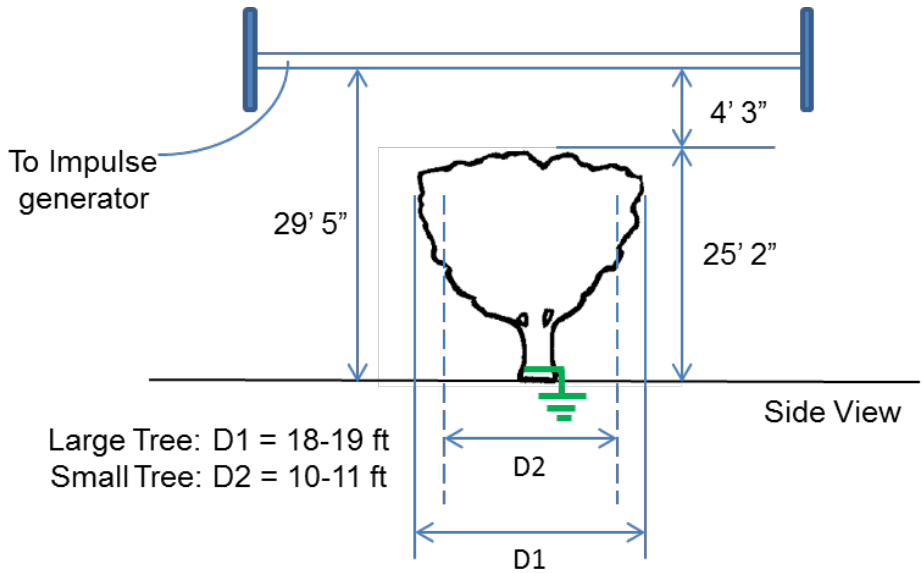

Figure 2-7
Actual test object dimensions and gap size

Section 3: Results

Overview of the tests performed

Testing was performed on May 21, 2015 as specified in Table 3-1.

Table 3-1
Overview of the switching impulse tests performed on natural trees.

Test #	Impulse	Voltage level (kV)	Gap configuration	Polarity	Diameter of tree top
1	Switching Impulse (≈100/2500 µs)	230 kV Nominal Voltage	Vase-shape tree	Positive	Large Tree D1 ≈ 220″
2			Grow-In (Vertical)		Small Tree D2 ≈ 125″

Wave shape

The following wave shape parameters were measured during testing:

- Time to peak (T_p): 107 µs
- Virtual time to half-value (T_2): 2470 µs

The applied impulse wave shape conformed therefore to the imposed requirements set out in Chapter 2. The definition of these wave parameters are again as presented in Figure 2-5.

Large Diameter Vase Shape: D1= 220″

The test sequence applied to the large diameter tree is presented in Figure 3-1. During this test a total of 36 impulses were applied to the test object. The first part of this test, comprising 15 impulses with increasing amplitude, is aimed at finding the voltage amplitude necessary for flashover. The next 21 impulses (from the first flashover onwards) form the up-down test. The data of these impulses are used to estimate the CFO (U_{50}).

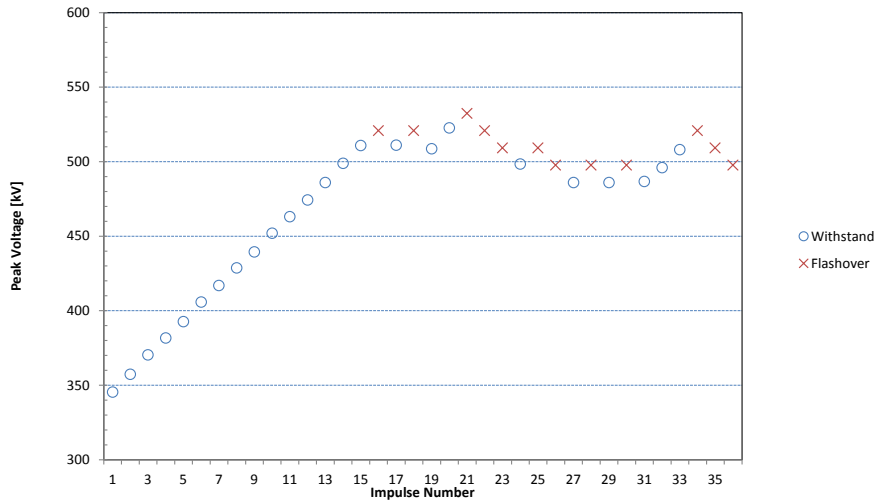

Figure 3-1
Test sequence for the up-down test on the large diameter tree

The results from the up-down test were analyzed with the method of maximum likelihood to estimate the critical flashover voltage (also named the V_{50}; or the voltage with a 50% flashover probability), and the standard deviation of the flashover characteristic. The 95% confidence interval of these parameters was also calculated.

The test results are presented in Table 3-2. Both the un-corrected and corrected values are presented. The corrected values refer to the flashover values which are corrected for atmospheric conditions as defined in IEEE Std. 4. The results are also presented graphically in Figure 3-2. Direct observation of impulse withstands and flash-overs indicate that the flashover characteristics do not change during this test.

The CFO, at sea-level, is therefore determined as 518 kV. This CFO is now compared to that of a rod-plane gap with the same gap length of 4.25 feet (1.30 m) which according to the Gallet equation is a CFO of 475 kV. The gap factor is therefore calculated as k_g = 518/475 = 1.09.

Photographs were taken of each flashover to the tree. The discharge channels were however not sufficiently luminous to be registered by the digital cameras used. Flashover was recognized by the sound and by the change in the impulse wave shape. The impulse wave shape associated with flashover had a notably shorter time to half value – on average $T_2 \approx 1000$ µs instead of the 2470 µs registered when no flashover occurred. This behavior is similar to that observed during the MVCD withstand tests performed in 2014[10].

This testing did not result in any visible damage to the tree.

Table 3-2
Estimate of the CFO of the test on the large diameter tree.

Porcelain Disc		As tested		Corrected to Standard conditions	
		U_{50} [kV]	Std. dev.[kV]	U_{50} [kV]	Std. dev.[kV]
STD Impulse	95% Conf. Min	477	8	488	9
	Estimate	**506**	**19**	**518**	**20**
	95% Conf. Max	534	–*	547	–

Note: * Too few data points were available to estimate the upper 95% confidence limit for the standard deviation.

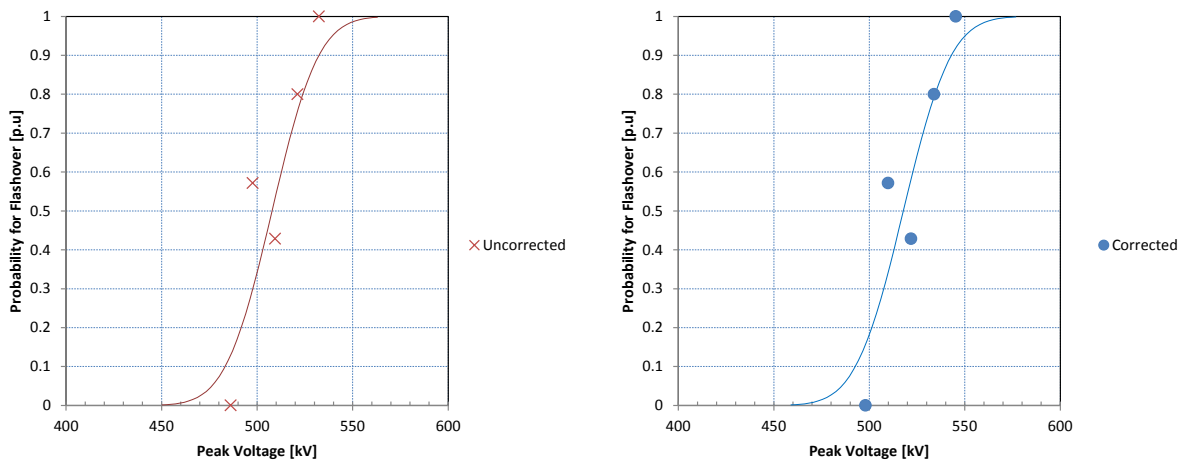

Figure 3-2
Test on the large diameter tree: Probability for Flashover as a Function of the Applied Switching Impulse Voltage.

Small Diameter Vase Shape: D2 = 125”

The test sequence applied to the small diameter tree is presented in Figure 3-3. During this test a total of 25 impulses were applied to the test object. The first part of this test, comprising 5 impulses with increasing amplitude, is aimed at finding the voltage amplitude necessary for flashover. The next 20 impulses (from the first flashover onwards) form the up-down test. The data of these impulses are used to estimate the CFO (U_{50}).

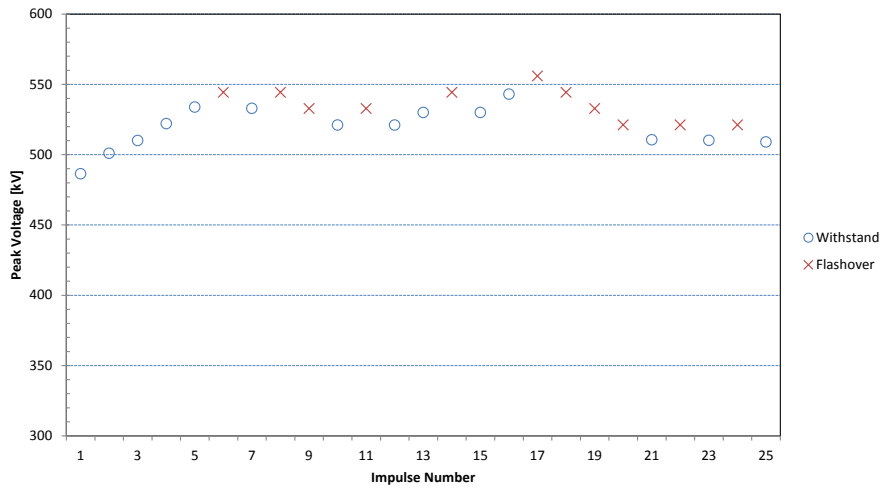

Figure 3-3
Test sequence for the up-down test on the small diameter tree

The results from the multiple level test were analyzed with the method of maximum likelihood to estimate the critical flashover voltage (also named the V_{50}; or the voltage with a 50% flashover probability), and the standard deviation of the flashover characteristic. The 95% confidence interval of these parameters was also calculated. The test results are presented in Table 3-3. Both the un-corrected and corrected values are presented. The corrected values refer to the flashover values which are corrected for atmospheric conditions as defined in IEEE Std. 4. The results are also presented graphically in Figure 3-2. Direct observation of impulse withstands and flash-overs indicate that the flashover characteristics do not change during this test.

Table 3-3
Estimate of the CFO of the test on the small diameter tree.

Porcelain Disc		As tested		Corrected to Standard conditions	
		U_{50} [kV]	Std. dev.[kV]	U_{50} [kV]	Std. dev.[kV]
STD Impulse	95% Conf. Min	507	7	523	8
	Estimate	**530**	**17**	**546**	**17**
	95% Conf. Max	556	–*	574	–*

Note: * Too few data points were available to estimate the upper 95% confidence limit for the standard deviation.

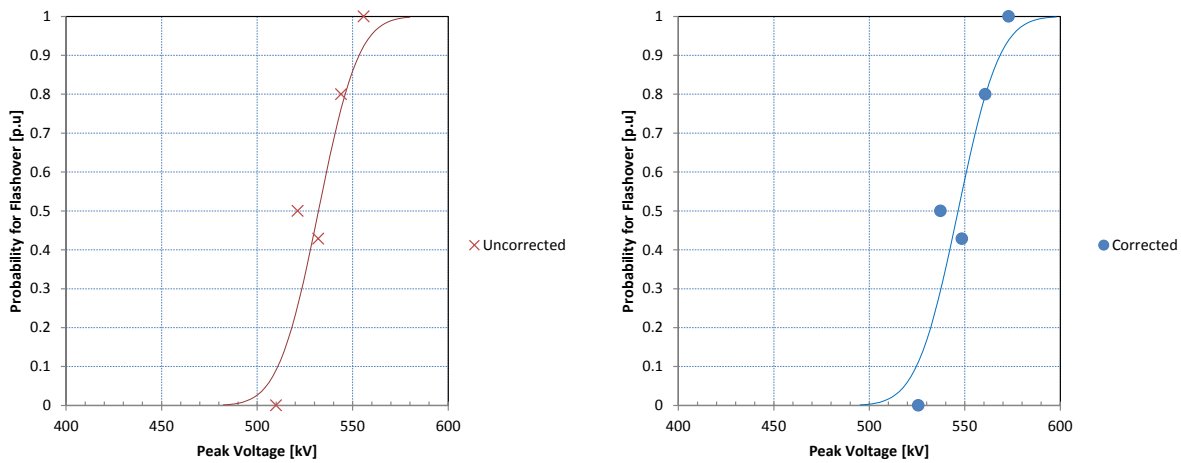

Figure 3-4
Test on the small diameter tree: Probability for Flashover as a Function of the Applied Switching Impulse Voltage.

The CFO, at sea-level, is therefore determined as 546 kV. This CFO is now compared to that of a rod-plane gap with the same gap length of 4.25 feet (1.30 m) which according to the Gallet equation should have a CFO of 475 kV. The gap factor is therefore calculated as k_g = 546/475 = 1.15.

The flashovers to the small diameter tree also did not have sufficient luminosity to be photographed and as before, flashover was recognized by the sound and the change in the impulse wave. Also during this test series no visible damage to the tree was observed.

After all tests were completed, a series of additional impulses were applied to the tree to determine if there was a change in flashover behavior at higher impulse amplitudes. It was found that visible discharges started occurring for voltage amplitude of 788 kV and above. An example of such a discharge is presented in Figure 3-5. While still faint, a discharge could be seen across the air gap and following along the tree stem to the ground – see detail photos on the right in Figure 3-5.

After these discharges a clear flashover path was observed on the tree stem. An example is shown in Figure 3-6.

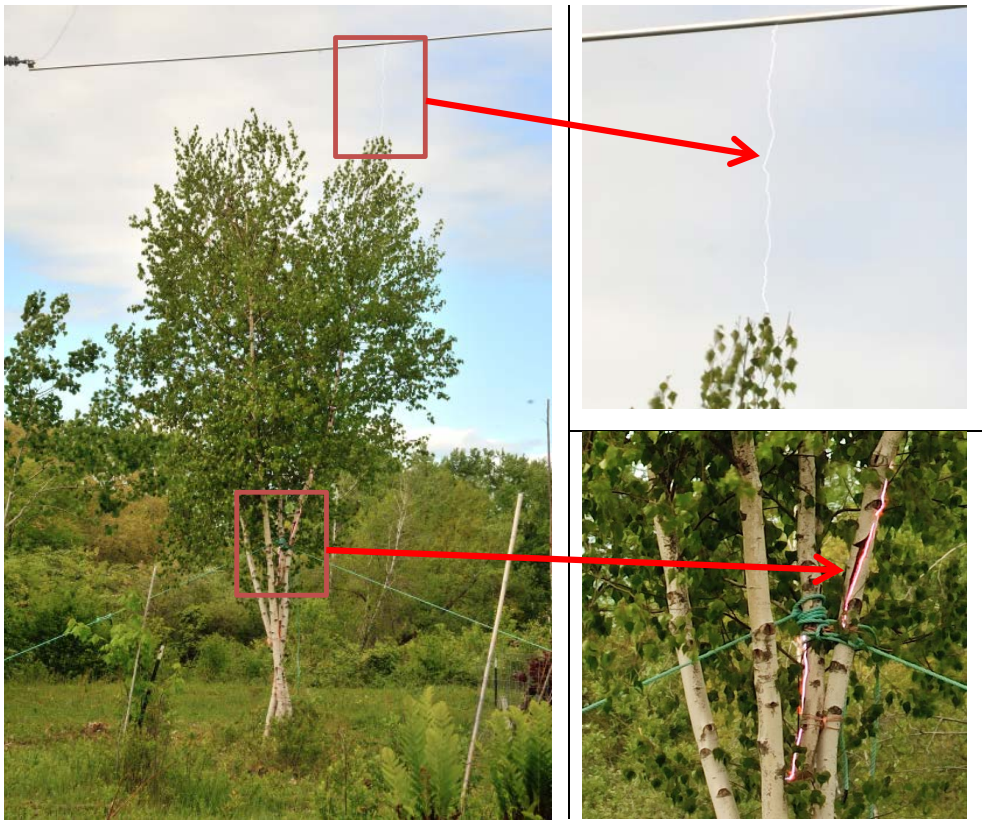

Figure 3-5
An example of a visible flashover to the tree that occurs at impulse voltages with amplitude of over 780 kV.

Figure 3-6
An example of the flashover track along the tree stem.

Comparison of results

For comparison purposes the test results. Corrected to standard atmospheric conditions are presented side by side in Table 3-4. From these values it can be seen that the flashover strength of the gap to the small diameter tree was 5.4% over that of the large diameter tree. The results are also shown graphically in Figure 3-7.

Table 3-4
Comparison of the flashover strength under switching impulse of two tree diameters: 230 kV Vertical Configuration, Vase Shaped Tree.

		Large Diameter	**Small Diameter**
Canopy Diameter	Feet	18-19	10-11
Critical flashover Voltage	[kV]	518	546
95% Confidence interval of the CFO estimate	[kV]	488 - 547	523 - 574
Normalized Standard Deviation*	[%]	4	3
Gap Factor	[p.u.]	1.09	1.15

Note: * a typical standard deviation for switching impulse tests is 6%.

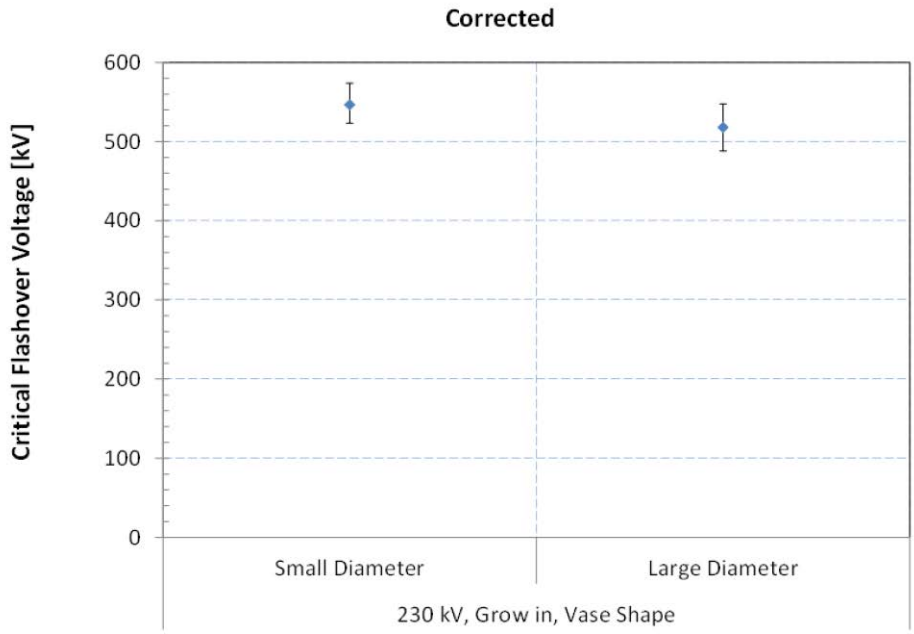

Figure 3-7
Comparison of the flashover strength under switching impulse of two tree diameters: 230 kV Vertical Configuration, Vase Shaped Tree. (The 95% confidence intervals of the CFO estimates are indicated by the error bars)

In Figure 3-8 a comparison is made of the 2014 and 2015 results for the 230 kV; grow in – vase shaped tree. This comparison is made on the basis of the ratio of the canopy diameter to the gap length because different gap lengths were tested in 2014 and 2015. The 95% confidence intervals for each gap factor are also shown to indicate the reliability of the estimated CFO values.

This comparison indicates that the gap factor stabilizes around 1.1 for ratios of the canopy diameter to the gap length greater than 3. It may therefore be concluded that the gap factor of a conductor over a wide tree approaches that of a conductor-plane gap, which is k_g = 1.1. This conclusion is made with some reservation considering the relatively few tests performed that resulted in a relatively large confidence region (i.e. 1.03 to 1.15). A conservative approach would be, therefore, to base the MVCD calculation on a gap factor which falls below the confidence region.

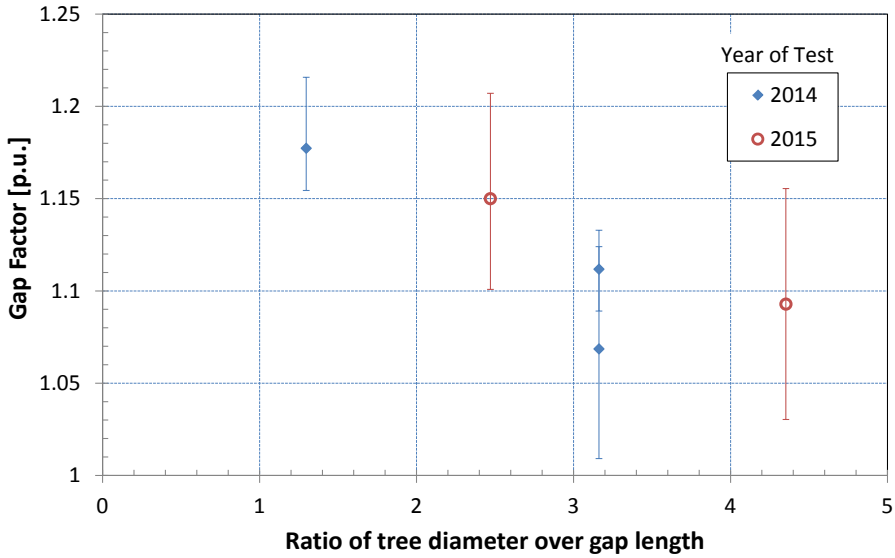

Figure 3-8
Comparison of the flashover strength under switching impulse for various tree diameters: 230 kV Vertical Configuration, Vase Shaped Tree. (The 95% confidence intervals of the CFO estimates are indicated by the error bars)

Based on these results presented above it can be confirmed that a gap factor (k_g) of 1.0 is an adequate basis for the calculation of minimum vegetation clearance distances (MVCD) according to the method documented in NERC Reliability Standard FAC-003-3.

Section 4: Conclusions

Switching impulse testing was performed to determine the critical flashover voltage (CFO, U_{50}) and associated gap factors for the revised MVCD applicable to a 230 kV system and a natural, vase-shaped tree with a tree to conductor distance based on the NERC approach based on a Gap factor of 1.0. A range of tree diameters were tested to confirm that the choice of gap factor is acceptable for all tree diameters.

Based on the results the following conclusions may be made:

- Within the confines of the testing performed (resulting in a large confidence region), it is concluded that the gap factor of a conductor over a large flat top tree approaches that of a conductor-plane gap, which is $k_g = 1.1$.
- The results confirm the adequacy of using a gap factor (k_g) of 1.0 as a conservative basis for the calculation of minimum vegetation clearance distances (MVCD) according to the method documented in NERC Reliability Standard FAC-003-2.

Section 5: References

[1] IEEE Standard for High-Voltage Testing Techniques IEEE Std. 4-2013 (Revision of IEEE Std. 4-1995) , 2013 , Page(s): 1 - 213

[2] IEEE Standard for the Measurement of Audible Noise From Overhead Transmission Lines, IEEE Std. 656-1992 , 1992

[3] IEC International Standard, Overhead lines - Requirements and tests for fittings, IEC 61284 ed2.0, 1997-09-17.

[4] EPRI, AC Transmission Line Reference Book – 200 kV and Above, Third Edition, EPRI, Palo Alto, CA: 2005. 1011974.

[5] FERC Ruling 777 FAC-003-2

[6] FAC-003-2 Compliance Filing

[7] Transmission Vegetation Management Standard FAC-003-2, Technical Reference 093011

[8] Applicability of the "Gallet Equation" to the Vegetation Clearances of NERC Reliability Standard FAC-003-2, PNNL-21220, 4/23/2012

[9] Transmission Vegetation Management Standard FAC-003-3: Transmission Vegetation Management.

[10] Testing to Confirm or Refine Gap Factor Utilized in Calculation of Minimum Vegetation Clearance Distances (MVCD) - Test Results and Analysis, EPRI, Palo Alto, CA: 2014. #3002006078.

[11] Industry Advisory FAC-003-3 Minimum Vegetation Clearance Distances

Appendix A: Calculation Examples

Introduction

This Appendix presents two calculation examples that follow the method for computing the minimum vegetation clearances (MVCD) proposed in the "Transmission Vegetation Management NERC Standard FAC-003-2 Technical Reference".

Example 1: A 345 kV transmission line that is located at a height above sea level not exceeding 500 ft (0.152 km).

Example 2: A 138 kV transmission line that is located at a height above sea level of between 6000 ft (1 829 m) and 7000 ft (2.134 km).

Both these examples are calculated on the basis of a gap factor (k_g) equal to 1.0.

Example 1

The MVCD is calculated for a 345 kV line at an altitude that does not exceed 500 feet (0.152 km). The maximum system voltage for this line is 362 kV.

Step 1 – Calculate the crest value of the expected transient overvoltage:

For in-service ac transmission lines of 362 kV and above the assumed maximum transient overvoltage factor is 1.4 p.u.

$$V_m = 1.4 \cdot 362\sqrt{\frac{2}{3}} = 414\ kV_{(crest)} \qquad \textit{Eq. A-1}$$

The required withstand voltage of the air gap must be equal to or greater than 414 kV_{crest}. Since the altitude is above sea level, an iterative process is followed to calculate the MVCD.

Step 2 – Calculate the initial estimate of the MVCD:

The following equation can be used to obtain an initial estimate of the MVCD.

$$D_i = \frac{8}{\frac{3400\ k_W\ k_g}{\left({}^{V}m/_{0.85}\right)} - 1} \qquad \textit{Eq. A-2}$$

In this case, V_m is equal to 414 kV, k_w = 1.037 and k_g = 1.0. Thus,

$$D_i = \frac{8}{\frac{3400 \cdot 1.037 \cdot 1.0}{\left(414/0.85\right)} - 1} = 1.283\ m \qquad \textit{Eq. A-3}$$

Step 3 – Calculate the critical flashover voltage for D_i at standard atmospheric conditions (CFOs):

$$CFO_s = k_w\ k_g \frac{3400}{1 + \frac{8}{(D)}}$$

$$CFO_s = 1.037 \cdot 1.0 \frac{3400}{1 + \frac{8}{(1.283)}} = 487.1 \qquad \textit{Eq. A-4}$$

Step 4 – Calculate the critical flashover voltage at a height above sea level of 500 ft (0.152 km) by applying the atmospheric correction factor.

$$G_0 = \frac{CFO_S}{500 \cdot D}$$

$$G_0 = \frac{487.1}{500 \cdot 1.283} = 0.760$$

$$m = 1.25 \cdot G_0(G_0 - 0.2)$$

$$m = 1.25 \cdot 0.760(0.760 - 0.2) = 0.531$$

$$CFO_A = CFO_s \cdot e^{-m\frac{A}{8.6}} \qquad \textit{Eq. A-5}$$

With A=0.152 km

$$CFO_A = 487.1 \cdot e^{-0.531\frac{0.152}{8.6}} = 482.5\ kV \qquad \textit{Eq. A-6}$$

Step 5 – Calculate the withstand voltage of the gap at a height above sea level of 500 ft (0.152 km).

$$V_m = CFO_A\left(1 - 3\frac{\sigma}{CFO_A}\right)$$

$$V_m = 482.5(1 - 3 \cdot 0.05) = 410.1\ kV \qquad \textit{Eq. A-7}$$

Step 6 – The withstand voltage (at altitude) is then compared to the maximum transient overvoltage. The calculated V_m (410.1) is less than 414 kV; thus, the clearance distance must be increased. A few iterations of steps 3 - 5 are required until the computed V_m = 414 kV. For this case it was found that D = 1.297 m (4.25 feet) yielded V_m = 414 kV. Using this clearance distance the following values were computed in Steps 3 to 5 of the final iteration.

Step 3 –

$$CFO_s = 1.037 \cdot 1.0 \frac{3400}{1+\frac{8}{(1.297)}} = 491.6 \qquad \textit{Eq. A-8}$$

Step 4 –

$$G_0 = \frac{491.6}{500 \cdot 1.297} = 0.758$$

$$m = 1.25 \cdot 0.758(0.758 - 0.2) = 0.529$$

$$CFO_A = 491.6 \cdot e^{-0.529\frac{0.152}{8.6}} = 487.1\ kV \qquad \textit{Eq. A-9}$$

Step 5 –

$$V_m = 487.1(1 - 3 \cdot 0.05) = 414.0\ kV \qquad \textit{Eq. A-10}$$

Thus, the minimum vegetation clearance distance (MVCD) for a maximum line to line ac operating voltage of 362 kV at 500 feet above sea level is 1.297 m (4.25 feet).

Example 2

The MVCD is calculated for a 138 kV line at an altitude of between 6000 feet (1.829 km) and 7000 feet (2.134 km). The maximum system voltage for this line is 145 kV.

Step 1 – Calculate the crest value of the expected transient overvoltage:

For in-service ac transmission lines of 145 kV and above the assumed maximum transient overvoltage factor is 2.0 p.u.

$$V_m = 2.0 \cdot 145\sqrt{\frac{2}{3}} = 237\ kV_{(crest)} \qquad \textit{Eq. A-11}$$

Step 2 – Calculate the initial estimate of the MVCD:

In this case, V_m is equal to 237 kV, k_w = 1.037 and k_g = 1.0. Thus,

$$D_i = \frac{8}{\frac{3400 \cdot 1.037 \cdot 1.0}{(237/0.85)} - 1} = 0.687\ m \qquad \textit{Eq. A-12}$$

Step 3 – Calculate the critical flashover voltage for D_i at standard atmospheric conditions (CFOs):

$$CFO_s = 1.037 \cdot 1.0 \frac{3400}{1+\frac{8}{(0.687)}} = 278.8 \qquad \textit{Eq. A-13}$$

Step 4 – Calculate the critical flashover voltage at a height above sea level of 7000 ft (2.134 km) by applying the atmospheric correction factor.

$$G_0 = \frac{278.8}{500 \cdot 0.687} = 0.812$$

$$m = 1.25 \cdot 0.812(0.812 - 0.2) = 0.620 \qquad \textit{Eq. A-14}$$

With A=2.134 km

$$CFO_A = 278.8 \cdot e^{-0.620\frac{2.134}{8.6}} = 239.0\ kV \qquad \textit{Eq. A-15}$$

Step 5 – Calculate the withstand voltage of the gap at a height above sea level of 700 ft (2.134 m).

$$V_m = 239.0(1 - 3 \cdot 0.05) = 203.2\ kV \qquad \textit{Eq. A-16}$$

Step 6 – The withstand voltage (at altitude) is then compared to the maximum transient overvoltage. The calculated V_m (203.2) is less than 237 kV; thus, the clearance distance must be increased. A few iterations of steps 3 to 5 yielded D = 0.809 m (2.65 feet) which corresponds to V_m = 237 kV. Using this clearance distance the Steps 3 to 5 resulted in the following.

Step 3 –

$$CFO_s = 1.037 \cdot 1.0 \frac{3400}{1 + \frac{8}{(0.809)}} = 323.6\ kV \qquad \textit{Eq. A-17}$$

Step 4 –

$$G_0 = \frac{323.6}{500 \cdot 0.809} = 0.800$$

$$m = 1.25 \cdot 0.800(0.800 - 0.2) = 0.601$$

$$CFO_A = 323.6 \cdot e^{-0.601\frac{2.134}{8.6}} = 278.8\ kV \qquad \textit{Eq. A-18}$$

Step 5 –

$$V_m = 278.8(1 - 3 \cdot 0.05) = 237.0\ kV \qquad \textit{Eq. A-19}$$

Thus, the minimum vegetation clearance distance (MVCD) for a maximum line to line ac operating voltage of 145 kV at 7000 feet above sea level is 0.809 m (2.65 feet).

Calculated Minimum Vegetation Clearance Distances

The methodology shown in the two examples, presented in the previous sections, has been used to calculate the MVCD for the all system voltages and altitudes. These calculations were based on a gap factor of 1.0. The MVCD values were calculated in metric units and then converted to distances in feet. The results are presented as follows:

Tables A-1 and A-2: MVCD for ac voltages in metric units

Tables A-3 and A-4: MVCD for ac voltages in US customary units

Table A-1
Minimum Vegetation Clearance Distances (MVCD) for Alternating Current Voltages for altitudes below 8,000 ft calculated at a gap factor of 1.0 (in metric units)

Gap Factor	(AC) Nominal System Voltage (KV)	(AC) Max-imum System Voltage (kV)	Transient Overvoltage Factor (p.u.)	MVCD [m] Over sea level up to 500 ft	MVCD [m] Over 500 ft up to 1,000 ft	MVCD [m] Over 1,000 ft up to 2,000 ft	MVCD [m] Over 2,000 ft up to 3,000 ft	MVCD [m] Over 3,000 ft up to 4,000 ft	MVCD [m] Over 4,000 ft up to 5,000 ft	MVCD [m] Over 5,000 ft up to 6,000 ft	MVCD [m] Over 6,000 ft up to 7,000 ft	MVCD [m] Over 7,000 ft up to 8,000 ft
			Altitude (ft)	**500**	**1000**	**2000**	**3000**	**4000**	**5000**	**6000**	**7000**	**8000**
			Altitude (km)	**0.152**	**0.305**	**0.610**	**0.915**	**1.220**	**1.524**	**1.829**	**2.134**	**2.439**
1.00	**765**	**800**	**1.4**	3.53966	3.56786	3.62410	3.68013	3.73593	3.79149	3.84680	3.90186	3.95665
1.00	**500**	**550**	**1.4**	2.14619	2.16684	2.20825	2.24979	2.29143	2.33318	2.37501	2.41690	2.45885
1.00	**345**	**362**	**1.4**	1.29660	1.31072	1.33917	1.36790	1.39690	1.42616	1.45567	1.48542	1.51539
1.00	**287**	**302**	**2**	1.59201	1.60861	1.64198	1.67558	1.70942	1.74347	1.77772	1.81216	1.84678
1.00	**230**	**242**	**2**	1.22819	1.24170	1.26895	1.29648	1.32428	1.35236	1.38068	1.40926	1.43808
1.00	**161**	**169**	**2**	0.82120	0.83082	0.85028	0.87002	0.89005	0.91037	0.93095	0.95182	0.97295
1.00	**138**	**145**	**2**	0.69536	0.70366	0.72049	0.73759	0.75496	0.77260	0.79051	0.80869	0.82714
1.00	**115**	**121**	**2**	0.57296	0.57994	0.59409	0.60850	0.62316	0.63807	0.65324	0.66866	0.68433
1.00	**88**	**100**	**2**	0.46595	0.47173	0.48345	0.49539	0.50757	0.51998	0.53262	0.54548	0.55858
1.00	**69**	**72**	**2**	0.33213	0.33633	0.34488	0.35362	0.36254	0.37164	0.38094	0.39042	0.40010

Table A-2
Minimum Vegetation Clearance Distances (MVCD) for Alternating Current Voltages for altitudes from 8,000 ft to 15,000 ft calculated at a gap factor of 1.0 (in metric units)

Gap Factor	(AC) Nominal System Voltage (KV)	(AC) Max-imum System Voltage (kV)	Transient Overvoltage Factor (p.u.)	MVCD [m] Over 8,000 ft up to 9,000 ft	MVCD [m] Over 9,000 ft up to 10,000 ft	MVCD [m] Over 10,000 ft up to 11,000 ft	MVCD [m] Over 11,000 ft up to 12,000 ft	MVCD [m] Over 12,000 ft up to 13,000 ft	MVCD [m] Over 13,000 ft up to 14,000 ft	MVCD [m] Over 14,000 ft up to 15,000 ft
			Altitude (ft)	**9000**	**10000**	**11000**	**12000**	**13000**	**14000**	**15000**
			Altitude (km)	**2.744**	**3.049**	**3.354**	**3.658**	**3.962**	**4.267**	**4.572**
1.00	**765**	**800**	**1.4**	4.01117	4.06542	4.11939	4.17307	4.22646	4.27956	4.33236
1.00	**500**	**550**	**1.4**	2.50085	2.54287	2.58491	2.62695	2.66899	2.71102	2.75301
1.00	**345**	**362**	**1.4**	1.54558	1.57599	1.60658	1.63737	1.66833	1.69946	1.73075
1.00	**287**	**302**	**2**	1.88156	1.91649	1.95156	1.98677	2.02209	2.05752	2.09304
1.00	**230**	**242**	**2**	1.46712	1.49638	1.52585	1.55552	1.58538	1.61542	1.64563
1.00	**161**	**169**	**2**	0.99434	1.01599	1.03789	1.06004	1.08244	1.10506	1.12792
1.00	**138**	**145**	**2**	0.84584	0.86480	0.88402	0.90348	0.92320	0.94315	0.96334
1.00	**115**	**121**	**2**	0.70024	0.71641	0.73282	0.74948	0.76637	0.78351	0.80088
1.00	**88**	**100**	**2**	0.57191	0.58547	0.59926	0.61328	0.62752	0.64200	0.65670
1.00	**69**	**72**	**2**	0.40996	0.42003	0.43028	0.44074	0.45139	0.46223	0.47328

Table A-3
Minimum Vegetation Clearance Distances (MVCD) for Alternating Current Voltages for altitudes below 8,000 ft calculated at a gap factor of 1.0 (in U.S. customary units)

Gap Factor	(AC) Nominal System Voltage (KV)	(AC) Max-imum System Voltage (kV)	Transient Overvoltage Factor (p.u.)	MVCD [ft] Over sea level up to 500 ft	MVCD [ft] Over 500 ft up to 1,000 ft	MVCD [ft] Over 1,000 ft up to 2,000 ft	MVCD [ft] Over 2,000 ft up to 3,000 ft	MVCD [ft] Over 3,000 ft up to 4,000 ft	MVCD [ft] Over 4,000 ft up to 5,000 ft	MVCD [ft] Over 5,000 ft up to 6,000 ft	MVCD [ft] Over 6,000 ft up to 7,000 ft	MVCD [ft] Over 7,000 ft up to 8,000 ft
			Altitude (ft)	**500**	**1000**	**2000**	**3000**	**4000**	**5000**	**6000**	**7000**	**8000**
			Altitude (km)	**0.152**	**0.305**	**0.610**	**0.915**	**1.220**	**1.524**	**1.829**	**2.134**	**2.439**
1.00	**765**	**800**	**1.4**	11.61307	11.70558	11.89011	12.07392	12.25698	12.43926	12.62073	12.80136	12.98113
1.00	**500**	**550**	**1.4**	7.04132	7.10907	7.24492	7.38119	7.51783	7.65479	7.79202	7.92947	8.06711
1.00	**345**	**362**	**1.4**	4.25393	4.30025	4.39360	4.48787	4.58301	4.67901	4.77582	4.87341	4.97176
1.00	**287**	**302**	**2**	5.22314	5.27758	5.38706	5.49732	5.60833	5.72005	5.83242	5.94541	6.05898
1.00	**230**	**242**	**2**	4.02950	4.07383	4.16322	4.25354	4.34476	4.43686	4.52980	4.62356	4.71809
1.00	**161**	**169**	**2**	2.69424	2.72580	2.78963	2.85441	2.92013	2.98676	3.05431	3.12276	3.19208
1.00	**138**	**145**	**2**	2.28135	2.30861	2.36380	2.41990	2.47689	2.53478	2.59355	2.65320	2.71371
1.00	**115**	**121**	**2**	1.87980	1.90270	1.94913	1.99639	2.04449	2.09342	2.14317	2.19376	2.24516
1.00	**88**	**100**	**2**	1.52871	1.54766	1.58611	1.62531	1.66526	1.70597	1.74743	1.78964	1.83262
1.00	**69**	**72**	**2**	1.08966	1.10346	1.13151	1.16017	1.18943	1.21930	1.24979	1.28091	1.31265

Table A-4
Minimum Vegetation Clearance Distances (MVCD) for Alternating Current Voltages for altitudes from 8,000 ft to 15,000 ft calculated at a gap factor of 1.0 (in U.S. customary units)

Gap Factor	(AC) Nominal System Voltage (KV)	(AC) Max-imum System Voltage (kV)	Transient Overvoltage Factor (p.u.)	MVCD [ft] Over 8,000 ft up to 9,000 ft	MVCD [ft] Over 9,000 ft up to 10,000 ft	MVCD [ft] Over 10,000 ft up to 11,000 ft	MVCD [ft] Over 11,000 ft up to 12,000 ft	MVCD [ft] Over 12,000 ft up to 13,000 ft	MVCD [ft] Over 13,000 ft up to 14,000 ft	MVCD [ft] Over 14,000 ft up to 15,000 ft
			Altitude (ft)	**9000**	**10000**	**11000**	**12000**	**13000**	**14000**	**15000**
			Altitude (km)	**2.744**	**3.049**	**3.354**	**3.658**	**3.962**	**4.267**	**4.572**
1.00	**765**	**800**	**1.4**	13.16002	13.33800	13.51505	13.69117	13.86634	14.04054	14.21377
1.00	**500**	**550**	**1.4**	8.20488	8.34275	8.48067	8.61861	8.75654	8.89441	9.03220
1.00	**345**	**362**	**1.4**	5.07082	5.17056	5.27094	5.37195	5.47353	5.57567	5.67832
1.00	**287**	**302**	**2**	6.17309	6.28770	6.40277	6.51827	6.63415	6.75038	6.86692
1.00	**230**	**242**	**2**	4.81338	4.90938	5.00607	5.10342	5.20138	5.29994	5.39905
1.00	**161**	**169**	**2**	3.26226	3.33330	3.40516	3.47783	3.55130	3.62554	3.70053
1.00	**138**	**145**	**2**	2.77508	2.83729	2.90033	2.96419	3.02886	3.09432	3.16056
1.00	**115**	**121**	**2**	2.29739	2.35042	2.40427	2.45891	2.51434	2.57056	2.62755
1.00	**88**	**100**	**2**	1.87635	1.92083	1.96607	2.01206	2.05880	2.10629	2.15452
1.00	**69**	**72**	**2**	1.34502	1.37804	1.41169	1.44599	1.48093	1.51652	1.55276

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Exhibit F

Summary of Development History and Record of Development

Summary of Development History

Summary of Development History

The development record for proposed Reliability Standard FAC-003-4 is summarized below.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[1] The technical expertise of the ERO is derived from the standard drafting team selected to lead each project in accordance with Section 4.3 if the NERC Standards Process Manual.[2] For this project, the standard drafting team consisted of industry experts, all with a diverse set of experiences. A roster of the standard drafting team members is included in Exhibit F.

II. Standard Development History

A. Standard Authorization Request Development

A Standard Authorization Request ("SAR") was submitted to the Standards Committee ("SC") on August 19, 2015 and accepted by SC on October 29, 2015.

B. First Posting - Comment Period, Initial Ballot and Non-Binding Poll

Proposed Reliability Standard FAC-003-4 was posted for a 45-day public comment period from October 30, 2015 through December 16, 2015, with an initial ballot held from December 7, 2015 through December 16, 2015. Two documents were posted for guidance with the first draft, including the Unofficial Comment Form, and the SAR. The initial ballot received 85.38% quorum, and 82.56% approval. There were 37 sets of

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[1] Section 215(d)(2) of the Federal Power Act; 16 U.S.C. §824(d) (2) (2012).

[2] The NERC *Standard Processes Manual* is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

comments, including comments from approximately 123 different individuals and approximately 89 companies, representing 8 of the 10 industry segments.[3]

C. Final Ballot

Proposed Reliability Standard FAC-003-4 was posted for a 10-final ballot period from January 29, 2016 through February 8, 2016. The proposed Reliability Standard received 90.03% quorum and 96.18% approval.

D. Board of Trustees Adoption

Proposed Reliability Standard FAC-003-4 was adopted by the NERC Board of Trustees on February 11, 2016. The SC approved the errata on March 9, 2016.[4]

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[3] NERC, *Consideration of Comments*, Project 2010-07.1, (January 28, 2016), *available at* *http://www.nerc.com/pa/Stand/Project%202010071%20Vegetation%20Management%20DL/FAC-003-4_VegMan_Consideration_of_Comments_1%2014%202016.pdf*.

[4] An errata was made the FAC-003-4 Reliability Standard and was approved by the SC on March 9, 2016, *available at*, *http://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC%20Agenda%20Package%20-%20March%209%202016.pdf*.

Complete Record of Development

Related Files

Status
A final ballot for **FAC-003-4 Transmission Vegetation Management** is open through **8 p.m. Eastern, Monday, February 8, 2016**. The voting results for the standard will be posted and announced after the ballots close. If approved, the standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Background
In FERC Order No. 777, the Commission directed NERC to "conduct or contract testing to obtain empirical data and submit a report to the Commission providing the results of the testing." NERC retained the Electric Power Research Institute (EPRI) to conduct testing to support appropriate Minimum Vegetation Clearance Distances (MVCDs) specified in NERC Reliability Standard FAC-003-3. The MVCDs in the Standard are calculated based on application of the Gallet equation which incorporates a gap factor. The preliminary test result findings determined that the gap factor applied in the Gallet equation requires adjustment. The resulting adjustment will increase MVCDs for all alternating current system voltages covered by Table 2 of the Standard.

Standard(s) Affected: FAC-003-3 Transmission Vegetation Management

Purpose / Industry Need
The purpose of the revised standard is to address the findings of the Electric Power Research Institute (EPRI) report, which was a part of the Federal Energy Regulatory Commission (FERC) Order No. 777 directive. The revised standard uses an updated gap factor of 1.0 in the Gallet equation to develop minimum vegetation clearance distances to decrease vegetation related events.

Draft	Actions	Dates	Results	Consideration of Comments
Final Draft FAC-003-4 Clean **(22)**| Redline to Last Posted **(23)** Redline to Last Approved **(24)** Implementation Clean Clean **(25)**| Redline to Last Posted **(26)**	Final Ballot Info **(27)** Vote	01/29/16 – 02/08/16	Summary **(28)** Ballot Results **(29)**	
Draft 1 FAC-003-4 Clean **(8)**| Redline to Last Approved **(9)** Implementation Plan **(10)** **Supporting Materials** Unofficial Comment Form (Word) **(11)** Standard Authorization Request (SAR) Clean **(12)**| Redline to Last Posted **(13)**	Initial Ballot Updated Info **(14)** Info **(15)** Vote *A non-binding poll for the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) will not be conducted due to the fact that only non-substantive changes were made to the requirements, and no changes made to the VRFs and VSLs.	12/07/15 – 12/16/15	Summary **(18)** Ballot Results **(19)**	
	Comment Period Info **(16)** Submit Comments	10/30/15 – 12/16/15	Comments Received **(20)**	Consideration of Comments **(21)**

Draft Reliability Standard Audit Worksheet (RSAW) *This draft RSAW has no substantive changes from the RSAW for FAC-003-3.				
	Join Ballot Pool	10/30/15 – 11/30/15		
	Info **(17)** Send RSAW feedback to: RSAWfeedback@nerc.net	11/13/15 – 12/16/15		
Standards Committee accepted the Standard Authorization Request on October 29, 2015				
Standard Authorization Request **(3)** **Supporting Materials** Unofficial Comment Form (Word) **(4)**	Comment Period Info **(5)** Submit Comments	08/24/15 - 09/28/15	Comments Received **(6)**	Consideration of Comments **(7)**
Drafting Team Nominations **Supporting Materials** Unofficial Nomination Form (Word) **(1)**	Nomination Period Info **(2)** Submit Nominations	08/24/15 - 09/08/15		

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Nomination Form

Nominations Solicited For Project 2010-07.1 Vegetation Mangement – FAC-003

Please complete the electronic nomination form as soon as possible, but no later than **8:00pm on September 8, 2015.** This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form. If you have any questions, please contact Jordan Mallory (via email) or at 404-446-9733 (Jordan).

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in the review or drafting team meetings if appointed by the Standards Committee. If appointed, you are expected to attend most of the face-to-face drafting team meetings as well as participate in all the team meetings held via conference calls. Failure to do so may result in your removal from the review or drafting team.

The time commitment for this project is expected to be one face-to-face meeting a month (on average two full working days) with conference calls scheduled as needed to meet the agreed upon timeline the review or drafting team sets forth. Review and drafting teams also will have side projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the review and drafting team efforts is outreach. Members of the teams should be conducting outreach during development prior to posting to ensure all issues can be discussed and resolved.

Nominations are being sought for Project 2010-07.1 Vegetation Management. Previous review or drafting team experience is beneficial but not required. A brief description of the desired qualifications and other pertinent information for the project is included below. The project is expected to be presented at the November 2015 Board of Trustees meeting for adoption.

Project 2010-07.1 Vegetation Management

The purpose of the proposed project is to address the findings of the Electric Power Research Institute (EPRI) report, which was a part of the Federal Energy Regulatory Commission (FERC) Order No. 777[1] directive.

In Order No. 777, the FERC directed NERC to provide empirical data validating the gap factor for flashover distances between conductors and vegetation used in the Gallet equation to calculate Minimum Vegetation Clearance Distances (MVCDs) in NERC Reliability Standard FAC-003-2. In the order, FERC directed NERC to submit: (1) a schedule for testing; (2) the scope of work; (3) funding solutions; and (4) a deadline for

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

submitting a final report on the test results to FERC, along with interim reports if a multiyear study is conducted.[2] NERC contracted the EPRI and performed a collaborative research project to complete the work. NERC submitted a compliance filing on July 12, 2013,[3] which FERC accepted on September 4, 2013.[4]

In January 2014, NERC formed an advisory group to develop the scope of work for the project. This team of subject matter experts assisted in developing the test plan, which included monitoring the testing and analyzing the test results to be provided in a final report. The advisory team was comprised of NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulator characteristics, and vegetation management. The project's scope of work and the detailed test plan were finalized in March 2014.

The testing project commenced in April 2014 and continued through October 2014. EPRI completed the prescribed tests to validate the gap factor applied in the Gallet equation. NERC filed an informational filing with FERC on July 31, 2014,[5] that contained the results of the testing work completed to date. The initial analysis, containing preliminary conclusions and recommendations, concluded in early 2015. Based on the preliminary results, the gap factor used in the Gallet equation required modification from 1.3 to 1.0, which would increase the MVCD values compared to those specified in the existing standard.

NERC, through EPRI, performed additional tests in 2015 to finalize the gap-factor verification, communicate the research findings to industry through webinars and committee meetings, and issued an industry advisory alert in May 2015.[6] Final testing was completed and an EPRI report was posted on July 21, 2015. The report determined "that the proposed minimum vegetation clearance distances (MVCD), based on a gap factor of 1.3, should be increased and the corresponding gap factor reduced to a more conservative value of 1.0."[7]

Standards affected: The project will modify FAC-003-3.

NERC is seeking a cross section of the industry to participate on the team, but in particular is seeking individuals who have experience and expertise with vegetation management in the United States and/or Canada.

Experience with developing standards inside or outside (e.g., IEEE, NAESB, ANSI, etc.) of the NERC process is beneficial, but is not required, and should be highlighted in the information submitted, if applicable.

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[2] *Id*. at P 61.
[3] Compliance Filing of NERC, Docket No. RM12-4-000 (Jul. 12, 2013).
[4] *N. Am. Elec. Reliability Corp.*, Docket No. RM12-4-001 (Sept. 4, 2013) (delegated letter order).
[5] Informational Filing of NERC, Docket Nos. RM12-4-000 and RM12-4-001 (Jul. 31, 2014).
[6] Industry Advisory Alert - FAC-003-3 MVCD
[7] Electric Power Research Institute. *Supplemental Testing to Confirm or Refine Gap Factor Utilized in Calculation of Minimum Vegetation Clearance Distances (MVCD).* 1-1. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002006527

Individuals who have facilitation skills and experience and/or legal or technical writing backgrounds are also strongly desired. Please include this in the description of qualifications as applicable.

Please provide the following information for the nominee:	
Name:	
Title:	
Organization:	
Address:	
Telephone:	
Email:	
Select the Project(s) for which the nominee is volunteering. Nominees may check multiple projects but NERC will endeavor to place an individual on only one project if at all possible. If checking multiple projects, indicate in the space below first choice, second choice, and so on. ☐ Project 2010-07.1 Vegetation Management FAC-003	
Please briefly describe the nominee's experience and qualifications to serve on the selected project(s):	
If you are currently a member of any NERC SAR or standard drafting team, please list each team here: ☐ Not currently on any active SAR or standard drafting team. ☐ Currently a member of the following SAR or standard drafting team(s):	
If you previously worked on any NERC SAR or standard drafting team, please identify the team(s): ☐ No prior NERC SAR or standard drafting team. ☐ Prior experience on the following SAR or standard drafting team(s):	
Select each NERC Region in which you have experience relevant to Project 2010-07.1:	

☐ ERCOT ☐ FRCC ☐ MRO	☐ NPCC ☐ RF ☐ SERC	☐ SPP ☐ WECC ☐ NA – Not Applicable

Select each Industry Segment that you represent:	
☐	1 — Transmission Owners
☐	2 — RTOs, ISOs
☐	3 — Load-serving Entities
☐	4 — Transmission-dependent Utilities
☐	5 — Electric Generators
☐	6 — Electricity Brokers, Aggregators, and Marketers
☐	7 — Large Electricity End Users
☐	8 — Small Electricity End Users
☐	9 — Federal, State, and Provincial Regulatory or other Government Entities
☐	10 — Regional Reliability Organizations and Regional Entities
☐	NA – Not Applicable

Select each Function[8] in which you have current or prior expertise:	
☐ Balancing Authority	☐ Transmission Operator
☐ Compliance Enforcement Authority	☐ Transmission Owner
☐ Distribution Provider	☐ Transmission Planner
☐ Generator Operator	☐ Transmission Service Provider
☐ Generator Owner	☐ Purchasing-selling Entity
☐ Interchange Authority	☐ Reliability Coordinator
☐ Load-serving Entity	☐ Reliability Assurer
☐ Market Operator	☐ Resource Planner
☐ Planning Coordinator	

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group:

[8] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

Name:		Telephone:	
Organization:		Email:	
Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group:			
Name:		Telephone:	
Organization:		Email:	
Provide the names and contact information of your immediate supervisor or a member of your management who can confirm your organization's willingness to support your active participation.			
Name:		Telephone:	
Title:		Email:	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2010-07.1 Vegetation Management

Standard Drafting Team Nomination Period Open through September 8, 2015

Now Available

Nominations are being sought for standard drafting team (SDT) members through **8 p.m. Eastern, Tuesday, September 8, 2015.**

Use the electronic form to submit a nomination. If you experience any difficulty using the electronic form, contact Nasheema Santos. An unofficial Word version of the nomination form is posted on the Standard Drafting Team Vacancies page and the project page.

By submitting a nomination form, you are indicating your willingness and agreement to participate in the SDT face-to-face meetings and conference calls.

The time commitment for this project is expected to be an average of two face-to-face meetings per quarter (typically two full working days each meeting) with conference calls scheduled as needed to meet the agreed upon timeline the SDT sets forth. SDT members also will have side projects, either individually or by subgroup, to present to the entire SDT for discussion and review. Lastly, an important component of the SDT effort is outreach. Members of the SDT will be expected to conduct industry outreach during the development process to support a successful ballot.

Previous SDT experience is beneficial but not required.

Project 2010-07.1 Vegetation Management
NERC retained the Electric Power Research Institute (EPRI) to conduct testing as directed in Order No. 777 to support appropriate Minimum Vegetation Clearance Distances (MVCDs) specified in NERC Reliability Standard FAC-003-3. The MVCDs in the Standard are calculated based on application of the Gallet equation which incorporates a gap factor. The test result findings determined the Gallet equation required changing from 1.3 to 1.0, which would increase the MVCD values compared to those specified in the existing standard.

Next Steps
The Standards Committee is expected to appoint members to the SDT in September 2015. Nominees will be notified shortly after they have been appointed to the SDT**.**

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Jordan Mallory (via email) or at (404) 446-2733.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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Standards Authorization Request Form

When completed, email this form to:
Barbara.Nutter@nerc.net

For questions about this form or for assistance in completing the form, call Barb Nutter at 404-446-9692.

NERC welcomes suggestions for improving the reliability of the Bulk-Power System through improved Reliability Standards. Please use this form to submit your proposal for a new NERC Reliability Standard or a revision to an existing standard.

Request to propose a new or a revision to a Reliability Standard			
Proposed Standard:	FAC-003-4		
Date Submitted:	August 19, 2015		
SAR Requester Information			
Name:	Minimum Vegetation Clearance Distances (MVCD) Advisory Group [Ron Adams]		
Organization:	Duke Energy		
Telephone:	(704) 382-7338	E-mail:	Ron.adams@duke-energy.com
SAR Type (Check as many as applicable)			
☐ New Standard ☒ Revision to existing Standard		☐ Withdrawal of existing Standard ☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
Correct the Gallet equation gap factors to reflect new information from Electric Power Research Institute (EPRI) study.
Purpose or Goal (How does this request propose to address the problem described above?):
The primary goal of this SAR is to address the findings of the EPRI report in the FAC-003 Reliability Standard.

SAR Information
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
Provide the appropriate minimum vegetation clearances distances within the FAC-003 standard.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The SDT shall modify FAC-003-3 to reflect the findings of the EPRI study.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
At the time the FAC-003-3 Reliability Standard was filed there was some question regarding the gap factors contained in the Gallet equation. To validate the gap factors, NERC contracted with EPRI to complete further studies. The preliminary report indicates the need for a modification to the gap factors. The drafting team will be modifying the standard based on the final report, which is scheduled to be released in July 2015.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☐ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.

Reliability Functions		
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☒	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
N/A	

Related Standards	

Related SARs	
SAR ID	Explanation
N/A	N/A

Regional Variances	
Region	Explanation
ERCOT	N/A
FRCC	N/A
MRO	N/A
NPCC	N/A
RFC	N/A
SERC	N/A
SPP	N/A
WECC	N/A

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

Project 2010-07.1 Vegetation Management – FAC-003

DO NOT use this form for submitting comments. Use the electronic form to submit comments on the Standard Authorization Request (SAR) by **8:00 p.m. Eastern, Monday, September 28, 2015**.

Documents and information about this project are available on the project page. If you have questions, contact Jordan Mallory (via email) or at 404-446-9733.

Background Information

This posting is soliciting informal comment on the SAR.

The purpose of the proposed project is to address the findings of the Electric Power Research Institute (EPRI) report, which was a part of the Federal Energy Regulatory Commission (FERC) Order No. 777[1] directive.

In Order No. 777, the FERC directed NERC to provide empirical data validating the gap factor for flashover distances between conductors and vegetation used in the Gallet equation to calculate Minimum Vegetation Clearance Distances (MVCDs) in NERC Reliability Standard FAC-003-2. In the order, FERC directed NERC to submit: (1) a schedule for testing; (2) the scope of work; (3) funding solutions; and (4) a deadline for submitting a final report on the test results to FERC, along with interim reports if a multiyear study is conducted.[2] NERC contracted the EPRI and performed a collaborative research project to complete the work. NERC submitted a compliance filing on July 12, 2013,[3] which FERC accepted on September 4, 2013.[4]

In January 2014, NERC formed an advisory group to develop the scope of work for the project. This team of subject matter experts assisted in developing the test plan, which included monitoring the testing and analyzing the test results to be provided in a final report. The advisory team was comprised of NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulator characteristics, and vegetation management. The project's scope of work and the detailed test plan were finalized in March 2014.

The testing project commenced in April 2014 and continued through October 2014. EPRI completed the prescribed tests to validate the gap factor applied in the Gallet equation. NERC filed an informational filing with FERC on July 31, 2014,[5] that contained the results of the testing work completed to date. The initial analysis, containing preliminary conclusions and recommendations, concluded in early 2015. Based on the

[1] *Revisions to Reliability Standard for Transmission Vegetation Management*, Order No. 777, 142 FERC ¶ 61,208 (2013).
[2] *Id*. at P 61.
[3] Compliance Filing of NERC, Docket No. RM12-4-000 (Jul. 12, 2013).
[4] *N. Am. Elec. Reliability Corp.*, Docket No. RM12-4-001 (Sept. 4, 2013) (delegated letter order).
[5] Informational Filing of NERC, Docket Nos. RM12-4-000 and RM12-4-001 (Jul. 31, 2014).

preliminary results, the gap factor used in the Gallet equation required modification from 1.3 to 1.0, which would increase the MVCD values compared to those specified in the existing standard.

NERC, through EPRI, performed additional tests in 2015 to finalize the gap-factor verification, communicate the research findings to industry through webinars and committee meetings, and issued an industry advisory alert in May 2015.[6] Final testing was completed and an EPRI report was posted on July 21, 2015. The report determined "that the proposed minimum vegetation clearance distances (MVCD), based on a gap factor of 1.3, should be increased and the corresponding gap factor reduced to a more conservative value of 1.0."[7]

Questions

1. Do you agree that the scope and objectives of the SAR? If not, please explain why you do not agree and, if possible, provide specific language revisions that would make it acceptable to you.

☐ Yes
☐ No
Comments:

If you have any other comments on this SAR that you haven't already mentioned above, please provide them here:
Comments:

[6] Industry Advisory Alert - FAC-003-3 MVCD
[7] Electric Power Research Institute. *Supplemental Testing to Confirm or Refine Gap Factor Utilized in Calculation of Minimum Vegetation Clearance Distances (MVCD).* 1-1. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002006527

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Standards Announcement

Project 2010-07.1 Vegetation Management Standard Authorization Request

Informal Comment Period Open through September 28, 2015

Now Available

A 30-day informal comment period for the **Project 2010-07.1 Vegetation Management** Standard Authorization Request (SAR) is open through **8 p.m. Eastern, Monday, September 28, 2015**.

Commenting
Use the electronic form to submit comments on the SAR. If you experience any difficulties in using the electronic form, contact Nasheema Santos. An unofficial Word version of the comment form is posted on the project page.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Jordan Mallory (via email) or at (404) 446-2733.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Survey Report

Survey Details

Name 2010-07.1 Vegetation Management | FAC-003-3 SAR

Description

Start Date 8/24/2015

End Date 9/28/2015

Associated Ballots

Survey Questions

1. Do you agree that the scope and objectives of the SAR? If not, please explain why you do not agree and, if possible, provide specific language revisions that would make it acceptable to you.

Yes

No

If you have any other comments on this SAR that you haven't already mentioned above, please provide them here:

Responses By Question

1. Do you agree that the scope and objectives of the SAR? If not, please explain why you do not agree and, if possible, provide specific language revisions that would make it acceptable to you.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tammy Porter - Oncor Electric Delivery - 1 - TRE

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michelle Amarantos - APS - Arizona Public Service Co. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6

Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Voter Information

Voter	Segment
Emily Rousseau	1,2,3,4,5,6
Entity	**Region(s)**
MRO	MRO

Selected Answer: Yes

Answer Comment: The NSRF agrees with the SAR to update Table 2 MVCD's with the EPRI findings.

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Information

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Voter Information

Voter

Randi Heise

Segment

5

Entity

Dominion - Dominion Resources, Inc.

Region(s)

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Information

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Voter Information

Voter

Colby Bellville

Segment

1,3,5,6

Entity

Duke Energy

Region(s)

FRCC,SERC,RFC

Selected Answer: Yes

Answer Comment:

Duke Energy agrees with the scope and objectives of the SAR which appear to align MVCD with the empirical data stemming from the EPRI study.

Document Name:

Likes: 0

Dislikes: 0

Randall Hubbard - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - FRCC,WECC,TRE,SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc..	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R. Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Voter Information

Voter

Randall Hubbard

Segment

1,3,5,6

Entity

Southern Company - Southern Company Services, Inc.

Region(s)

FRCC,WECC,TRE,SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2010-07.1 Vegetation Management - FAC-003-3

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5

Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Voter Information

Voter	Segment
Lee Pedowicz	10
Entity	**Region(s)**
Northeast Power Coordinating Council	NPCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
Robert Hirchak	Cleco Corporation	SPP	1,3,5,6
Tara Lightner	Sunflower Electric Power Corporation	SPP	1
Bruce Dooley	Sunflower Electric Power Corporation	SPP	1
Kevin Giles	Westar Energy, Inc	SPP	1,3,5,6
James Nail	City of Independence, Missouri	SPP	3,5

Voter Information

Voter	Segment
Shannon Mickens	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer: Yes

Answer Comment:

We agree with the scope and objective of the SAR. However, we would suggest to the drafting team to conduct a thorough evaluation of how the Gallet Equation was used in the previous calculation of the Minimum Vegetation Clearance Distance (MVCD) and current EPRI Study. We feel this evaluation will help develop a structural value for FAC-003 and ensure all concerns have been addressed in reference to the previous and future calculations for the gap factor.

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter	Segment
Richard Hoag	1,3,4,5,6
Entity	**Region(s)**
FirstEnergy - FirstEnergy Corporation	RFC

Selected Answer: Yes

Answer Comment:

Yes, FE Energy Delivery -Transmission Vegetation Management agrees with the scope and objectives of the SAR.
As a result of testing conducted by EPRI, at NERC's request, the MVCD listed in Standard FAC-003-3 required to prevent a flashover and improve the reliability of the Bulk Power System (BPS) will need to be increased. The EPRI report determined “that the proposed minimum vegetation clearance distances (MVCD), based on a gap factor of 1.3, should be increased and the corresponding gap factor reduced to a more conservative value of 1.0.” TVM clearances far exceed the new MVCD Table distances, therefore no objections or comments are necessary.

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ben Engelby - ACES Power Marketing - 6 -

Group Information

Group Name: ACES Standards Collaborators - FAC-003 Project

Group Member Name	Entity	Region	Segments
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
Amber Skillern	East Kentucky Power Cooperative	SERC	1,3
Ginger Mercier	Prairie Power Inc.	SERC	1,3
Mohan Sachdeva	Buckeye Power, Inc.	RFC	4
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1

Voter Information

Voter

Ben Engelby

Segment

6

Entity

ACES Power Marketing

Region(s)

Selected Answer: Yes

Answer Comment:

We support the changes to FAC-003, as they are aligned with the directives in FERC Order No. 777.

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

If you have any other comments on this SAR that you haven't already mentioned above, please provide them here:

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tammy Porter - Oncor Electric Delivery - 1 - TRE

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michelle Amarantos - APS - Arizona Public Service Co. - 1 -

Selected Answer:

Answer Comment:

APS agrees with the findings of the EPRI study and supports modifications to the gap factors of the Gallet equation.

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6

Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Voter Information

Voter	Segment
Emily Rousseau	1,2,3,4,5,6
Entity	**Region(s)**
MRO	MRO

Selected Answer:

Answer Comment: Limit the FAC-003-4 modifications to the Table 2 MVCD update, only.

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Information

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Voter Information

Voter

Randi Heise

Segment

5

Entity

Dominion - Dominion Resources, Inc.

Region(s)

Selected Answer:

Answer Comment:

Page 2 - under Detailed Description; Dominion suggests the last sentence which says; “The drafting team will be modifying the standard based on the final report, which is scheduled to be released in July 2015.” be updated to reflect when the final report was released (July 2015 has past).

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Information

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Voter Information

Voter

Colby Bellville

Segment

1,3,5,6

Entity

Duke Energy

Region(s)

FRCC,SERC,RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Randall Hubbard - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - FRCC,WECC,TRE,SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc..	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R. Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Voter Information

Voter

Randall Hubbard

Segment

1,3,5,6

Entity

Southern Company - Southern Company Services, Inc.

Region(s)

FRCC,WECC,TRE,SERC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2010-07.1 Vegetation Management - FAC-003-3

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5

Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Voter Information

Voter	Segment
Lee Pedowicz	10
Entity	**Region(s)**
Northeast Power Coordinating Council	NPCC

Selected Answer:

Answer Comment:

On page 2 of the SAR the last sentence under Detailed Description reads:

"The drafting team will be modifying the standard based on the final report, which is scheduled to be released in July 2015."

This sentence should be revised to reflect the actual release date of the final report (August 15, 2015 from the NERC Website).

NERC's May 14, 2015 Industry Advisory FAC-003-3 Minimum Vegetation Clearance Distances (MVCD) refers to "alternating current system voltages…" Was any testing done for high voltage DC voltages? The report apparently refers to only AC voltages. The SAR should stipulate this. What is the intention for addressing HVDC clearances?

The SAR should address a flexible Vegetation Control Cycle based on historic vegetation inspections from each area.

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
Robert Hirchak	Cleco Corporation	SPP	1,3,5,6
Tara Lightner	Sunflower Electric Power Corporation	SPP	1
Bruce Dooley	Sunflower Electric Power Corporation	SPP	1
Kevin Giles	Westar Energy, Inc	SPP	1,3,5,6
James Nail	City of Independence, Missouri	SPP	3,5

Voter Information

Voter	Segment
Shannon Mickens	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter	Segment
Richard Hoag	1,3,4,5,6
Entity	**Region(s)**
FirstEnergy - FirstEnergy Corporation	RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ben Engelby - ACES Power Marketing - 6 -

Group Information

Group Name: ACES Standards Collaborators - FAC-003 Project

Group Member Name	Entity	Region	Segments
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
Amber Skillern	East Kentucky Power Cooperative	SERC	1,3
Ginger Mercier	Prairie Power Inc.	SERC	1,3
Mohan Sachdeva	Buckeye Power, Inc.	RFC	4
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1

Voter Information

Voter

Ben Engelby

Segment

6

Entity

ACES Power Marketing

Region(s)

Selected Answer:

Answer Comment:

We would appreciate guidance regarding compliance with Table 2 in the interim while the proposed revisions of this SAR go through the development process and eventually approved by FERC and becomes enforceable. FAC-003-2 requires that the MVCDs utilize a gap factor of 1.3, which is the current enforceable standard. Is there going to be a change in compliance monitoring approaches prior to the issuance of FAC-003-4? Any additional information relating to the NERC Advisory and how it relates to compliance with the standard would be helpful.

Thank you for the opportunity to comment.

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Consideration of Comments

Project Name: 2010-07.1 Vegetation Management

Comment Period Start Date: 8/24/2015

Comment Period End Date: 9/28/2015

There were 24 sets of responses, including comments from approximately 18 different people from approximately 18 different companies representing 7 of the 10 Industry Segments as shown on the following pages.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Howard Gugel (via email) or at (404) 446-9693.

Questions

1. **Do you agree that the scope and objectives of the SAR? If not, please explain why you do not agree and, if possible, provide specific language revisions that would make it acceptable to you.**
2. **If you have any other comments on this SAR that you haven't already mentioned above, please provide them here:**

The Industry Segments are:

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

1. Do you agree that the scope and objectives of the SAR? If not, please explain why you do not agree and, if possible, provide specific language revisions that would make it acceptable to you.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Tammy Porter - Oncor Electric Delivery - 1 - TRE

Selected Answer: Yes

Michelle Amarantos - APS - Arizona Public Service Co. - 1 -

Selected Answer: Yes

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc.	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6

Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Selected Answer: Yes

Answer Comment: The NSRF agrees with the SAR to update Table 2 MVCD's with the EPRI findings.

Response: Thank you.

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: Yes

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Selected Answer: Yes

Answer Comment:

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Selected Answer: Yes

Answer Comment: **Duke Energy agrees with the scope and objectives of the SAR which appear to align MVCD with the empirical data stemming from the EPRI study.**

Response: Thank you.

Randall Hubbard - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - FRCC,WECC,TRE,SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc.	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R. Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Selected Answer: Yes

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2010-07.1 Vegetation Management - FAC-003-3

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1

Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Selected Answer: Yes

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
Robert Hirchak	Cleco Corporation	SPP	1,3,5,6
Tara Lightner	Sunflower Electric Power Corporation	SPP	1
Bruce Dooley	Sunflower Electric Power Corporation	SPP	1
Kevin Giles	Westar Energy, Inc	SPP	1,3,5,6
James Nail	City of Independence, Missouri	SPP	3,5

Selected Answer: Yes

Answer Comment: We agree with the scope and objective of the SAR. However, we would suggest to the drafting team to conduct a thorough evaluation of how the Gallet Equation was used in the previous calculation of the Minimum Vegetation Clearance Distance (MVCD) and current EPRI Study. We feel this evaluation will help develop a structural value for FAC-003 and ensure all concerns have been addressed in reference to the previous and future calculations for the gap factor.

Response: Thank you for your comment. The proposed standard is consistent with FERC Order No. 777, which states: “As we [FERC] stated in the NOPR, and adopt in the Final Rule, the application of the Gallet equation appears to be one reasonable method to calculate MVCD values.”

Please reference the EPRI report filed on August 12, 2015 in FERC Docket No. RM12-4 (link) and the current FAC-003-3 Guideline and Technical Basis section for the MVCD of the FAC-003-3 standard for further information.

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer: Yes

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Selected Answer: Yes

Answer Comment: Yes, FE Energy Delivery -Transmission Vegetation Management agrees with the scope and objectives of the SAR.

As a result of testing conducted by EPRI, at NERC's request, the MVCD listed in Standard FAC-003-3 required to prevent a flashover and improve the reliability of the Bulk Power System (BPS) will need to be increased. The EPRI report determined “that the proposed minimum vegetation clearance distances (MVCD), based on a gap factor of 1.3, should be increased and the corresponding gap factor reduced to a more conservative value of 1.0.” TVM clearances far exceed the new MVCD Table distances, therefore no objections or comments are necessary.

Response: Thank you.

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Ben Engelby - ACES Power Marketing - 6 -

Group Name: ACES Standards Collaborators - FAC-003 Project

Group Member Name	Entity	Region	Segments
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
Amber Skillern	East Kentucky Power Cooperative	SERC	1,3
Ginger Mercier	Prairie Power Inc.	SERC	1,3
Mohan Sachdeva	Buckeye Power, Inc.	RFC	4
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1

Selected Answer: Yes

Answer Comment: We support the changes to FAC-003, as they are aligned with the directives in FERC Order No. 777.

Response: Thank you.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

2. If you have any other comments on this SAR that you haven't already mentioned above, please provide them here:

Michelle Amarantos - APS - Arizona Public Service Co. - 1 -

Answer Comment: APS agrees with the findings of the EPRI study and supports modifications to the gap factors of the Gallet equation.

Response: Thank you.

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Answer Comment: Limit the FAC-003-4 modifications to the Table 2 MVCD update, only.

Response: Thank you. The SDT felt it appropriate to make other, non-substantive changes to the document that do not have an impact to the meaning of the standard.

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Answer Comment: Page 2 - under Detailed Description; Dominion suggests the last sentence which says; "The drafting team will be modifying the standard based on the final report, which is scheduled to be released in July 2015." be updated to reflect when the final report was released (July 2015 has past).

Response: Thank you. The SAR will be updated to reflect the final report publishing date. Click here for: The final EPRI Report, which was published on July 21, 2015.

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2010-07.1 Vegetation Management - FAC-003-3

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10

David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Answer Comment:

On page 2 of the SAR the last sentence under Detailed Description reads:

"The drafting team will be modifying the standard based on the final report, which is scheduled to be released in July 2015."

This sentence should be revised to reflect the actual release date of the final report (August 15, 2015 from the NERC Website).

NERC's May 14, 2015 Industry Advisory FAC-003-3 Minimum Vegetation Clearance Distances (MVCD) refers to "alternating current system voltages…" Was any testing done for high voltage DC voltages? The report apparently refers to only AC voltages. The SAR should stipulate this. What is the intention for addressing HVDC clearances?

The SAR should address a flexible Vegetation Control Cycle based on historic vegetation inspections from each area.

Response: Thank you. The SAR has been updated to reflect the final report publishing date. Click here for: The final EPRI Report, which was published on July 21, 2015.

The scope of the EPRI study did not include DC voltages. To-date there have been no stakeholder concerns associated with the MVCD for DC. Thus there is no intention to test DC values. The scope of the project also does not include addressing a flexible vegetation control cycle.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
Robert Hirchak	Cleco Corporation	SPP	1,3,5,6
Tara Lightner	Sunflower Electric Power Corporation	SPP	1
Bruce Dooley	Sunflower Electric Power Corporation	SPP	1
Kevin Giles	Westar Energy, Inc	SPP	1,3,5,6
James Nail	City of Independence, Missouri	SPP	3,5

Ben Engelby - ACES Power Marketing - 6 -

Group Name: ACES Standards Collaborators - FAC-003 Project

Group Member Name	Entity	Region	Segments
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
Amber Skillern	East Kentucky Power Cooperative	SERC	1,3
Ginger Mercier	Prairie Power Inc.	SERC	1,3
Mohan Sachdeva	Buckeye Power, Inc.	RFC	4
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1

Answer Comment:

We would appreciate guidance regarding compliance with Table 2 in the interim while the proposed revisions of this SAR go through the development process and eventually approved by FERC and becomes enforceable. FAC-003-2 requires that the MVCDs utilize a gap factor of 1.3, which is the current enforceable standard. Is there going to be a change in compliance monitoring approaches prior to the issuance of FAC-003-4? Any additional information relating to the NERC Advisory and how it relates to compliance with the standard would be helpful.

Thank you for the opportunity to comment.

Response: Thank you. This comment is beyond the scope of the drafting team. Please see the industry advisory FAC-003-3 Minimum Vegetation Clearance Distances (MVCD), which was distributed on May 14, 2015.

End of Report

Standard Development Timeline

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

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	August 19, 2015
SAR posted for comment	August 24, 2015

Anticipated Actions	Date
45-day formal comment period with ballot	October 2015
10-day final ballot	January 2016
NERC Board (Board) adoption	February 2016

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Transmission Vegetation Management

2. **Number:** FAC-003-4

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

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Applicable Transmission Owners

   4.1.1.1. Transmission Owners that own Transmission Facilities defined in 4.2.

   4.1.2. Applicable Generator Owners

   4.1.2.1. Generator Owners that own generation Facilities defined in 4.3

   4.2. Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[1], 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 Authority.

   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

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies."*

4.3. Generation Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[2], state, provincial, public, private, or tribal entities:

4.3.1. Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) do not have a clear line of sight[3] from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and are:

4.3.1.1. Operated at 200kV or higher; or

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

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

5. **Effective Date:** See Implementation Plan.

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

a) Performance-based defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system <u>performance result or outcome</u>?*

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 <u>reduces a stated risk</u> 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 <u>what capability</u>, 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

[2] *Id.*

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

should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.

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

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

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

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

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

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

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

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

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

B. Requirements and Measures

R1. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below[4] *[Violation Risk Factor: High] [Time Horizon: Real-time]*

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

1.1 An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,[5]

1.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[6]

1.3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[7],

1.4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.[8]

M1. Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

R2. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[9] *[Violation Risk Factor: High] [Time Horizon: Real-time]*

2.1. An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage,[10]

2.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[11]

2.3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,[12]

2.4. An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage.[13]

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

[6] 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.

[7] *Id.*

[8] *Id.*

[9] See footnote 4.

[10] See footnote 5.

[11] See footnote 6.

[12] *Id.*

[13] *Id.*

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

R3. Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

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.

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

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

M4. Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

R5. When a applicable Transmission Owner and applicable Generator Owner is constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to

prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M5. Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

R6. Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW[14] [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M6. Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

R7. Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

7.1. Change in expected growth rate/environmental factors

7.2. Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner[15]

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

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

7.3. Rescheduling work between growing seasons

7.4. Crew or contractor availability/Mutual assistance agreements

7.5. Identified unanticipated high priority work

7.6. Weather conditions/Accessibility

7.7. Permitting delays

7.8. Land ownership changes/Change in land use by the landowner

7.9. Emerging technologies

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

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

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

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

- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, for three calendar years.
- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless

directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

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

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information

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

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

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

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

- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

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

Violation Severity Levels (Table 1)

R #	Table 1: Violation Severity Levels (VSL)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following: • *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.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and a

			transfer path and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	vegetation-related Sustained Outage was caused by one of the following: • *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*
R3.		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity's applicable lines. (Requirement R3, Part 3.2)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines. Requirement R3, Part 3.1)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity's applicable lines.
R4.			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority	The responsible entity experienced a confirmed vegetation threat and did not notify the control center

			for that applicable line, but there was intentional delay in that notification.	holding switching authority for that applicable line.
R5.				The responsible entity did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6.	The responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7.	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Variances

None.

E. Associated Documents

- Link to FAC-003-4 Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	January 20, 2006	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.	New
1	April 4, 2007	Regulatory Approval - Effective Date	New
2	November 3, 2011	Adopted by the NERC Board of Trustees	New
2	March 21, 2013	FERC Order issued approving FAC-003-2 (Order No. 777) FERC Order No. 777 was issued on March 21, 2013 directing NERC to "conduct or contract testing to obtain empirical data and submit a report to the Commission providing the results of the testing."[16]	Revisions
2	May 9, 2013	Board of Trustees adopted the	Revisions

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

		modification of the VRF for Requirement R2 of FAC-003-2 by raising the VRF from "Medium" to "High."	
3	May 9, 2013	FAC-003-3 adopted by Board of Trustees	Revisions
3	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-003-3. This standard becomes enforceable on July 1, 2014 for Transmission Owners. For Generator Owners, R3 becomes enforceable on January 1, 2015 and all other requirements (R1, R2, R4, R5, R6, and R7) will become enforceable on January 1, 2016.	Revisions
3	November 22, 2013	Updated the VRF for R2 from "Medium" to "High" per a Final Rule issued by FERC	Revisions
3	July 30, 2014	Transferred the effective dates section from FAC-003-2 (for Transmission Owners) into FAC-003-3, per the FAC-003-3 implementation plan	Revisions
4	Projected initial posting October 2015	Adjusted MVCD values in Table 2 for alternating current systems, consistent with findings reported in report filed on August 12, 2015 in Docket No. RM12-4-002 consistent with FERC's directive in Order No. 777, and based on empirical testing results for flashover distances between conductors and vegetation.	Revisions

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[17]

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)+	(AC) Maximum System Voltage (kV)[18]	MVCD (feet) Over sea level up to 500 ft	MVCD (feet) Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft	MVCD feet Over 11000 ft up to 12000 ft	MVCD feet Over 12000 ft up to 13000 ft	MVCD feet Over 14000 ft up to 15000 ft
765	800	11.6ft	11.7ft	11.9ft	12.1ft	12.2ft	12.4ft	12.6ft	12.8ft	13.0ft	13.1ft	13.3ft	13.5ft	13.7ft	13.9ft	14.0ft
500	550	7.0ft	7.1ft	7.2ft	7.4ft	7.5ft	7.6ft	7.8ft	7.9ft	8.1ft	8.2ft	8.3ft	8.5ft	8.6ft	8.8ft	8.9ft
345	362	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft
287	302	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft	5.8ft	5.9ft	6.1ft	6.2ft	6.3ft	6.4ft	6.5ft	6.6ft	6.7ft
230	242	4.0ft	4.1ft	4.2t	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft
161*	169	2.7ft	2.7ft	2.8ft	2.9ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft	3.3ft	3.3ft	3.4ft	3.5ft	3.6ft	3.6ft
138*	145	2.3ft	2.3ft	2.4ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft	2.7ft	2.8ft	2.8ft	2.9ft	3.0ft	3.0ft	3.1ft
115*	121	1.9ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.1ft	2.2ft	2.2ft	2.3ft	2.3ft	2.4ft	2.5ft	2.5ft	2.6ft
88*	100	1.5ft	1.5ft	1.6ft	1.6ft	1.7ft	1.7ft	1.8ft	1.8ft	1.8ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.1ft
69*	72	1.1ft	1.1ft	1.1ft	1.2ft	1.2ft	1.2ft	1.2ft	1.3ft	1.3ft	1.3ft	1.4ft	1.4ft	1.4ft	1.5ft	1.5ft

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

+ *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the NERC Advisory posted on May 14, 2015.*

[17] 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.

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

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[19]

For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)+	(AC) Maximum System Voltage (kV)[20]	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	MVCD meters Over 3353m up to 3657m	MVCD meters Over 3657m up to 3962m	MVCD meters Over 3692m up to 4267m
765	800	3.6m	3.6m	3.6m	3.7m	3.7m	3.8m	3.8m	3.9m	4.0m	4.0m	4.1m	4.1m	4.2m	4.2m	4.3m
500	550	2.1m	2.2m	2.2m	2.3m	2.3m	2.3m	2.4m	2.4m	2.5m	2..5m	2.5m	2.6m	2.6m	2.7m	2.7m
345	362	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	.5m	1.6m	1.6m	1.6m	1.6m	1.7m	1.7m
287	302	1.6m	1.6m	1.7m	1.7m	1.7m	1.7m	1.8m	1.8m	1.9m	1.9m	1.9m	2.0m	2.0m	2.0m	2.1m
230	242	1.2m	1.3m	1.3m	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m
161*	169	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m	1.0m	1.0m	1.0m	1.1m	1.1m	1.1m
138*	145	0.7m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	0.9m
115*	121	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	.07m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m
88*	100	0.4m	0.4m	0.5m	0.5m	0.5m	0.5m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m
69*	72	0.3m	0.3m	0.3m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.5m	0.5m

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

+ *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the NERC Advisory posted on May 14, 2015.*

[19] 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.

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

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[21]

For **Direct Current** Voltages feet (meters)

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

[21] 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.

Guideline and Technical Basis

Effective dates:

The Compliance section is standard language used in most NERC standards to cover the general effective date and covers the vast majority of situations. A special case covers effective dates for (1) lines initially becoming subject to the Standard, (2) lines changing in applicability within the standard.

The special case is needed because the Planning Authorities 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 Authority in 2015 may identify a line to have that designation beginning in PY 2025, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. 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.

Date that Planning Study is completed	PY the line will become an IROL element	Date 1	Date 2	Effective Date The latter of Date 1 or Date 2
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

Defined Terms:

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

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

Explanation of the derivation 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. The table is based on empirical testing data from EPRI as requested by FERC in Order No. 777.

Project 2010-07.1 Adjusted MVCDs per EPRI Testing:
In Order No. 777, FERC directed NERC to undertake testing to gather empirical data validating the appropriate gap factor used in the Gallet equation to calculate MVCDs, specifically the gap factor for the flash-over distances between conductors and vegetation. See, Order No. 777, at P 60. NERC engaged industry through a collaborative research project and contracted EPRI to complete the scope of work. In January 2014, NERC formed an advisory group to assist with developing the scope of work for the project. This team provided subject matter expertise for developing the test plan, monitoring testing, and vetting the analysis and conclusions to be submitted in a final report. The advisory team comprised NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulation coordination, and vegetation management. The testing project commenced in April 2014 and continued through October 2014 with the final set of testing completed in May 2015. Based on these testing results conducted by EPRI, and consistent with the report filed in FERC Docket No. RM12-4-000, the gap factor used in the Gallet equation require adjustment from 1.3 to 1.0. This resulted in increased MVCD values for all alternating current system voltages identified. The adjusted MVCD values, reflecting the 1.0 gap factor, are included in Table 2 of version 4 of FAC-003.

The air gap testing completed by EPRI per FERC Order No. 777 established that trees with large spreading canopies growing directly below energized high voltage conductors create the

greatest likelihood of an air gap flash over incident and was a key driver in changing the gap factor to a more conservative value of 1.0 in version 4 of this standard.

Requirements R1 and R2:

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

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant.

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.

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

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

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner

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

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

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

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

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

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

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*

2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

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

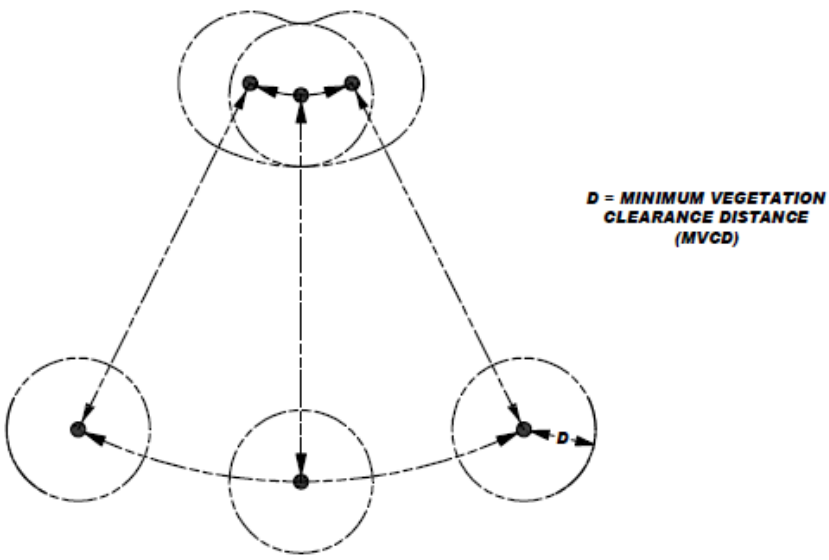

Figure 1

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

Requirement R4:

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

authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

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

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

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

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

Requirement R5:

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

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

applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

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

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

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

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

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once

during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. The "Low VSL" for R6 would apply in this example.

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

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

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

In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner's or applicable Generator Owner's easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces

the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

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

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

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.

Since no empirical data for spark over distances to live vegetation existed at the time version 3 was developed, the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

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

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

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

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

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

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

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

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

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

Rationale for R3:
The documentation provides a basis for evaluating the competency of the applicable Transmission Owner's or applicable Generator Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions.

Rationale for R4:
This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

Rationale for R5:
Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

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

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

Rationale for R6:
Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

Rationale for R7:
This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

Standard Development Timeline

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

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	August 19, 2015
SAR posted for comment	August 24, 2015

Anticipated Actions	Date
45-day formal comment period with ballot	October 2015
10-day final ballot	January 2016
NERC Board (Board) adoption	February 2016

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Transmission Vegetation Management

2. **Number:** FAC-003-4~~3~~

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

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Applicable Transmission Owners

   4.1.1.1. Transmission Owners that own Transmission Facilities defined in 4.2.

   4.1.2. Applicable Generator Owners

   4.1.2.1. Generator Owners that own generation Facilities defined in 4.3

   4.2. Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[1], 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~~ Authority.

   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

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies."*

4.3. Generation Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[2], state, provincial, public, private, or tribal entities:

4.3.1. Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) do not have a clear line of sight[3] from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and are:

4.3.1.1. Operated at 200kV or higher; or

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

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

~~**5.**~~ **Effective Date:** See Implementation Plan. ~~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.~~

~~**6.** 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.~~

~~**7.** Entities must comply with the "Compliance" section in its entirety, including the Administrative Procedure that sets forth, among other things, reporting requirements.~~

~~**8.**~~**5.** ~~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~~

[2] *Id.*

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

~~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~~

~~**Generator Owners**~~

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

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

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

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

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

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

1. ~~A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.~~

~~2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.~~

~~3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.~~

~~4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.~~

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

~~**Transmission Owners** [transferred from FAC-003-2]~~

~~This standard becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval is required. Where no regulatory approval is required, the standard becomes effective on the first calendar day of the first calendar quarter one year after Board of Trustees adoption.~~

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

~~1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC transfer Path.~~

~~2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.~~

~~3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.~~

~~4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard, becomes subject to this standard 12 months after the acquisition date.~~

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

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

a) Performance-based defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome?*

b) Risk-based preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?*

c) Competency-based defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?*

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

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

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the

interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);

- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

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

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

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

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

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

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

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

B. Requirements and Measures

R1. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below[4] *[Violation Risk Factor: High] [Time Horizon: Real-time]*

1.1 An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,[5]

1.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[6]

1.3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[7],

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

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

[6] 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.

[7] *Id.*

1.4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.[8]

M1. Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

R2. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[9] *[Violation Risk Factor: High] [Time Horizon: Real-time]*

2.1. An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage,[10]

2.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[11]

2.3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,[12]

2.4. An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage.[13]

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

R3. Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

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[8] *Id.*
[9] See footnote 4.
[10] See footnote 5.
[11] See footnote 6.
[12] *Id.*

[13] *Id.*

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.

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

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

M4. Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

R5. When a applicable Transmission Owner and applicable Generator Owner is constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M5. Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

R6. Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar

year and with no more than 18 calendar months between inspections on the same ROW[14] [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M6. Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

R7. Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

7.1. Change in expected growth rate/environmental factors

7.2. Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner[15]

7.3. Rescheduling work between growing seasons

7.4. Crew or contractor availability/Mutual assistance agreements

7.5. Identified unanticipated high priority work

7.6. Weather conditions/Accessibility

7.7. Permitting delays

7.8. Land ownership changes/Change in land use by the landowner

7.9. Emerging technologies

7.10. Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the

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

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

completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

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

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

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

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

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

- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, for three calendar years.~~Measures M1, M2, M3, M5, M6 and M7 for three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.~~
- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- If a applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-

compliance until found compliant or for the time period specified above, whichever is longer.

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

1.3. Compliance Monitoring and Enforcement Program

~~Compliance Audit~~

~~Self-Certification~~

~~Spot Checking~~

~~Compliance Violation Investigation~~

~~Self-Reporting~~

~~Complaint~~

~~Periodic Data Submittal~~

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information

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

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

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

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;

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

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

Violation Severity Levels (Table 1)

R #	Table 1: Violation Severity Levels (VSL)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following: • *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.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and a

			transfer path and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	vegetation-related Sustained Outage was caused by one of the following: • *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*
R3.		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity's applicable lines. (Requirement R3, Part 3.2)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines. Requirement R3, Part 3.1)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity's applicable lines.
R4.			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority	The responsible entity experienced a confirmed vegetation threat and did not notify the control center

			for that applicable line, but there was intentional delay in that notification.	holding switching authority for that applicable line.
R5.				The responsible entity did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6.	The responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7.	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Variances

None.

~~E. Interpretations~~

~~None.~~

~~F.~~E. Associated Documents

- Link to FAC-003-4 Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	January 20, 2006	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.	New
1	April 4, 2007	Regulatory Approval - Effective Date	New
2	November 3, 2011	Adopted by the NERC Board of Trustees	New
2	March 21, 2013	FERC Order issued approving FAC-003-2 (Order No. 777) FERC Order No. 777 was issued on March 21, 2013 directing NERC to "conduct or contract testing to	Revisions

		obtain empirical data and submit a report to the Commission providing the results of the testing."[16]	
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."	Revisions
3	May 9, 20132	FAC-003-3 adopted by Board of Trustees	Revisions
3	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-003-3. This standard becomes enforceable on July 1, 2014 for Transmission Owners. For Generator Owners, R3 becomes enforceable on January 1, 2015 and all other requirements (R1, R2, R4, R5, R6, and R7) will become enforceable on January 1, 2016.	Revisions
3	November 22, 2013	Updated the VRF for R2 from "Medium" to "High" per a Final Rule issued by FERC	Revisions
3	July 30, 2014	Transferred the effective dates section from FAC-003-2 (for Transmission Owners) into FAC-003-3, per the FAC-003-3 implementation plan	Revisions
4	Projected initial posting October 2015	Adjusted MVCD values in Table 2 for alternating current systems, consistent with findings reported in report filed on August 12, 2015 in Docket No. RM12-4-002 consistent with FERC's directive in Order No. 777, and based on empirical testing results for	Revisions

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

		flashover distances between conductors and vegetation.	

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[17]

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)[+]	(AC) Maximum System Voltage (kV)[18]	MVCD (feet) Over sea level up to 500 ft	MVCD (feet) Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft	MVCD feet Over 11000 ft up to 12000 ft	MVCD feet Over 12000 ft up to 13000 ft	MVCD feet Over 14000 ft up to 15000 ft
765	800	~~8.2~~11.6ft	~~8.33~~11.7ft	~~8.61~~11.9ft	~~8.89~~12.1ft	~~9.17~~12.2ft	~~9.45~~12.4ft	~~9.73~~12.6ft	~~10.01~~12.8ft	~~10.29~~13.0ft	~~10.57~~13.1ft	~~10.85~~13.3ft	~~11.13~~13.5ft	13.7ft	13.9ft	14.0ft
500	550	7.0~~5.15~~ft	7.1~~5.25~~ft	~~5.45~~7.2ft	~~5.66~~7.4ft	~~5.86~~7.5ft	~~6.07~~7.6ft	~~6.28~~7.8ft	~~6.49~~7.9ft	~~6.7~~8.1ft	~~6.92~~8.2ft	8.3~~7.13~~ft	~~7.35~~8.5ft	8.6ft	8.8ft	8.9ft
345	362	~~3.19~~4.3ft	~~3.26~~4.3ft	~~3.39~~4.4ft	~~3.53~~4.5ft	~~3.67~~4.6ft	~~3.82~~4.7ft	~~3.97~~4.8ft	~~4.12~~4.9ft	~~4.27~~5.0ft	~~4.43~~5.1ft	~~4.58~~5.2ft	~~4.74~~5.3ft	5.4ft	5.5ft	5.6ft
287	302	~~3.88~~5.2ft	~~3.96~~5.3ft	~~4.12~~5.4ft	~~4.29~~5.5ft	~~4.45~~5.6ft	~~4.62~~5.7ft	~~4.79~~5.8ft	~~4.97~~5.9ft	~~5.14~~6.1ft	~~5.32~~6.2ft	~~5.50~~6.3ft	~~5.68~~6.4ft	6.5ft	6.6ft	6.7ft
230	242	~~3.03~~4.0ft	~~3.09~~4.1ft	~~3.22f~~4.2t	~~3.36~~4.3ft	~~3.49~~4.3ft	~~3.63~~4.4ft	~~3.78~~4.5ft	~~3.92~~4.6ft	~~4.07~~4.7ft	~~4.22~~4.8ft	~~4.37~~4.9ft	~~4.53~~5.0ft	5.1ft	5.2ft	5.3ft
161*	169	~~2.05~~2.7ft	~~2.09~~2.7ft	~~2.19~~2.8ft	~~2.28~~2.9ft	~~2.38~~2.9ft	~~2.48~~3.0ft	~~2.58~~3.0ft	~~2.69~~3.1ft	~~2.8~~3.2ft	~~2.91~~3.3ft	~~3.03~~3.3ft	~~3.14~~3.4ft	3.5ft	3.6ft	3.6ft
138*	145	~~1.74~~2.3ft	~~1.78~~2.3ft	~~1.86~~2.4ft	~~1.94~~2.4ft	~~2.03~~2.5ft	~~2.12~~2.5ft	~~2.21~~2.6ft	~~2.3~~2.7ft	~~2.4~~2.7ft	~~2.49~~2.8ft	~~2.59~~2.8ft	~~2.7~~2.9ft	3.0ft	3.0ft	3.1ft
115*	121	~~1.44~~1.9ft	~~1.47~~1.9ft	~~1.54~~1.9ft	~~1.61~~2.0ft	~~1.68~~2.0ft	~~1.75~~2.1ft	~~1.83~~2.1ft	~~1.91~~2.2ft	~~1.99~~2.2ft	~~2.07~~2.3ft	~~2.16~~2.3ft	~~2.25~~2.4ft	2.5ft	2.5ft	2.6ft
88*	100	~~1.18~~1.5ft	~~1.21~~1.5ft	~~1.26~~1.6ft	~~1.32~~1.6ft	~~1.38~~1.7ft	~~1.44~~1.7ft	~~1.5~~1.8ft	~~1.57~~1.8ft	~~1.64~~1.8ft	~~1.71~~1.9ft	~~1.78~~1.9ft	~~1.86~~2.0ft	2.0ft	2.1ft	2.1ft
69*	72	~~0.84~~1.1ft	~~0.86~~1.1ft	~~0.90~~1.1ft	~~0.94~~1.2ft	~~0.99~~1.2ft	~~1.03~~1.2ft	~~1.08~~1.2ft	~~1.13~~1.3ft	~~1.18~~1.3ft	~~1.23~~1.3ft	~~1.28~~1.4ft	~~1.34~~1.4ft	1.4ft	1.5ft	1.5ft

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

[+] *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the NERC Advisory posted on May 14, 2015.*

[17] 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.

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

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[19]

For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)[+]	(AC) Maximum System Voltage (kV)[8][20]	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	MVCD meters Over 3353m up to 3657m	MVCD meters Over 3657m up to 3962m	MVCD meters Over 3692m up to 4267m
765	800	3.~~6~~5m	3.6m	3.6m	3.7m	3.7m	3.8m	3.8m	3.9m	4.0m	4.0m	4.1m	4.1m	4.2m	4.2m	4.3m
500	550	~~1.57~~2.1m	~~1.6~~2.2m	~~1.66~~2.2m	~~1.73~~2.3m	~~1.79~~2.3m	~~1.85~~2.3m	~~1.91~~2.4m	~~1.98~~2.4m	~~2.04~~2.5m	~~2.~~2.~~11~~.5m	~~2.17~~2.5m	~~2.24~~2.6m	2.6m	2.7m	2.7m
345	362	~~0.97~~1.3m	~~0.99~~1.3m	~~1.0~~1.3m	~~1.08~~1.4m	~~1.12~~1.4m	~~1.16~~1.4m	~~1.21~~1.5m	~~1.26~~1.5m	~~1.30~~.5m	~~1.35~~1.6m	~~1.40~~1.6m	~~1.44~~1.6m	1.6m	1.7m	1.7m
287	302	~~1.18~~1.6m	~~0.88~~1.6m	~~1.26~~1.7m	~~1.31~~1.7m	~~1.36~~1.7m	~~1.41~~1.7m	~~1.46~~1.8m	~~1.51~~1.8m	~~1.57~~1.9m	~~1.62~~1.9m	~~1.68~~1.9m	~~1.73~~2.0m	2.0m	2.0m	2.1m
230	242	~~0.92~~1.2m	~~0.94~~1.3m	~~0.98~~1.3m	~~1.02~~1.3m	~~1.06~~1.3m	~~1.11~~1.3m	~~1.15~~1.4m	~~1.19~~1.4m	~~1.24~~1.4m	~~1.29~~1.5m	~~1.33~~1.5m	~~1.38~~1.5m	1.6m	1.6m	1.6m
161*	169	~~0.62~~0.8m	~~0.64~~0.8m	~~0.67~~0.9m	~~0.69~~0.9m	~~0.73~~0.9m	~~0.76~~0.9m	~~0.79~~0.9m	~~0.82~~1.0m	~~0.85~~1.0m	~~0.89~~1.0m	~~0.92~~1.0m	~~0.96~~1.0m	1.1m	1.1m	1.1m
138*	145	~~0.53~~0.7m	~~0.54~~0.7m	~~0.57~~0.7m	~~0.59~~0.7m	~~0.62~~0.7m	~~0.65~~0.7m	~~0.67~~0.8m	~~0.70~~0.8m	~~0.73~~0.8m	~~0.76~~0.9m	~~0.79~~0.9m	~~0.82~~0.9m	0.9m	0.9m	0.9m
115*	121	~~0.44~~0.6m	~~0.45~~0.6m	~~0.47~~0.6m	~~0.49~~0.6m	~~0.51~~0.6m	~~0.53~~0.6m	~~0.56~~0.6m	~~0.58~~0.7m	~~0.61~~.07m	~~0.63~~0.7m	~~0.66~~0.7m	~~0.69~~0.7m	0.8m	0.8m	0.8m
88*	100	~~0.36~~0.4m	~~0.37~~0.4m	~~0.38~~0.5m	~~0.40~~0.5m	~~0.42~~0.5m	~~0.44~~0.5m	~~0.46~~0.6m	~~0.48~~0.6m	~~0.50~~0.6m	~~0.52~~0.6m	~~0.54~~0.6m	~~0.57~~0.6m	0.6m	0.6m	0.6m
69*	72	~~0.26~~0.3m	~~0.26~~0.3m	~~0.27~~0.3m	~~0.29~~0.4m	~~0.30~~0.4m	~~0.31~~0.4m	~~0.33~~0.4m	~~0.34~~0.4m	~~0.36~~0.4m	~~0.37~~0.4m	~~0.39~~0.4m	~~0.41~~0.4m	0.4m	0.5m	0.5m

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

[+] *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the NERC Advisory posted on May 14, 2015.*

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[19] 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.

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

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[21~~7~~]

For **Direct Current** Voltages feet (meters)

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

[21] 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.

Guideline and Technical Basis

Effective dates:

The Compliance section ~~The first two sentences of the Effective Dates section~~ is standard language used in most NERC standards to cover the general effective date and ~~s sufficient to c~~covers the vast majority of situations. ~~Five~~ A special case~~s~~ ~~are needed to~~ covers effective dates for (1) ~~individual lines which undergo transitions after the general effective date. These special cases cover the effective dates for those~~ lines initially becoming subject to the Standard, (2) ~~which are initially becoming subject to the standard, those lines which are changing their applicability within the standard, and those~~ lines ~~which are~~ changing i~~n a manner that removes their~~ applicability ~~to~~within the standard.

The special case is needed because the Planning Authorities 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 Authority in 2015 may identify a line to have that designation beginning in PY 2025, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. 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 1 is needed because the Planning Coordinators may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2011 may identify a line to have that designation beginning in PY 2021, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. The table below has some explanatory examples of the application.~~

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

05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

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

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

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

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

Defined Terms:

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

easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

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

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

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

Explanation of the ~~definition~~ derivation 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. The table is based on empirical testing data from EPRI as requested by FERC in Order No. 777. ~~Details of the equations and an example calculation are provided in Appendix 1 of the Technical Reference Document.~~

Project 2010-07.1 Adjusted MVCDs per EPRI Testing:
In Order No. 777, FERC directed NERC to undertake testing to gather empirical data validating the appropriate gap factor used in the Gallet equation to calculate MVCDs, specifically the gap factor for the flash-over distances between conductors and vegetation. See, Order No. 777, at P 60. NERC engaged industry through a collaborative research project and contracted EPRI to complete the scope of work. In January 2014, NERC formed an advisory group to assist with developing the scope of work for the project. This team provided subject matter expertise for developing the test plan, monitoring testing, and vetting the analysis and conclusions to be submitted in a final report. The advisory team comprised NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulation coordination, and vegetation management. The testing project commenced in April 2014 and continued through October 2014 with the final set of testing completed in May 2015. Based on these testing results conducted by EPRI, and consistent with the report filed in FERC Docket No. RM12-4-000, the gap factor used in the Gallet equation require adjustment from 1.3 to 1.0. This resulted in increased MVCD values for all alternating current system voltages identified. The adjusted MVCD values, reflecting the 1.0 gap factor, are included in Table 2 of version 4 of FAC-003.

The air gap testing completed by EPRI per FERC Order No. 777 established that trees with large spreading canopies growing directly below energized high voltage conductors create the

greatest likelihood of an air gap flash over incident and was a key driver in changing the gap factor to a more conservative value of 1.0 in version 4 of this standard.

Requirements R1 and R2:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

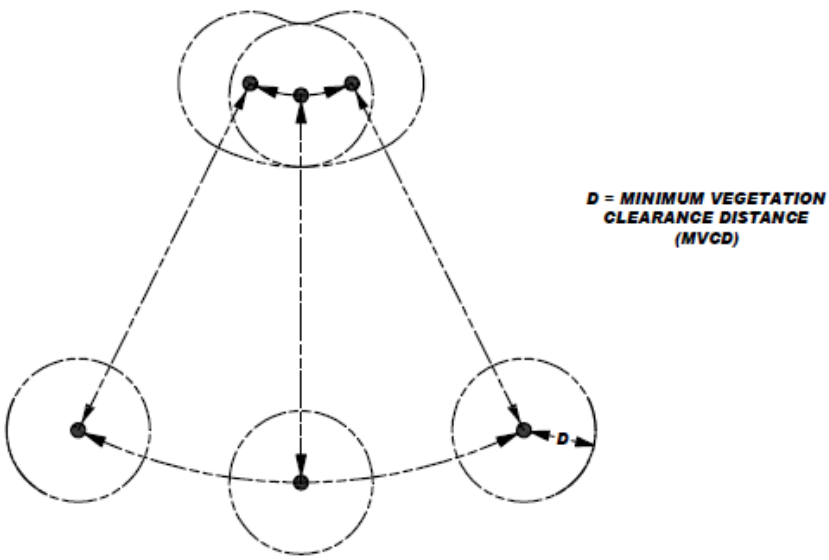

Figure 1

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

Requirement R4:
R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

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

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

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

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

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

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

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

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

Requirement R6:

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

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission

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

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

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

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

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner's or applicable Generator Owner's system to work on another system. Any of these examples could result in

acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.

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

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

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

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.

Since no empirical data for spark over distances to live vegetation existed at the time version 3 was developed, the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

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

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

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

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

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

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

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

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

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

Rationale for R3:
The documentation provides a basis for evaluating the competency of the applicable Transmission Owner's or applicable Generator Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions. ~~See Figure~~

Rationale for R4:
This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

Rationale for R5:
Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

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

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

Rationale for R6:
Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

Rationale for R7:
This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

NERC
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Implementation Plan for FAC-003-4 — Transmission Vegetation Management

Requested Approval
FAC-003-4 – Transmission Vegetation Management

Requested Retirement
FAC-003-3 – Transmission Vegetation Management

Prerequisite Approvals
None.

Defined Terms in the NERC Glossary
None.

Effective Date
Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 3 months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 3 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Compliance Note

A line operated below 200kV, designated by the Planning Authority 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 Authority 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.

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.

Standard for Retirement

FAC-003-3 11:59:59 p.m. on the day immediately prior to the Effective Date of FAC-003-4 in the particular jurisdiction in which the FAC-003-4 standard is becoming effective.

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Unofficial Comment Form

Project 2010-07.1 Vegetation Management

DO NOT use this form for submitting comments. Use the electronic form to submit comments on the draft FAC-003-4 Reliability Standard by **8:00 p.m. Eastern, December 16, 2015.**

Documents and information about this project are available on the project page. If you have questions contact Standards Developer, Sean Bodkin (via email) or at (202) 400-3022.

Background Information

In Order No. 777, the FERC directed NERC to provide empirical data validating the gap factor for flashover distances between conductors and vegetation used in the Gallet equation to calculate Minimum Vegetation Clearance Distances (MVCDs) in NERC Reliability Standard FAC-003-2. In the order, FERC directed NERC to submit: (1) a schedule for testing; (2) the scope of work; (3) funding solutions; and (4) a deadline for submitting a final report on the test results to FERC, along with interim reports if a multiyear study is conducted.[1] NERC contracted the EPRI and performed a collaborative research project to complete the work. NERC submitted a compliance filing on July 12, 2013,[2] which FERC accepted on September 4, 2013.[3]

In January 2014, NERC formed an advisory group to develop the scope of work for the project. This team of subject matter experts assisted in developing the test plan, which included monitoring the testing and analyzing the test results to be provided in a final report. The advisory team was comprised of NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulator characteristics, and vegetation management. The project's scope of work and the detailed test plan were finalized in March 2014.

The testing project commenced in April 2014 and continued through October 2014, when EPRI completed the prescribed tests to validate the gap factor applied in the Gallet equation. NERC filed an informational filing with FERC on July 31, 2014,[4] that contained the results of the testing work completed to date. The initial analysis, containing preliminary conclusions and recommendations, concluded in early 2015. Based on the preliminary results, the gap factor used in the Gallet equation required modification from 1.3 to 1.0, which would increase the MVCD values compared to those specified in the existing standard.

NERC, through EPRI, performed additional tests in 2015 to finalize the gap-factor verification. NERC proceeded to communicate the research findings to industry through webinars and committee meetings, and issued an industry advisory alert in May 2015.[5] Final testing was completed and an EPRI report was posted on July 21, 2015. The report determined "that the proposed minimum vegetation clearance

[1] *Revisions to Reliability Standard for Transmission Vegetation Management,* 142 FERC ¶61, 208. at P 61 (2013).
[2] Compliance Filing of NERC, Docket No. RM12-4-000 (Jul. 12, 2013).
[3] *N. Am. Elec. Reliability Corp.*, Docket No. RM12-4-001 (Sept. 4, 2013) (delegated letter order).
[4] Informational Filing of NERC, Docket Nos. RM12-4-000 and RM12-4-001 (Jul. 31, 2014).
[5] Industry Advisory Alert - FAC-003-3 MVCD

distances (MVCD), based on a gap factor of 1.3, should be increased and the corresponding gap factor reduced to a more conservative value of 1.0."[6]

The Vegetation Management Standard Drafting Team (SDT) posted a revised SAR and associated documents for comment August 24 – September 28, 2015. Based on comments received during this posting, the SDT made the following revisions:

- Updated the Gap Factor in Table 2 of FAC-003-4, both in feet and meters.
- Based on feedback received during the advisory group, the SDT added the MVCD up to 15,000 feet and 4,267 meters.
- Updated the term "Planning Coordinator" to "Planning Authority" for consistency purposes with FAC-014, which uses "Planning Authority." Additionally, the NERC Glossary of Terms states to "See Planning Authority"[7] for the continent-wide term "Planning Coordinator."
- Updated the Guideline and Technical Basis Section for history purposes and current additions.
- Updated FAC-003 standard to the new Results-Based template. Updated template sections are as follows:
    - Effective date section has been updated to state "See Implementation Plan." A link to the Implementation Plan will be located in the Associated Documents section of FAC-003-4.
    - Compliance Section has been updated for consistency purposes with the Rules of Procedure.

[6] Electric Power Research Institute. *Supplemental Testing to Confirm or Refine Gap Factor Utilized in Calculation of Minimum Vegetation Clearance Distances (MVCD).* 1-1. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002006527

[7] Glossary of Terms Used in NERC Reliability Standards (September 29, 2015): http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf

Questions

1. Do you agree with the FAC-003-4 table 2 MVCD values? If not, please provide your response below.

   ☐ Yes
   ☐ No

   Comments:

2. Do you agree with modifying the elevation levels in table 2 to go up to 15,000 feet and 4,267 meters? If not, please provide your response below.

   ☐ Yes
   ☐ No

   Comments:

3. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

   ☐ Yes
   ☐ No

   Comments:

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Standards Authorization Request Form

When completed, email this form to:
Barbara.Nutter@nerc.net

For questions about this form or for assistance in completing the form, call Barb Nutter at 404-446-9692.

NERC welcomes suggestions for improving the reliability of the Bulk-Power System through improved Reliability Standards. Please use this form to submit your proposal for a new NERC Reliability Standard or a revision to an existing standard.

Request to propose a new or a revision to a Reliability Standard			
Proposed Standard:	FAC-003-4		
Date Submitted:	August 19, 2015		
SAR Requester Information			
Name:	Minimum Vegetation Clearance Distances (MVCD) Advisory Group [Ron Adams]		
Organization:	Duke Energy		
Telephone:	(704) 382-7338	E-mail:	Ron.adams@duke-energy.com
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
Correct the Gallet equation gap factors to reflect new information from Electric Power Research Institute (EPRI) study.
Purpose or Goal (How does this request propose to address the problem described above?):
The primary goal of this SAR is to address the findings of the EPRI report in the FAC-003 Reliability Standard.

SAR Information
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
Provide the appropriate minimum vegetation clearances distances within the FAC-003 standard.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The SDT shall modify FAC-003-3 to reflect the findings of the EPRI study.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
At the time the FAC-003-3 Reliability Standard was filed there was some question regarding the gap factors contained in the Gallet equation. To validate the gap factors, NERC contracted with EPRI to complete further studies. The preliminary report indicates the need for a modification to the gap factors. The drafting team will be modifying the standard based on the final report, which was published on July 21, 2015. Click here for: the final EPRI report.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☐ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.

Reliability Functions		
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☒	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
N/A	

Related Standards	

Related SARs	
SAR ID	Explanation
N/A	N/A

Regional Variances	
Region	Explanation
ERCOT	N/A
FRCC	N/A
MRO	N/A
NPCC	N/A
RFC	N/A
SERC	N/A
SPP	N/A
WECC	N/A

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Standards Announcement

Project 2010-07.1 Vegetation Management FAC-003-4

Formal Comment Period Open through December 16, 2015
Ballot Pool Forming through November 30, 2015

Now Available

A 45-day formal comment period for **FAC-003-4 - Transmission Vegetation Management**, is open through **8 p.m. Eastern, Wednesday, December 16, 2015.**

Commenting

Use the electronic form to submit comments on the standard. If you experience any difficulties in using the electronic form, contact Nasheema Santos. An unofficial Word version of the comment form is posted on the project page.

Join the Ballot Pool

The ballot pool is being formed through **8 p.m. Eastern, Monday, November 30, 2015**. Registered Ballot Body members may join the ballot pool here.

If you are having difficulty accessing the Standards Balloting & Commenting System due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at EROhelpdesk@nerc.net *(Monday – Friday, 8 a.m. - 8 p.m. Eastern).*

Next Steps

An initial ballot for the standard will be conducted **December 7-16, 2015**. A non-binding poll for the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) will not be conducted due to the fact that only non-substantive changes were made to the requirements, and no changes made to the VRFs and VSLs.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Sean Bodkin (via email) or at (202) 400-3022.

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Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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Project 2010-07.1 Vegetation Management FAC-003-4

Draft Reliability Standard Authorization Worksheet (RSAW) Posted for Industry Comment through December 16, 2015

Now Available

The draft RSAW for **FAC-003-4 – Transmission Vegetation Management** is posted on the project page for industry comment through **8 p.m. Eastern, Wednesday, December 16, 2015.** This draft RSAW has no substantive changes from the RSAW for FAC-003-3. Submit feedback to RSAWfeedback@nerc.net.

For more information or assistance, contact Standards Developer, Sean Bodkin (via email) or at (202) 400-3022.

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Standards Announcement

Project 2010-07.1 Vegetation Management FAC-003-4

Initial Ballot Results

Now Available

An initial ballot for **FAC-003-4 – Transmission Vegetation Management** concluded **8 p.m. Eastern, December 16, 2015.**

The standard received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides the detailed results.

Ballot
Quorum / Approval
85.38% / 82.56%

Next Steps
The drafting team will consider all comments received during the formal comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the Standard Processes Manual

For more information or assistance, contact Standards Developer, Sean Bodkin (via email) or at (202) 400-3022.

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BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/39)
Ballot Name: 2010-07.1 Vegetation Management FAC-003-4 IN 1 ST
Voting Start Date: 12/7/2015 12:01:00 AM
Voting End Date: 12/16/2015 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 257
Total Ballot Pool: 301
Quorum: 85.38
Weighted Segment Value: 82.56

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	83	1	62	0.861	10	0.139	0	2	9
Segment: 2	3	0.3	2	0.2	1	0.1	0	0	0
Segment: 3	68	1	50	0.877	7	0.123	0	1	10
Segment: 4	18	1	14	0.933	1	0.067	0	0	3
Segment: 5	70	1	47	0.855	8	0.145	0	2	13
Segment: 6	47	1	35	0.875	5	0.125	0	0	7
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	3	0.2	1	0.1	1	0.1	0	0	1
Segment:	2	0.1	1	0.1	0	0	0	0	1

9									
Segment: 10	7	0.7	4	0.4	3	0.3	0	0	0
Totals:	301	6.3	216	5.201	36	1.099	0	5	44

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Negative	Third-Party Comments
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	Andrew Pusztai		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	ATCO Electric	David Downey	Dan Bamber	Negative	Comments Submitted
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A

1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Affirmative	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Bruce Bugbee		Affirmative	N/A
1	Colorado Springs Utilities	Shawna Speer		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Affirmative	N/A
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Negative	Third-Party Comments
1	Duke Energy	Doug Hils		None	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A

1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Negative	Third-Party Comments
1	Iberdrola - Central Maine Power Company	Joe Turano		Negative	Third-Party Comments
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Negative	Third-Party Comments
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A

1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Negative	Third-Party Comments
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Charles Raney		None	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Rod Kinard	Tammy Porter	Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Peak Reliability	Jared Shakespeare		None	N/A
1	PHI - Potomac Electric Power Co.	David Thorne		Affirmative	N/A
1	Platte River Power Authority	John Collins		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	John Walker		Negative	Third-Party Comments
1	PPL Electric Utilities	Brenda Truhe		Affirmative	N/A

	Corporation				
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Sacramento Municipal Utility District	Tim Kelley	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		None	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		None	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Affirmative	N/A
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		Affirmative	N/A
1	Southwest Transmission Cooperative, Inc.	John Shaver		Affirmative	N/A
1	Sunflower Electric Power Corporation	Bertha Ellen Watkins		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A

1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Negative	Third-Party Comments
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Affirmative	N/A
2	Herb Schrayshuen	Herb Schrayshuen		Negative	Comments Submitted
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Shuye Teng		None	N/A
3	Avista - Avista Corporation	Scott Kinney		Negative	Comments Submitted
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Negative	Comments Submitted

3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Farmington	Linda Jacobson-Quinn		Negative	Third-Party Comments
3	City of Redding	Elizabeth Hadley	Bill Hughes	None	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		None	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Kent Kujala		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Chris Gowder	Affirmative	N/A
3	Georgia System Operations	Scott McGough		Affirmative	N/A

	Corporation				
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	David Hadzima		None	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn		None	N/A

3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Blaine Dinwiddie		None	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	PHI - Potomac Electric Power Co.	Mark Yerger		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	Portland General Electric Co.	Thomas Ward		Negative	Third-Party Comments
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		None	N/A
3	Sacramento Municipal Utility District	Rachel Moore	Joe Tarantino	Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		None	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Jim Cox		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A

3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		None	N/A
3	WEC Energy Group, Inc.	James Keller		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	Blue Ridge Power Agency	Duane Dahlquist		Affirmative	N/A
4	City of Redding	Nick Zettel	Bill Hughes	None	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		None	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh	John Reed	Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish	John Martinsen		Affirmative	N/A

	County				
4	Sacramento Municipal Utility District	Michael Ramirez	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Negative	Third-Party Comments
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Affirmative	N/A
5	Austin Energy	Jeanie Doty		None	N/A
5	Avista - Avista Corporation	Steve Wenke		Negative	Comments Submitted
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	BC Hydro and Power Authority	Clement Ma		None	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A

5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Abstain	N/A
5	City and County of San Francisco	Daniel Mason		Negative	Comments Submitted
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Mike Hirst		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		None	N/A
5	Edison International - Southern California Edison Company	Michael McSpadden		Affirmative	N/A
5	EDP Renewables North America LLC	Heather Morgan		None	N/A
5	Essential Power, LLC	Gerry Adamski		None	N/A
5	Exelon	Vince Catania		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann	Chris Gowder	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Negative	Comments Submitted

5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Lower Colorado River Authority	Dixie Wells		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Negative	Third-Party Comments
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	NB Power Corporation	Rob Vance		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Wayne Sipperly		Negative	Third-Party Comments
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		None	N/A
5	Oglethorpe Power Corporation	Bernard Johnson		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A

5	OTP - Otter Tail Power Company	Cathy Fogale		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Dan Wilson		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		None	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	SCANA - South Carolina Electric and Gas Co.	Henry Delk		None	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Negative	Third-Party Comments
5	Tallahassee Electric (City of Tallahassee,	Karen Webb		Affirmative	N/A

	FL)				
5	Tennessee Valley Authority	Brandy Spraker		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A
5	U.S. Bureau of Reclamation	Erika Doot		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	stephanie johnson		Affirmative	N/A
5	Xcel Energy, Inc.	David Lemmons		None	N/A
6	AEP - AEP Marketing	Edward P Cox		None	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		None	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Third-Party Comments
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	City of Redding	Marvin Briggs	Bill Hughes	None	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Louis Slade		Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Edison International - Southern California Edison Company	Earle Saunders		Affirmative	N/A
6	Exelon	Dave Carlson		Affirmative	N/A

6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Chris Gowder	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	None	N/A
6	Iberdrola - New York State Electric and Gas Corporation	Julie King		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik	Simon Tanapat	Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Affirmative	N/A
6	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
6	Platte River Power Authority	Carol Ballantine		Affirmative	N/A
6	Portland General Electric Co.	Shawn Davis		Negative	Comments Submitted

6	PPL - Louisville Gas and Electric Co.	OELKER LINN		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		Affirmative	N/A
6	Sacramento Municipal Utility District	Diane Clark	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Kenn Backholm		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	John J. Ciza		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Brad Lisembee		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Negative	Third-Party Comments
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Megan Wagner		Affirmative	N/A
6	Xcel Energy, Inc.	Peter Colussy		None	N/A
8	David Kiguel	David Kiguel		None	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Negative	Third-Party

					Comments
9	City of Vero Beach	Ginny Beigel	Chris Gowder	Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Negative	Comments Submitted
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Negative	Comments Submitted
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted

Previous 1 Next

Showing 1 to 301 of 301 entries

Survey Report

Survey Details

Name 2010-07.1 Vegetation Management | FAC-003-4

Description

Start Date 10/30/2015

End Date 12/16/2015

Associated Ballots

2010-07.1 Vegetation Management FAC-003-4 IN 1 ST

Survey Questions

1. Do you agree with the FAC-003-4 table 2 MVCD values? If not, please provide your response below.

Yes

No

2. Do you agree with modifying the elevation levels in table 2 to go up to 15,000 feet and 4,267 meters? If not, please provide your response below.

Yes

No

3. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

Responses By Question

1. Do you agree with the FAC-003-4 table 2 MVCD values? If not, please provide your response below.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

William Hutchison - Southern Illinois Power Cooperative - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Falsey - Invenergy LLC - 5,6 - FRCC,MRO,WECC,TRE,NPCC,SERC,SPP,RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rob Robertson - SunEdison - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Randall Hubbard - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - FRCC,WECC,TRE,SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc..	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R. Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Voter Information

Voter

Randall Hubbard

Segment

1,3,5,6

Entity

Southern Company - Southern Company Services, Inc.

Region(s)

FRCC,WECC,TRE,SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter	Segment
Richard Hoag	1,3,4,5,6
Entity	**Region(s)**
FirstEnergy - FirstEnergy Corporation	RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dan Bamber - Dan Bamber On Behalf of: David Downey, ATCO Electric,1

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Herb Schrayshuen - Herb Schrayshuen - 2 -

Selected Answer: No

Answer Comment:

The tables are missing columns (or the headers are wrong) and have some number transpositions. In the english (ft) version of the table the range between 13000' and 14000' is missing. Additionaly the rounding mathematics used to generate the tables may not be the most conservative. For clearances one should round up in all instances.

There is no issue with the underlying clearance numbers that resulted from the laboratory testing. The issue is with the translation into the standard. It appears some more quality control and independent review should have been applied.

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: No

Answer Comment:

While AEP does not object to the newly-proposed English values in Table 2, these values are not equivalent to the metric values provided in the same table. AEP requests that the drafting team review both the English and Metric values, and provide corrections as necessary.

Document Name:

Likes: 0

Dislikes: 0

Roger Dufresne - Hydro-Qu?bec Production - 5 -

Selected Answer: No

Answer Comment:
See comments from TransEnergie

Document Name:

Likes: 0

Dislikes: 0

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Information

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Voter Information

Voter

Randi Heise

Segment

5

Entity

Dominion - Dominion Resources, Inc.

Region(s)

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Amy Casucelli	Xcel Energy	MRO	1,3,5,6

Voter Information

Voter	**Segment**
Emily Rousseau	1,2,3,4,5,6
Entity	**Region(s)**
MRO	MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michelle Amarantos - APS - Arizona Public Service Co. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Laura Nelson - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tammy Porter - Tammy Porter On Behalf of: Rod Kinard, Oncor Electric Delivery,1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Steven Rueckert - Western Electricity Coordinating Council - 10 -

Selected Answer: No

Answer Comment:

There are several typos in the table. In the "over 2133.6 m to 2438.4 m" column, the cell for 345 kV should be 1.5m, not .5m and the cell for 115 kV should be 0.7m, not .07m.

The added columns on the English table are missing the 13,000-14,000 ft range. The added columns on the Metric table stop at 14000 ft. The 14000-15000 ft column is not there. The two tables are inconsistent.

MVCD in the DC table did not change. Is this correct?

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Angela Gaines - Portland General Electric Co. - 1,3,5,6 - WECC

Selected Answer: No

Answer Comment:
Please see WECC's position paper for details

Document Name:

Likes: 0

Dislikes: 0

Steve Wenke - Avista - Avista Corporation - 5 -

Selected Answer: No

Answer Comment:

The following is an excerpt from the WECC position paper:

In summary, the following changes should be made before approval:

· Correct the Functional Entity from “Planning Authority” to “Planning Coordinator”

· The added columns in Table 2 for vegetation management over 12,000ft are superfluous and not needed.

· Although not needed, the column for 14,000 to 15,000 is inadvertently skipped.

· Table 2 – (meters) contains typographical errors; A) for Over 2133.6 m, 345kV MVCD should be 1.5, not .5m; and B) for Over 2133.6 m, 115kV MVCD should be 0.7, not .07m,

· Although distances for AC lines are increased by 30% due to the study, there has been no increase in the distances for the DC lines, and no explanation is given. These distances should be considered for revision.

· For ease-of-use, the columns from “Over sea level up to 500 ft” and “Over 500 ft up to 1000 ft” should be combined to a single column “Over sea level up to 1000 ft”…only one cell will change by one tenth of a foot in only the 765kV voltage class.

· The elevation columns in the “meters” page of Table 2, are calculated to exactly match the elevations in feet, in the process the elevations given are un-workable. Elevations of 304.8m, 609.6m, 914.4m, etc. should be changed to 300m, 600m, 900 m. The MVCD’s (rounded to within one tenth of a foot) will not change.

· In Table 2 for Direct Current, the MVCD’s are calculated to within one hundredth of a foot – this is an un-workable level of precision.

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Information

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Voter Information

Voter

Colby Bellville

Segment

1,3,5,6

Entity

Duke Energy

Region(s)

FRCC,SERC,RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:

Texas RE noticed the following:

- There is not an “Over 13000 ft up to 14000 ft” column provided. Should there be?
- There is an incorrect value in the MVCD meters table in the last two columns. One column references “….up to 3962m” and the final column references “Over 3692 m….” so there appears to be transposed values
- On Table 2, there is no column for Over 13000 ft up to 14000 ft. The values in the “Over 14000 ft up to 15000 ft” within the Standard match the values of the “Over 13,000 ft up to 14,000 ft” values in the May 14, 2015 Industry Advisory. Is that correct? Based on the nature of the data (a general increase for most, if not all, 1000 ft elevation increase) it does not appear reasonable.
- It does not appear that there is consistency in the values. When you review the voltage levels increasing (e.g. 230 kV to 287 kV) it appears that the MVCD increase (e.g., at “sea level up to 500 ft” the MVCD increase from 4.0 ft to 5.2 ft). The increasing pattern appears to not be followed when it reaches the 345 kV level. The MVCD actually decreases when compared to a 287 kV level. Why does that occur? Was there a different parameter used in the derivation of Gallet’s equation for the 345 kV level? Ascertaining the correct value for the 345 kV level is highly critical for the ERCOT Interconnection (in both measurement type versions of the table.)
- Similar to the comment above, the MVCD for 345 kV lines from 2133.6m to 2438.4m is .5m, which is less than the MVCD of 1.5m and 1.6m for the altitudes immediately before and after in the table. This appears to be a typo and the MVCD for 345 kV lines 2133.6m to 2438.4m should be 1.5m.
- Table 2 for AC Voltages does not include lines at altitudes between 3352.8m and 3353m.
- There appears to be an inconsistency in the “meter” version of Table 2. The “older columns” have decimal point step increases (e.g. “Over 2133.6m up to 2438.4m”) that are carried over to the next columns as a starting point (e.g. “Over 2438.4m up to….”). The new columns do not utilize the same formatting.

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Diana McMahon - Salt River Project - 1,3,5,6 - WECC

Selected Answer: No

Answer Comment:

SRP appreciates the opportunity to review and comment on the adjustments to the standard. We support the work of the drafting team, but request a review and revision of the tables to reflect issues identified in the WECC position paper including:

- The column for 14,000 to 15,000 is inadvertently skipped.
- Table 2 – (meters) contains typographical errors; A) for Over 2133.6 m, 345kV MVCD should be 1.5, not .5m; and B) for Over 2133.6 m, 115kV MVCD should be 0.7, not .07m,
- Although distances for AC lines are increased by 30% due to the study, there has been no increase in the distances for the DC lines, and no explanation is given. These distances should be considered for revision.
- For ease-of-use, the columns from “Over sea level up to 500 ft” and “Over 500 ft up to 1000 ft” should be combined to a single column “Over sea level up to 1000 ft”…only one cell will change by one tenth of a foot in only the 765kV voltage class.
- The elevation columns in the “meters” page of Table 2, are calculated to exactly match the elevations in feet, in the process the elevations given are un-workable. Elevations of 304.8m, 609.6m, 914.4m, etc. should be changed to 300m, 600m, 900 m. The MVCD’s (rounded to within one tenth of a foot) will not change.
- In Table 2 for Direct Current, the MVCD’s are calculated to within one hundredth of a foot – this is an un-workable level of precision

Document Name:

Likes: 0

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Information

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Voter Information

Voter

Ginette Lacasse

Segment

1,3,4,5,6

Entity

Seattle City Light

Region(s)

WECC

Selected Answer: No

Answer Comment:

We support WECC Position paper, Dec 7, 2015: Table 2– (meters) contains typographical errors; A) for Over 2133.6 m, 345kV MVCD should be 1.5, not .5m; and B) for Over 2133.6 m, 115kV MVCD should be 0.7, not .07m,

Document Name:

Likes: 0

Dislikes: 0

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC

Group Information

Group Name: RSC without Con Edison

Group Member Name	Entity	Region	Segments
Paul Malozewski	Hydro One.	NPCC	1
Guy Zito	Northeast Power Coordinating Council	NPCC	NA - Not Applicable
Brian Shanahan	National Grid	NPCC	1
Rob Vance	New Brunswick Power	NPCC	1
Robert J. Pellegrini	United Illuminating	NPCC	1
Sylvain Clermont	Hydro Quebec	NPCC	1
Edward Bedder	Orange and Rockland Utilities	NPCC	1
Mark J. Kenny	Eversource Energy	NPCC	1
Gregory A. Campoli	NY-ISO	NPCC	2
Si Truc Phan	Hydro Quebec	NPCC	2
Randy MacDonald	New Brunswick Power	NPCC	2
David Burke	Orange and Rockland Utilities	NPCC	3
Wayne Sipperly	New York Power Authority	NPCC	4
Connie Lowe	Dominion Resources Services	NPCC	4
David Ramkalawan	Ontario Power Generation	NPCC	4
Glen Smith	Entergy Services	NPCC	4
Brian O'Boyle	Con Edison	NPCC	5
Brian Robinson	Utility Services	NPCC	5
Bruce Metruck	New York Power Authority	NPCC	6
Alan Adamson	New York State Reliability Council	NPCC	7
Kathleen M. Goodman	ISO-New England	NPCC	2
Helen Lainis	Independent Electricity System Operator	NPCC	2
Michael Jones	National Grid	NPCC	3
Silvia Parada Mitchell	NextEra Energy	NPCC	4

Voter Information

Voter	Segment
Ruida Shu	1,2,3,4,5,6,7

Entity **Region(s)**

Northeast Power Coordinating Council NPCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Patricia Robertson - BC Hydro and Power Authority - 1 -

Group Information

Group Name: BC Hydro

Group Member Name	Entity	Region	Segments
Patricia Robertson	BC Hydro and Power Authority	WECC	1
Venkataramakrishnan Vinnakota	BC Hydro and Power Authority	WECC	2
Pat G. Harrington	BC Hydro and Power Authority	WECC	3
Clement Ma	BC Hydro and Power Authority	WECC	5

Voter Information

Voter	Segment
Patricia Robertson	1
Entity	**Region(s)**
BC Hydro and Power Authority	

Selected Answer: Yes

Answer Comment:

BC Hydro agrees with the revised Table 2 MVCD values based on a Gallet equation gap factor of 1.0. However we would point out one typo on the metric distance table for 345 kV in the 2133.6-2438.4 m elevation column. The distance stated should be 1.5 m not 0.5 m as in the table and should be corrected.

Document Name:

Likes: 0

Dislikes: 0

Peter Heidrich - Florida Reliability Coordinating Council - 10 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Daniel Mason - City and County of San Francisco - 5 -

Selected Answer: No

Answer Comment:

Hetch Hetchy Water and Power believes the changes recommended in the attached WECC FAC-003-4 position paper should be considered prior to the approval of FAC-003-4.

Document Name: 12-10-15 WECC Position Paper on FAC-003-4.docx

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
J. Scott Williams	City Utilities of Springfield	SPP	1,4

Jim Nail	City of Independence, Power & Light Department	SPP	3,5
John Falsey	Invenergy	NA - Not Applicable	NA - Not Applicable
John Allen	City Utilities of Springfield	SPP	1,4
Kevin Giles	Westar Energy Inc..	SPP	1,3,5,6
Louis Guidry	Cleco Corporation	SPP	1,3,5,6
Michelle Corley	Cleco Corporation	SPP	1,3,5,6
Mike Kidwell	Empire District Electric	SPP	1,3,5
Robert Hirchak	Cleco Corporation	SPP	1,3,5,6

Voter Information

Voter	Segment
Shannon Mickens	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer: Yes

Answer Comment:

Our group is in support of table 2 however, we have discovered that the values are not equivalent to the metric values provided in the same table. We would requests that the drafting team review both the English and Metric values, and provide corrections as necessary.

Document Name:

Likes: 0

Dislikes: 0

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Ryan Strom	Buckeye Power, Inc.	RFC	4
Amber Skillern	East Kentucky Power Cooperative	SERC	1,3
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5
Scott Brame	North Carolina Electric Membership Corporation	SERC	3,4,5
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1

Voter Information

Voter	Segment
Colleen Campbell	6
Entity	**Region(s)**
ACES Power Marketing	NA - Not Applicable

Selected Answer: Yes

Answer Comment:

We agree with the values listed in Table 2, as derived from EPRI's empirical studies.

Document Name:

Likes: 0

Dislikes: 0

Oshani Pathirane - Oshani Pathirane On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

2. Do you agree with modifying the elevation levels in table 2 to go up to 15,000 feet and 4,267 meters? If not, please provide your response below.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

William Hutchison - Southern Illinois Power Cooperative - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Falsey - Invenergy LLC - 5,6 - FRCC,MRO,WECC,TRE,NPCC,SERC,SPP,RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rob Robertson - SunEdison - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Randall Hubbard - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - FRCC,WECC,TRE,SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc..	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R. Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Voter Information

Voter

Randall Hubbard

Segment

1,3,5,6

Entity

Southern Company - Southern Company Services, Inc.

Region(s)

FRCC,WECC,TRE,SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter	Segment
Richard Hoag	1,3,4,5,6
Entity	**Region(s)**
FirstEnergy - FirstEnergy Corporation	RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dan Bamber - Dan Bamber On Behalf of: David Downey, ATCO Electric,1

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Herb Schrayshuen - Herb Schrayshuen - 2 -

Selected Answer: Yes

Answer Comment:
Yes, but the tree line in North America may not be that high.

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Roger Dufresne - Hydro-Qu?bec Production - 5 -

Selected Answer:

Answer Comment:
See comments from TransEnergie

Document Name:

Likes: 0

Dislikes: 0

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Information

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Voter Information

Voter

Randi Heise

Segment

5

Entity

Dominion - Dominion Resources, Inc.

Region(s)

Selected Answer: Yes

Answer Comment:

Table 2 - Minimum Vegetation Clearance Distances (MVCD) For Alternating Current Voltage (feet) is missing the data column located between “Over 12,000 ft” and “Over 14,000 ft”. The column “Over 13, 000 ft” is not included in the table.

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: No

Answer Comment:
Hydro-Quebec TransEnergie support NPCC comments

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6

Tony Eddleman	Nebraska Public Power District	MRO	1,3,5
Amy Casucelli	Xcel Energy	MRO	1,3,5,6

Voter Information

Voter	Segment
Emily Rousseau	1,2,3,4,5,6
Entity	**Region(s)**
MRO	MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michelle Amarantos - APS - Arizona Public Service Co. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Laura Nelson - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

Idaho Power's transmission system has no facilities at or near the stated elevation.

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tammy Porter - Tammy Porter On Behalf of: Rod Kinard, Oncor Electric Delivery,1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Steven Rueckert - Western Electricity Coordinating Council - 10 -

Selected Answer: No

Answer Comment:

Do not understand the need to go this high. I believe it is well above the treeline/timberline. If there is no vegetation, there is no need to manage it.

4267 meters is only 14000 feet not 15000 feet.

However, as long as the tables are consistent, we don't have any problems if they go this high.

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Angela Gaines - Portland General Electric Co. - 1,3,5,6 - WECC

Selected Answer: No

Answer Comment:
Please see WECC's position paper for details

Document Name:

Likes: 0

Dislikes: 0

Steve Wenke - Avista - Avista Corporation - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Information

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Voter Information

Voter

Colby Bellville

Segment

1,3,5,6

Entity

Duke Energy

Region(s)

FRCC,SERC,RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:

Texas RE inquires: was there any consideration for establishing MVCDs for lines that are below sea level (e.g., New Orleans or Death Valley)?

Please see Texas RE's observations in #1.

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Diana McMahon - Salt River Project - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Information

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Voter Information

Voter

Ginette Lacasse

Segment

1,3,4,5,6

Entity

Seattle City Light

Region(s)

WECC

Selected Answer: No

Answer Comment:

We support WECC Position paper, Dec 7, 2015: Table 2– (meters) contains typographical errors; A) for Over 2133.6 m, 345kV MVCD should be 1.5, not .5m; and B) for Over 2133.6 m, 115kV MVCD should be 0.7, not .07m,

Document Name:

Likes: 0

Dislikes: 0

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC

Group Information

Group Name: RSC without Con Edison

Group Member Name	Entity	Region	Segments
Paul Malozewski	Hydro One.	NPCC	1
Guy Zito	Northeast Power Coordinating Council	NPCC	NA - Not Applicable
Brian Shanahan	National Grid	NPCC	1
Rob Vance	New Brunswick Power	NPCC	1
Robert J. Pellegrini	United Illuminating	NPCC	1
Sylvain Clermont	Hydro Quebec	NPCC	1
Edward Bedder	Orange and Rockland Utilities	NPCC	1
Mark J. Kenny	Eversource Energy	NPCC	1
Gregory A. Campoli	NY-ISO	NPCC	2
Si Truc Phan	Hydro Quebec	NPCC	2
Randy MacDonald	New Brunswick Power	NPCC	2
David Burke	Orange and Rockland Utilities	NPCC	3
Wayne Sipperly	New York Power Authority	NPCC	4
Connie Lowe	Dominion Resources Services	NPCC	4
David Ramkalawan	Ontario Power Generation	NPCC	4
Glen Smith	Entergy Services	NPCC	4
Brian O'Boyle	Con Edison	NPCC	5
Brian Robinson	Utility Services	NPCC	5
Bruce Metruck	New York Power Authority	NPCC	6
Alan Adamson	New York State Reliability Council	NPCC	7
Kathleen M. Goodman	ISO-New England	NPCC	2
Helen Lainis	Independent Electricity System Operator	NPCC	2
Michael Jones	National Grid	NPCC	3
Silvia Parada Mitchell	NextEra Energy	NPCC	4

Voter Information

Voter	Segment
Ruida Shu	1,2,3,4,5,6,7

Entity **Region(s)**

Northeast Power Coordinating Council NPCC

Selected Answer: No

Answer Comment:

In table 2 Minimum Vegetation Clearance Distances (MVCD meters) the last two column headers are mislabeled. The last two columns should be “Over 3657m up to 3962m and Over 3962m up to 4267m” per the NERC report.

In Table 2 Minimum Vegetation Clearance Distances (MVCD feet), the last two column headers are mislabeled. In the NERC report the last column is labeled 13,000 ft up to 14,000 ft.

Document Name:

Likes: 0

Dislikes: 0

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Patricia Robertson - BC Hydro and Power Authority - 1 -

Group Information

Group Name: BC Hydro

Group Member Name	Entity	Region	Segments
Patricia Robertson	BC Hydro and Power Authority	WECC	1
Venkataramakrishnan Vinnakota	BC Hydro and Power Authority	WECC	2
Pat G. Harrington	BC Hydro and Power Authority	WECC	3
Clement Ma	BC Hydro and Power Authority	WECC	5

Voter Information

Voter	Segment
Patricia Robertson	1
Entity	**Region(s)**
BC Hydro and Power Authority	

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Peter Heidrich - Florida Reliability Coordinating Council - 10 -

Selected Answer: Yes

Answer Comment:

However, the 'feet' and 'meter' versions of Table 2 for AC are either missing a column or the last column is mislabeled.

Document Name:

Likes: 0

Dislikes: 0

Daniel Mason - City and County of San Francisco - 5 -

Selected Answer: No

Answer Comment:

Hetch Hetchy Water and Power believes the changes recommended in the attached WECC FAC-003-4 position paper should be considered prior to the approval of FAC-003-4.

Document Name: 12-10-15 WECC Position Paper on FAC-003-4.docx

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
J. Scott Williams	City Utilities of Springfield	SPP	1,4
Jim Nail	City of Independence, Power & Light Department	SPP	3,5
John Falsey	Invenergy	NA - Not Applicable	NA - Not Applicable
John Allen	City Utilities of Springfield	SPP	1,4
Kevin Giles	Westar Energy Inc..	SPP	1,3,5,6
Louis Guidry	Cleco Corporation	SPP	1,3,5,6
Michelle Corley	Cleco Corporation	SPP	1,3,5,6
Mike Kidwell	Empire District Electric	SPP	1,3,5
Robert Hirchak	Cleco Corporation	SPP	1,3,5,6

Voter Information

Voter	Segment
Shannon Mickens	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Ryan Strom	Buckeye Power, Inc.	RFC	4
Amber Skillern	East Kentucky Power Cooperative	SERC	1,3
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5
Scott Brame	North Carolina Electric Membership Corporation	SERC	3,4,5
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1

Voter Information

Voter

Colleen Campbell

Segment

6

Entity

ACES Power Marketing

Region(s)

NA - Not Applicable

Selected Answer: No

Answer Comment:

We recommend the SDT consider adding a graph, possibly on a logarithmic scale, to clearly list the values for each elevation. The revised table is congested with the additional information and should be modified for easier readability.

Document Name:

Likes: 0

Dislikes: 0

Oshani Pathirane - Oshani Pathirane On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Selected Answer: No

Answer Comment:

Hydro One Networks Inc. does not agree with the elevation levels specified in Table 2. There are also a few minor modifications that need correction in Table 2.

Document Name:

Likes: 0

Dislikes: 0

3. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:
na

Document Name:

Likes: 0

Dislikes: 0

William Hutchison - Southern Illinois Power Cooperative - 1 -

Selected Answer:

Answer Comment:
None

Document Name:

Likes: 0

Dislikes: 0

John Falsey - Invenergy LLC - 5,6 - FRCC,MRO,WECC,TRE,NPCC,SERC,SPP,RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rob Robertson - SunEdison - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Randall Hubbard - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - FRCC,WECC,TRE,SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc..	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R. Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Voter Information

Voter

Randall Hubbard

Segment

1,3,5,6

Entity

Southern Company - Southern Company Services, Inc.

Region(s)

FRCC,WECC,TRE,SERC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter	Segment
Richard Hoag	1,3,4,5,6
Entity	**Region(s)**
FirstEnergy - FirstEnergy Corporation	RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dan Bamber - Dan Bamber On Behalf of: David Downey, ATCO Electric,1

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

In the applicability section of FAC-003-4, the Standard applies in bullet 4.2.1 to "Each overhead transmission line operated at 200 kV or higher." Please comment on whether FAC-003-4 applies to non-BES lines in addition to BES lines. For example, if a 230 kV line is excluded from the BES because it is a load serving only radial line, does FAC-003-4 apply to this line as it is a transmission line operated at over 200 kV?

Document Name:

Likes: 0

Dislikes: 0

Herb Schrayshuen - Herb Schrayshuen - 2 -

Selected Answer:

Answer Comment:

It appears that the standard is moving back to the use of the term Planning Authority. NERC's practice in standards development has been moving toward the term Planning Coordinator as the common definition. This standard shold use Planning Coordinator in a future revision before final industry approval.

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 Authority. <===== should be Planning Coorindator*

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

AEP agrees with the direction that the project team is taking, and supports their overall efforts. AEP's negative vote is driven solely by the apparent lack of equivalency between the English and Metric values that have been proposed for Table 2, and we look forward to potential corrections in the subsequent version of the draft.

Document Name:

Likes: 0

Dislikes: 0

Roger Dufresne - Hydro-Qu?bec Production - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Information

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Voter Information

Voter

Randi Heise

Segment

5

Entity

Dominion - Dominion Resources, Inc.

Region(s)

Selected Answer:

Answer Comment:

Dominion supports the additional comments of NPCC.

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer:

Answer Comment:
Hydro-Quebec TransEnergie support NPCC comments

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6

Tony Eddleman	Nebraska Public Power District	MRO	1,3,5
Amy Casucelli	Xcel Energy	MRO	1,3,5,6

Voter Information

Voter	Segment
Emily Rousseau	1,2,3,4,5,6
Entity	**Region(s)**
MRO	MRO

Selected Answer:

Answer Comment: The NSRF agrees with the associated changes.

Document Name:

Likes: 0

Dislikes: 0

Michelle Amarantos - APS - Arizona Public Service Co. - 1 -

Selected Answer:

Answer Comment:

While the proposed FAC-003-4 provides additional clearance, APS believes that there are still gaps to address. The testing was done at the EPRI testing facility but not under all weather, topography, atmosphere conditions and variances in tree species. APS is concerned these clearance distances are still too restrictive to ensure reliability of the grid. To compound the issue, these clearances are real-time observations that don't take into account line loading (sag), temperature and time of day. APS would recommend an additional 10 feet of clearance to safeguard the reliability of the grid.

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Laura Nelson - IDACORP - Idaho Power Company - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tammy Porter - Tammy Porter On Behalf of: Rod Kinard, Oncor Electric Delivery,1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:
na

Document Name:

Likes: 0

Dislikes: 0

Steven Rueckert - Western Electricity Coordinating Council - 10 -

Selected Answer:

Answer Comment:

Thank you for the opportunity to comment on the standard.

For appearance, all column widths on the tables should be the same. Values in some of the cells do not line up with the other values. This makes the table look sloppy.

I recognize that the ranges on the Metric table columns are exact translations of the 1000 foot ranges, but the numbers identifying the elevation for each column are not how entities that use the Metric System rather than the English System are going to think. No one is going to think in terms of 914.4 to 1219.2 meters. They are going to think in even numbered terms (900-1200 meters). Taking the direct translation rather than fixed, rounded terms is a slap in the face to those using the Metric System. That would be like labeling the English column 2952.7 - 3937.1 feet. The Metric column ranges should be even meters and the values in the cells adjusted accordingly.

R1 and R2 are identical in every way except the facilities that they refer to. Together they refer to all facilities. The VRFs and VSLs are also identical. I disagree with the need to separate them into two different requirements becasue the facilities in R1 are more significant. Compliance enforecement has the discretion to handle a violation differently if it is an element of an IROL or a Major WECC Path. The standard doesn't need two requirements for the same thing.

We have attached a redline version of FAC-003-4 that includes addtional suggested changes and the reasons for the suggestions.

Document Name: FAC-003-4_Results_Based_Standard_WECC Comments.docx

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:

Answer Comment:

ATC has identified the following recommended improvements for consideration by

the SDT to the draft Standard .

- Regarding the Applicability of Facilities Section 4.2.2., American Transmission Company (ATC) recommends revising the language for clarity, to read: "Each overhead transmission line operated below 200 kV identified as an element of *a Planning Horizon* IROL…"
- Similarly, ATC recommends revising the language of R1 to read: "Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s) which are either an element of *a Planning Horizon* IROL,…"
- ATC suggests updating the language of R2 to read: Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line (s) which are not either an element of *a Planning Horizon* IROL,…"
- R5 contains a grammatical error and should state: "When *an* applicable…"
- ATC recommends making updates corresponding to those above to Categories 1A, 1B, 2A, 2B, 4A, and 4B identified on pgs. 13-14: "Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of *a Planning Horizon* IROL …," "Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of *a Planning Horizon* IROL…," "Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified as an element of *a Planning Horizon* IROL…," "Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified as an element of *a Planning Horizon* IROL…," "Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified as an element of *a Planning Horizon* IROL…," and "Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified as an element of *a Planning Horizon* IROL…"
- ATC recommends updating the proposed language in the Guidelines and Technical Basis section (pg. 24) to read: "The special case is needed because the Planning Authorities may designate lines below 200 kV to become elements of *a Planning Horizon* IROL…A line operating below 200kV designated as an element of *a Planning Horizon*..."
- The Project 2010-07.1 Adjusted MVCDs per EPRI Testing section (pg. 26) needs grammatical correction: "The advisory team *was comprised of* NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulation coordination, and vegetation management…Based on these testing results conducted by EPRI, and consistent with the report filed in FERC Docket No. RM12-4-000, the gap factor used in the Gallet equation *required* adjustment from 1.3 to 1.0…"
- The Requirements R1 and R2 section (pg. 27) should be updated to read: "R1 is applicable to lines that are identified as an element of *a Planning Horizon* IROL or Major WECC Transfer Path. R2 is applicable to all other

lines that are not elements of *Planning Horizon* IROLs,... The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of *a Planning Horizon* 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 *Planning Horizon* IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of *Planning Horizon* IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant."

Document Name:

Likes: 0

Dislikes: 0

Angela Gaines - Portland General Electric Co. - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

PGE is in agreement with WECC as outlined in their position paper and is casting a "No" vote for this standard. WECC's position paper is attached.

Document Name: 12-10-15 WECC Position Paper on FAC-003-4.docx

Likes: 0

Dislikes: 0

Steve Wenke - Avista - Avista Corporation - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Information

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Voter Information

Voter

Colby Bellville

Segment

1,3,5,6

Entity

Duke Energy

Region(s)

FRCC,SERC,RFC

Selected Answer:

Answer Comment:

Duke Energy would like to point out to the SDT, that there appears to be an omission on Table 2 of the MVCD range of "over 13,000ft up to 14,000ft". The columns currently lists ranges from 12,000ft to 13,000ft, and then moves to 14,000ft to 15,000ft skipping over the 13,000 to 14,000ft range. Duke Energy recommends adding an additional column to include the omitted MVCD range.

Duke Energy would also like to point out that there are some inconsistencies with the number of decimal places that are used in Table 2 of the currently enforceable FAC-003-3. In some instances one decimal place is used (ex. 8.2ft) and others where two decimal places are used (ex. 8.33ft). We recommend that a consistent approach be used going forward regarding the minimum MVCD levels, and that all values use the same number of decimal places in Table 2.

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment:

Texas RE noticed in R1.1, the table is referenced as FAC-003-Table 2. In the VSLs, the table is referenced as FAC-003-4-Table 2. Texas RE recommends changing the requirement language to match the VSL language to eliminate confusion and clearly indicate the table for version 4 of the standard.

Texas RE noticed the VSL for R2 references FAC-003-4-Table 2 but the Requirement language itself does not. Texas RE recommends the requirement language reference Table 2 in order to be consistent with the VSL language. Should Requirement 2 language include the same phrase, "as shown in FAC-003-Table 2" with or without the "-4" reference, as Requirement 1?

Texas RE inquires: does the table in the supplemental material (titled "Comparison of spark-over……") need to be changed based on the EPRI review?

Texas RE recommends reviewing the footnotes for consistency. Footnotes 9, 10, and 11 reference Footnotes 4, 5, and 6, while Footnotes 17, 19, and 21 are identical but all include the full language of the footnote. Footnotes 18 and 20 are also identical, but footnote 20 includes the full language instead of "See footnote 18".

For example, Texas RE noticed two footnotes with similar language. On Page 8 of the Standard there is a footnote, #4, that is then referenced on Page 9 by footnote #9: "This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's or applicable Generator Owner's right to exercise its full legal rights on the ROW. "

On Page 11 in Footnote #15 there is a similar sentence to Footnote #4; "Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body."

Texas RE recommends the SDT be consistent with the language of the footnotes.

The Table 2 footnote " + Table 2- Table of MVCD…" is incorrect as the May 14, 2015. NERC Advisory did not include the 14000 to 15000 ft column.

On the Direct Current portion of Table 2, Texas RE noticed there is not a reference regarding line operated at normal voltages "other than those listed" as well. Should there be? Also, why did the SDT not extend the Direct Current portion of the Table to 15000 ft?

Texas RE recommends changing the language of R1 and R2. The Requirements should read: “to prevent encroachments of the types shown below into the MVCD of its applicable lines, operating within their Rating and all Rated Electrical Operating Conditions, which are…..” instead of “operating within its Rating and all Rated Electrical Operating Conditions of types shown below:” The current version reads as if the “types show below” is referencing Rated Electrical Operating Conditions.

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer:

Answer Comment:

The Bureau of Reclamation supports the drafting team’s proposed revisions to FAC-003-4.

Document Name:

Likes: 0

Dislikes: 0

Diana McMahon - Salt River Project - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Information

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Voter Information

Voter

Ginette Lacasse

Segment

1,3,4,5,6

Entity

Seattle City Light

Region(s)

WECC

Selected Answer:

Answer Comment:

As mentioned above we are supporting the WECC Position Paper of Dec 7, 2015 as follows:

- Correct the Functional Entity from “Planning Authority” to “Planning Coordinator”
- Although distances for AC lines are increased by 30% due to the study, there has been no increase in the distances for the DC lines, and no explanation is given. These distances should be considered for revision.
- For ease-of-use, the columns from “Over sea level up to 500 ft” and “Over 500 ft up to 1000 ft” should be combined to a single column “Over sea level up to 1000 ft”…only one cell will change by one tenth of a foot in only the 765kV voltage class.
- The elevation columns in the “meters” page of Table 2, are calculated to exactly match the elevations in feet, in the process the elevations given are un-workable. Elevations of 304.8m, 609.6m, 914.4m, etc. should be changed to 300m, 600m, 900 m. The MVCD’s (rounded to within one tenth of a foot) will not change.
- In Table 2 for Direct Current, the MVCD’s are calculated to within one hundredth of a foot – this is an un-workable level of precision.

Document Name:

Likes: 0

Dislikes: 0

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC

Group Information

Group Name: RSC without Con Edison

Group Member Name	Entity	Region	Segments
Paul Malozewski	Hydro One.	NPCC	1
Guy Zito	Northeast Power Coordinating Council	NPCC	NA - Not Applicable
Brian Shanahan	National Grid	NPCC	1
Rob Vance	New Brunswick Power	NPCC	1

Robert J. Pellegrini	United Illuminating	NPCC	1
Sylvain Clermont	Hydro Quebec	NPCC	1
Edward Bedder	Orange and Rockland Utilities	NPCC	1
Mark J. Kenny	Eversource Energy	NPCC	1
Gregory A. Campoli	NY-ISO	NPCC	2
Si Truc Phan	Hydro Quebec	NPCC	2
Randy MacDonald	New Brunswick Power	NPCC	2
David Burke	Orange and Rockland Utilities	NPCC	3
Wayne Sipperly	New York Power Authority	NPCC	4
Connie Lowe	Dominion Resources Services	NPCC	4
David Ramkalawan	Ontario Power Generation	NPCC	4
Glen Smith	Entergy Services	NPCC	4
Brian O'Boyle	Con Edison	NPCC	5
Brian Robinson	Utility Services	NPCC	5
Bruce Metruck	New York Power Authority	NPCC	6
Alan Adamson	New York State Reliability Council	NPCC	7
Kathleen M. Goodman	ISO-New England	NPCC	2
Helen Lainis	Independent Electricity System Operator	NPCC	2
Michael Jones	National Grid	NPCC	3
Silvia Parada Mitchell	NextEra Energy	NPCC	4

Voter Information

Voter	Segment
Ruida Shu	1,2,3,4,5,6,7
Entity	**Region(s)**
Northeast Power Coordinating Council	NPCC

Selected Answer:

Answer Comment:

There are inconsistency with the use of terms “Planning Coordinator” and “Planning Authorities”.

NERC has been transitioning from the term planning authority to the term Planning Coordinator over the last several years.

But in this standard it has recently been change back to Planning Authority. We believe that this is the wrong designation.

Document Name:

Likes: 0

Dislikes: 0

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Patricia Robertson - BC Hydro and Power Authority - 1 -

Group Information

Group Name: BC Hydro

Group Member Name	Entity	Region	Segments
Patricia Robertson	BC Hydro and Power Authority	WECC	1
Venkataramakrishnan Vinnakota	BC Hydro and Power Authority	WECC	2
Pat G. Harrington	BC Hydro and Power Authority	WECC	3
Clement Ma	BC Hydro and Power Authority	WECC	5

Voter Information

Voter	Segment
Patricia Robertson	1
Entity	**Region(s)**
BC Hydro and Power Authority	

Selected Answer:

Answer Comment:

BC Hydro recommends changing Planning Authority to Planning Coordinator to align with current terminology.

Document Name:

Likes: 0

Dislikes: 0

Peter Heidrich - Florida Reliability Coordinating Council - 10 -

Selected Answer:

Answer Comment:

The SDT has established inconsistency with the use of the designations “Planning Coordinator” and “Planning Authority”. NERC has been transitioning from the term Planning Authority to the term Planning Coordinator, but in this standard revision the Planning Coordinator designation has been changed back to Planning Authority.

Document Name:

Likes: 0

Dislikes: 0

Daniel Mason - City and County of San Francisco - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
J. Scott Williams	City Utilities of Springfield	SPP	1,4

Jim Nail	City of Independence, Power & Light Department	SPP	3,5
John Falsey	Invenergy	NA - Not Applicable	NA - Not Applicable
John Allen	City Utilities of Springfield	SPP	1,4
Kevin Giles	Westar Energy Inc..	SPP	1,3,5,6
Louis Guidry	Cleco Corporation	SPP	1,3,5,6
Michelle Corley	Cleco Corporation	SPP	1,3,5,6
Mike Kidwell	Empire District Electric	SPP	1,3,5
Robert Hirchak	Cleco Corporation	SPP	1,3,5,6

Voter Information

Voter	Segment
Shannon Mickens	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer:

Answer Comment:

Page 2 of the Standard….second line of the purpose definition. We would suggest to the drafting team to capitalize ‘vegetation’ since it is a defined term in the NERC Glossary of Terms.

Page 2 of the Standard….In section 4.1.1.1 of the Applicable Transmission Owner. We would suggest to the drafting team to not capitalize ‘Transmission Facilities’ since it is not a defined term in the NERC Glossary of Terms.

Page 2 of the Standard….In section 4.1.2 of the Applicable Generator Owner. We would suggest to the drafting team to not capitalize ‘Facilities’ since it is not a defined term in the NERC Glossary of Terms. However, the term‘Facility’ is defined.

Page 2 of the Standard….In section 4.2.1, 4.2.2, 4.2.3, 4.2.4 of Facilities. We would suggest to the drafting team to capitalize ‘transmission line’ since it is a defined term in the NERC Glossary of Terms.

Page 3 of the Standard….In section 4.3.1 of Generation Facilities (first line). We would suggest to the drafting team to capitalize ‘transmission line’ since it is a defined term in the NERC Glossary of Terms.

Page 3 of the Standard….last paragraph of the Background (first, second, and third line). We would suggest to the drafting team to capitalize ‘reliability standard

(s)' since it is a defined term in the NERC Glossary of Terms.

Page 4 of the Standard… bullets 2, 3, 5.). We would suggest to the drafting team to capitalize 'vegetation' since it is a defined term in the NERC Glossary of Terms. Also, we make the same suggestions in the last two paragraphs for the same term.

Page 4 of the Standard….last paragraph. We would suggest to the drafting team to capitalize 'transmission line' since it is a defined term in the NERC Glossary of Terms.

Page 5 of the Standard…..Requirement R1 (second line). We would suggest to the drafting team to capitalize 'vegetation' since it is a defined term in the NERC Glossary of Terms. Additionally, we suggest some alternative language for Requirement R1 to define or identify how these the elements of an IROL and elements of a Major WECC Transfer Path are determined. The suggested language as followed: "Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path that are determined by a particular study; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below".

Page 6 of the Standard….In sections 1.2, 1.3,1. 4 of Requirement R1. We would suggest to the drafting team to capitalize 'vegetation' since it is a defined term in the NERC Glossary of Terms.

Page 6 of the Standard…..Measurement M1. We would suggest to the drafting team to capitalize 'vegetation' since it is a defined term in the NERC Glossary of Terms.

Page 6 of the Standard….. Requirement R2. We would suggest to the drafting team to capitalize 'vegetation' since it is a defined term in the NERC Glossary of Terms. Also, we make the same suggestions in sections 2.2, 2.3, 2.4 for the same term.

Page 7 of the Standard…..Measurement M2. We would suggest to the drafting team to capitalize 'vegetation' since it is a defined term in the NERC Glossary of Terms.

Page 7 of the Standard….. Requirement R3 (line 3). We would suggest to the drafting team to capitalize 'vegetation' since it is a defined term in the NERC Glossary of Terms.

Page 8 of the Standard….. Requirement R6 (line 2). We would suggest to the drafting team to capitalize 'transmission line' since it is a defined term in the NERC Glossary of Terms.

Page 8 of the Standard….. Measurement R6 (line 2). We would suggest to the

drafting team to capitalize 'transmission line' since it is a defined term in the NERC Glossary of Terms.

Document Name:

Likes: 0

Dislikes: 0

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Ryan Strom	Buckeye Power, Inc.	RFC	4
Amber Skillern	East Kentucky Power Cooperative	SERC	1,3
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5
Scott Brame	North Carolina Electric Membership Corporation	SERC	3,4,5
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1

Voter Information

Voter	Segment
Colleen Campbell	6
Entity	**Region(s)**
ACES Power Marketing	NA - Not Applicable

Selected Answer:

Answer Comment:

(1) We question the modification from Planning Coordinator to Planning Authority. The NERC Glossary defines the PC, but not the PA. If the SDT is striving for consistency with FAC-014, we suggest developing a SAR to replace the outdated reference of the Planning Authority with the current Planning Coordinator term. It is surprising that the standards still have two terms for a single registered function. The Functional Model Working Group is conducting a review of the NERC Functional Model, and we suggest that the SDT discuss this change with them for guidance going forward.

(2) The timelines of the Implementation Plan are reasonable. However, we recommend copying the same language from the standard to the Implementation Plan for consistency.

(3) We also find Section C. Compliance, Section 1.2 Evidence Retention, second bullet, redundant, as “unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation” is already listed at the beginning of the section.

(4) We thank you for this opportunity to comment.

Document Name:

Likes: 0

Dislikes: 0

Oshani Pathirane - Oshani Pathirane On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Selected Answer:

Answer Comment:

While Hydro One Networks Inc. feels that the standard needs a few minor modifications and corrections, we generally support the intent of the standard. Hydro One Networks Inc. further supports the comments provided by the NPCC. Hydro One Networks Inc. agrees with the NPCC in that the “Planning Coordinator”, as opposed to the “Planning Authority”, should be an applicable functional entity for the standard.

Document Name:

Likes: 0

Dislikes: 0

Standard Development Timeline

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

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	August 19, 2015
SAR posted for comment	August 24, 2015

Anticipated Actions	Date
45-day formal comment period with ballot	October 2015
10-day final ballot	January 2016
NERC Board (Board) adoption	February 2016

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Transmission Vegetation Management
2. **Number:** FAC-003-4
3. **Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.
4. **Applicability:**

4.1. Functional Entities:

4.1.1. Applicable Transmission Owners

4.1.1.1. Transmission Owners that own Transmission Facilities defined in 4.2.

4.1.2. Applicable Generator Owners

4.1.2.1. Generator Owners that own generation Facilities defined in 4.3

4.2. Facilities: Defined below (referred to as "applicable lines"),

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 Authority.

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

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

4.3. Generation Facilities: Defined below (referred to as "applicable lines"):

4.3.1. Overhead transmission lines that (1) extend greater than one mile or 1.6 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) do

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Commented [MB2]: This standard applies to all transmission outside the switchyard or substation as identified in 4.2.1 through 4.2.3.

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not have a clear line of sight[3] from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and are:

4.3.1.1. Operated at 200kV or higher; or

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

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

5. Effective Date: See Implementation Plan.

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

a) **Performance-based** - defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome?*

b) **Risk-based** - preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?*

c) **Competency-based** - defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?*

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

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

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

- 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, will reduce and manage this risk.

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.

Commented [MB4]: "any kind of land" is referring to who owns the land. Easement refers to certain rights to locate a line on the land.

Commented [MB5]: It is already stated "any kind of land" the rest is redundant.

Deleted: whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee,

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However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

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

B. Requirements and Measures

R1. Each applicable Transmission Owner(TO) and applicable Generator Owner(GO) shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable lines operating within their Rating and all Rated Electrical Operating Conditions of the types shown below[4] *[Violation Risk Factor: High] [Time Horizon: Real-time]*

1.1 An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,[5]

1.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[6]

1.3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[7],

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Deleted: which are either an element of an IROL, or an element of a Major WECC Transfer Path

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Commented [MB8]: Is this intentionally excluding a situation where the line is overloaded and sagging…or where it is operating below its rated voltage?

Commented [MB9]: R1 is written to "Prevent encroachments" while 1.1 – 1.4 are written in past tense…a violation only occurs if an encroachment is seen or caused an outage. So inadequate management that will result in an outage as soon as the wind blows a little or the conductor heats up is not addressed.

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

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

[6] 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.

[7] *Id.*

1.4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.[8]

M1. Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. 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)

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R2. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[9] *[Violation Risk Factor: High] [Time Horizon: Real-time]*

Commented [MB12]: R1 covers lines that "are" R2 covers lines that "are not" we could simply use one requirement…unless the intent is to have different VSL's or VRF's…however they are the same. We could eliminate R2 and just have R1 cover both.

2.1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,[10]

2.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[11]

2.3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,[12]

2.4. An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage.[13]

M2. Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. 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)

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R3. Each applicable Transmission Owner and applicable Generator Owner shall have a annual vegetation work plan it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

Commented [MB13]: See wording from R7 – annual vegetation work plan

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[8] *Id.*
[9] See footnote 4.
[10] See footnote 5.
[11] See footnote 6.
[12] *Id.*
[13] *Id.*

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.

M3. Evidence may include copies of the annual vegetation work planthat demonstrates that the applicable Transmission Owner and applicable Generator Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

R4. Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when they have confirmed the existence of a vegetation condition could encroach on the MVCD due to a possible change in loading, wind or weather. *[Violation Risk Factor: Medium] [Time Horizon: Real-time].*

M4. Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

R5. When an applicable Transmission Owner and applicable Generator Owner is constrained from performing vegetation work on an applicable line, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M5. Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

R6. Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines at least once per

Commented [MB15]: It seems these ratings are getting at…the line is designed to withstand movement and sagging due to electrical load, wind, ice, temperature, etc.

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calendar year and with no more than 18 calendar months between inspections on the same ROW[14] [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M6. Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Aacceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

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R7. Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

Commented [MB17]: Consider using this term in other requirements.

7.1. Change in expected growth rate/environmental factors

7.2. Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner[15]

7.3. Rescheduling work between growing seasons

7.4. Crew or contractor availability/Mutual assistance agreements

7.5. Identified unanticipated high priority work

7.6. Weather conditions/Accessibility

7.7. Permitting delays

7.8. Land ownership changes/Change in land use by the landowner

7.9. Emerging technologies

M.7 .Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Acceptable

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

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

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:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

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

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

- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, for three calendar years.
- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- If an applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

1.3. Compliance Monitoring and Enforcement Program
As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information

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

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

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

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

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

Violation Severity Levels (Table 1)

R #	Table 1: Violation Severity Levels (VSL)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following: • *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.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and a

			transfer path and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	vegetation-related Sustained Outage was caused by one of the following: • *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*
R3.		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity's applicable lines. (Requirement R3, Part 3.2)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines. Requirement R3, Part 3.1)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity's applicable lines.
R4.			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority	The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority

			for that applicable line, but there was intentional delay in that notification.	for that applicable line.
R5.				The responsible entity did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6.	The responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7.	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Variances

None.

E. Associated Documents

- Link to FAC-003-4 Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	January 20, 2006	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.	New
1	April 4, 2007	Regulatory Approval - Effective Date	New
2	November 3, 2011	Adopted by the NERC Board of Trustees	New
2	March 21, 2013	FERC Order issued approving FAC-003-2 (Order No. 777) FERC Order No. 777 was issued on March 21, 2013 directing NERC to "conduct or contract testing to obtain empirical data and submit a report to the Commission providing the results of the testing."[16]	Revisions
2	May 9, 2013	Board of Trustees adopted the	Revisions

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

		modification of the VRF for Requirement R2 of FAC-003-2 by raising the VRF from "Medium" to "High."	
3	May 9, 2013	FAC-003-3 adopted by Board of Trustees	Revisions
3	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-003-3. This standard becomes enforceable on July 1, 2014 for Transmission Owners. For Generator Owners, R3 becomes enforceable on January 1, 2015 and all other requirements (R1, R2, R4, R5, R6, and R7) will become enforceable on January 1, 2016.	Revisions
3	November 22, 2013	Updated the VRF for R2 from "Medium" to "High" per a Final Rule issued by FERC	Revisions
3	July 30, 2014	Transferred the effective dates section from FAC-003-2 (for Transmission Owners) into FAC-003-3, per the FAC-003-3 implementation plan	Revisions
4	Projected initial posting October 2015	Adjusted MVCD values in Table 2 for alternating current systems, consistent with findings reported in report filed on August 12, 2015 in Docket No. RM12-4-002 consistent with FERC's directive in Order No. 777, and based on empirical testing results for flashover distances between conductors and vegetation.	Revisions

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[17]

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)+	(AC) Maximum System Voltage (kV)[18]	MVCD feet Over sea level up to 500 ft	MVCD feet Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft	MVCD feet Over 11000 ft up to 12000 ft	MVCD feet Over 12000 ft up to 13000 ft	MVCD fee Ove 14000 up t 15000
765	800	11.6ft	11.7ft	11.9ft	12.1ft	12.2ft	12.4ft	12.6ft	12.8ft	13.0ft	13.1ft	13.3ft	13.5ft	13.7ft	13.9ft	14.0
500	550	7.0ft	7.1ft	7.2ft	7.4ft	7.5ft	7.6ft	7.8ft	7.9ft	8.1ft	8.2ft	8.3ft	8.5ft	8.6ft	8.8ft	8.9
345	362	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft
287	302	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft	5.8ft	5.9ft	6.1ft	6.2ft	6.3ft	6.4ft	6.5ft	6.6ft	6.7ft
230	242	4.0ft	4.1ft	4.2t	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft
161*	169	2.7ft	2.7ft	2.8ft	2.9ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft	3.3ft	3.3ft	3.4ft	3.5ft	3.6ft	3.6ft
138*	145	2.3ft	2.3ft	2.4ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft	2.7ft	2.8ft	2.8ft	2.9ft	3.0ft	3.0ft	3.1ft
115*	121	1.9ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.1ft	2.2ft	2.2ft	2.3ft	2.3ft	2.4ft	2.5ft	2.5ft	2.6ft
88*	100	1.5ft	1.5ft	1.6ft	1.6ft	1.7ft	1.7ft	1.8ft	1.8ft	1.8ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.1ft
69*	72	1.1ft	1.1ft	1.1ft	1.2ft	1.2ft	1.2ft	1.2ft	1.3ft	1.3ft	1.3ft	1.4ft	1.4ft	1.4ft	1.5ft	1.5ft

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

\+ *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the NERC Advisory posted on May 14, 2015.*

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Commented [MB18]: Pretty much impossible to have an applible line above 14000 feet

Commented [MB19]: Missing the 13000 to 14000 column

Commented [MB20]: These entrie are out of line with the others

[17] 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.

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

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[19]

For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)+	(AC) Maximum System Voltage (kV)[20]	MVCD meters Over sea level up to 152.4 m	MVCD meters Over 152.4 m up to 304.8 m 300	MVCD meters Over 304.8 m up to 609.6m 600	MVCD meters Over 609.6m up to 914.4m 900	MVCD meters Over 914.4m up to 1219.2m 1200	MVCD meters Over 1219.2m up to 1524m 1500	MVCD meters Over 1524 m up to 1828.8 m 1800	MVCD meters Over 1828.8m up to 2133.6m 2100	MVCD meters Over 2133.6m up to 2438.4m 2400	MVCD meters Over 2438.4m up to 2743.2m 2700	MVCD meters Over 2743.2m up to 3048m 3000	MVCD meters Over 3048m up to 3352.8m 3300	MVCD meters Over 3353m up to 3657m 3600	MVCD meters Over 3657m up to 3962m 3900	MVCD meters Over 3692m up to 4 42
765	800	3.6m	3.6m	3.6m	3.7m	3.7m	3.8m	3.8m	3.9m	4.0m	4.0m	4.1m	4.1m	4.2m	4.2m	4.3
500	550	2.1m	2.2m	2.2m	2.3m	2.3m	2.3m	2.4m	2.4m	2.5m	2..5m	2.5m	2.6m	2.6m	2.7m	2.7
345	362	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m	1.7m	1.7
287	302	1.6m	1.6m	1.7m	1.7m	1.7m	1.7m	1.8m	1.8m	1.9m	1.9m	1.9m	2.0m	2.0m	2.0m	2.1m
230	242	1.2m	1.3m	1.3m	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m
161*	169	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m	1.0m	1.0m	1.0m	1.1m	1.1m	1.1m
138*	145	0.7m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	0.9m
115*	121	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8
88*	100	0.4m	0.4m	0.5m	0.5m	0.5m	0.5m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m
69*	72	0.3m	0.3m	0.3m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.5m	0.5

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

+ *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the NERC Advisory posted on May 14, 2015.*

Commented [MB22]: Precision to tenths of meter is not necessary . We can round off these elevations to workable numbers without changing the distances.

Commented [MB21]: This extra column up to 500 ft is not needed – combine with the 1000 ft. column. It only changes two distances by 1/10 ft each.

Commented [MB23]: Out of line

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[19] 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.

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

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[21]

For **Direct Current** Voltages feet (meters)

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

Commented [MB25]: Unnecessary precision

Commented [MB26]: See comments for prvious tables

Commented [MB27]: Precision to hundredths of meters is not needed or workable

[21] 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.

Guideline and Technical Basis

Effective dates:

The Compliance section is standard language used in most NERC standards to cover the general effective date and covers the vast majority of situations. A special case covers effective dates for (1) lines initially becoming subject to the Standard, (2) lines changing in applicability within the standard.

The special case is needed because the Planning Authorities 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 Authority in 2015 may identify a line to have that designation beginning in PY 2025, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. 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.

Date that Planning Study is completed	PY the line will become an IROL element	Date 1	Date 2	Effective Date The latter of Date 1 or Date 2
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

Defined Terms:

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

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

Explanation of the derivation 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. The table is based on empirical testing data from EPRI as requested by FERC in Order No. 777.

Commented [MB28]: Recommend that we provide the actual equations so users can see how the variable inputs apply.

Project 2010-07.1 Adjusted MVCDs per EPRI Testing:
In Order No. 777, FERC directed NERC to undertake testing to gather empirical data validating the appropriate gap factor used in the Gallet equation to calculate MVCDs, specifically the gap factor for the flash-over distances between conductors and vegetation. See, Order No. 777, at P 60. NERC engaged industry through a collaborative research project and contracted EPRI to complete the scope of work. In January 2014, NERC formed an advisory group to assist with developing the scope of work for the project. This team provided subject matter expertise for developing the test plan, monitoring testing, and vetting the analysis and conclusions to be submitted in a final report. The advisory team comprised NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulation coordination, and vegetation management. The testing project commenced in April 2014 and continued through October 2014 with the final set of testing completed in May 2015. Based on these testing results conducted by EPRI, and consistent with the report filed in FERC Docket No. RM12-4-000, the gap factor used in the Gallet equation required adjustment from 1.3 to 1.0. This resulted in increased MVCD values for all alternating current system voltages identified. The adjusted MVCD values, reflecting the 1.0 gap factor, are included in Table 2 of version 4 of FAC-003.

The air gap testing completed by EPRI per FERC Order No. 777 established that trees with large spreading canopies growing directly below energized high voltage conductors create the

greatest likelihood of an air gap flash over incident and was a key driver in changing the gap factor to a more conservative value of 1.0 in version 4 of this standard.

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

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant.

Commented [MB29]: Their Violation Risk Factors should be different.or the VSLs should be different. As drafted the two requirements, VRFs, and VSLs are identical.

Compliance enforecement has the discretion to handle a violation differently if it is an lement of an IROL or a Major WECC Path. The standard doesn't need two requirements for the same thing.

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.

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

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

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to

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

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

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

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

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

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

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*

2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

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

Commented [MB30]: This gets to the point that we should be saying the vegetation cannot encroach on the area defined by all possible conductor movement plus the MVCD around that area.

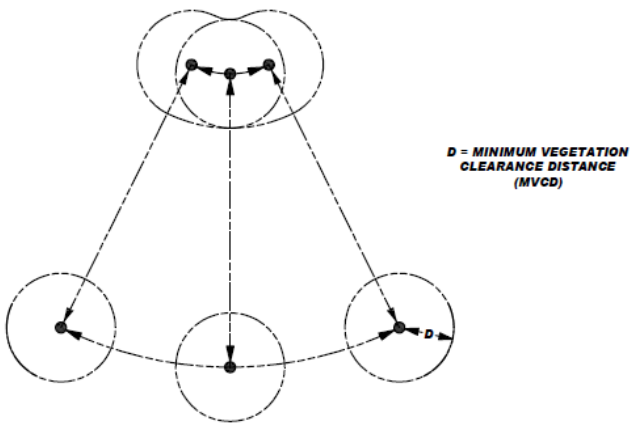

Figure 1

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

Requirement R4:
R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching

authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

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

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

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

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

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

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

applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

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

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

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

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

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once

during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. The "Low VSL" for R6 would apply in this example.

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

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

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

In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner's or applicable Generator Owner's easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces

the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

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

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

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.

Commented [MB31]: Didn't this capacitor switching just get thrown out in the previous paragraph?

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.

Commented [MB32]: Why is this used rather than 1.5 in the previous paragraph?

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.

Since no empirical data for spark over distances to live vegetation existed at the time version 3 was developed, the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

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

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

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

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

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

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

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

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

Supplemental Material

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

Rationale for R3:
The documentation provides a basis for evaluating the competency of the applicable Transmission Owner's or applicable Generator Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-within MVCD of wire conflicts under all Ratings and all Rated Electrical Operating Conditions.

Rationale for R4:
This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

Rationale for R5:
Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

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

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

Rationale for R6:
Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

Supplemental Material

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.

WECC Position Paper for the initial ballot and non-binding poll of Project 2010-07.1 - FAC-003-4 Transmission Vegetation Management

Being balloted December 7-16, 2015

NERC is conducting a formal comment period and an initial ballot for FAC-003-4 Transmission Vegetation Management. The ballot is open December 7 - 16, 2015.

Members of the Project 2010-07.1 Ballot Pool **are encouraged to vote NO** because the posted version requires further corrections and revision.

Background Information

In FERC Order No. 777, the Commission directed NERC to "conduct or contract testing to obtain empirical data and submit a report to the Commission providing the results of the testing." NERC retained the Electric Power Research Institute (EPRI) to conduct testing to support appropriate Minimum Vegetation Clearance Distances (MVCDs) specified in NERC Reliability Standard FAC-003-3. The MVCDs in the Standard are calculated based on application of the Gallet equation which incorporates a gap factor that reflects the shape of objects that may flash over to the line. The preliminary test result findings determined that the gap factor applied in the Gallet equation requires adjustment. The adjustment will increase MVCDs for all alternating current system voltages covered by Table 2 of the Standard.

Summary of Changes

Revisions from FAC-003-3 reflected in FAC-003-4 include:

- As a result of the studies, the Minimum Vegetation Clearance Distances have been increased by some 30%.
- Table 2, which contains MVCD's at different elevations above sea level, has been expanded to cover line elevations up to 15,000 ft.
- In the Functional Entities section, the term **Planning Coordinator** was inadvertently changed to **Planning Authority.**
- Other Miscellaneous Changes

WECC Review of Changes

Our review indicates that while generally acceptable, the proposed changes need further work before the standard is ready for approval. It is also noted that the increased distances resulting from the EPRI study are substantial and should be considered as such in the voting process. In summary, the following changes should be made before approval:

- Correct the Functional Entity from "Planning Authority" to "Planning Coordinator"

- The added columns in Table 2 for vegetation management over 12,000ft are superfluous and not needed.
- Although not needed, the column for 14,000 to 15,000 is inadvertently skipped.
- Table 2 – (meters) contains typographical errors; A) for Over 2133.6 m, 345kV MVCD should be 1.5, not .5m; and B) for Over 2133.6 m, 115kV MVCD should be 0.7, not .07m,
- Although distances for AC lines are increased by 30% due to the study, there has been no increase in the distances for the DC lines, and no explanation is given. These distances should be considered for revision.
- For ease-of-use, the columns from "Over sea level up to 500 ft" and "Over 500 ft up to 1000 ft" should be combined to a single column "Over sea level up to 1000 ft"…only one cell will change by one tenth of a foot in only the 765kV voltage class.
- The elevation columns in the "meters" page of Table 2, are calculated to exactly match the elevations in feet, in the process the elevations given are un-workable. Elevations of 304.8m, 609.6m, 914.4m, etc. should be changed to 300m, 600m, 900 m. The MVCD's (rounded to within one tenth of a foot) will not change.
- In Table 2 for Direct Current, the MVCD's are calculated to within one hundredth of a foot – this is an un-workable level of precision.

For these reasons WECC will be voting NO – and we are encouraging others to vote against approval of the FAC-003-4 revision.

A complete copy of the proposed standard and associated materials can be viewed at: http://www.nerc.com/pa/Stand/Pages/Project-2010-07-1-Vegetation-Management.aspx

Voting

The NERC Standards Processes Manual requires that for a negative vote to be counted in the determination of consensus, negative ballots be accompanied by comments explaining the reason for the negative vote. If you vote no, in addition to providing a reason, you should also suggest modifications that would make the standard acceptable. You may provide comments using the electronic form available from the project page identified above.

A non-binding poll for the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) **will not be conducted** due to the fact that only non-substantive changes were made to the requirements, and no changes made to the VRFs and VSLs.

All WECC entities that are registered in the Project 2010-07.1 Vegetation Management Ballot Pool are urged to cast their ballots prior to the close of the ballot period on December 16, 2015.

If you do not wish to cast either an affirmative or negative vote, you are encouraged to cast an abstention to ensure that a quorum is reached.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project Name: 2010-07.1 Vegetation Management | FAC-003-4

Comment Period Start Date: 10/30/2015

Comment Period End Date: 12/16/2015

Associated Ballots: 2010-07.1 Vegetation Management FAC-003-4 IN 1 ST

There were 37 responses, including comments from approximately 123 different people from approximately 89 different companies representing 8 of the 10 Industry Segments as shown on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Howard Gugel (via email) or at (404) 446-9693.

Questions

1. Do you agree with the FAC-003-4 table 2 MVCD values? If not, please provide your response below.

2. Do you agree with modifying the elevation levels in table 2 to go up to 15,000 feet and 4,267 meters? If not, please provide your response below.

3. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

The Industry Segments are:

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

1. Do you agree with the FAC-003-4 table 2 MVCD values? If not, please provide your response below.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

William Hutchison - Southern Illinois Power Cooperative - 1 -

Selected Answer: Yes

John Falsey - Invenergy LLC - 5,6 - FRCC,MRO,WECC,TRE,NPCC,SERC,SPP,RFC

Selected Answer: Yes

Rob Robertson - SunEdison - 5 -

Selected Answer: Yes

Randall Hubbard - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - FRCC,WECC,TRE,SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc..	SERC	1

John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R. Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Selected Answer: Yes

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Selected Answer: Yes

Dan Bamber - Dan Bamber On Behalf of: David Downey, ATCO Electric, 1

Selected Answer: Yes

Herb Schrayshuen - Herb Schrayshuen - 2 -

Selected Answer:	No
Answer Comment:	The tables are missing columns (or the headers are wrong) and have some number transpositions. In the english (ft) version of the table the range between 13000' and 14000' is missing. Additionaly the rounding mathematics used to generate the tables may not be the most conservative. For clearances one should round up in all instances. There is no issue with the underlying clearance numbers that resulted from the laboratory Testing. The issue is with the translation into the standard. It appears some more quality control and independent review should have been applied.
Response:	**Thank you for your comments. The team has made adjustments to the proposed standard by 1) adding the 13000-14000 ft (and corresponding Metric column) to Table 2, 2) corrected transpositions in the headings in Table 2, and 3) has decided to remain with conventional rounding methodology after consideration. .**

Thomas Foltz - AEP - 5 -

Selected Answer:	No
Answer Comment:	While AEP does not object to the newly-proposed English values in Table 2, these values are not equivalent to the metric values provided in the same table. AEP requests that the drafting team review both the English and Metric values, and provide corrections as necessary.
Response:	**Thank you for your comments. The team has reviewed the values and consulted with EPRI to ensure that the Metric and English values are coordinated.**

Roger Dufresne - Hydro-Qu?bec Production - 5 -

Selected Answer: No

Answer Comment: See comments from TransEnergie.

Response: **Thank you. Please refer to the TransEnergie section.**

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Selected Answer: Yes

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: Yes

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5
Amy Casucelli	Xcel Energy	MRO	1,3,5,6

Selected Answer: Yes

Michelle Amarantos - APS - Arizona Public Service Co. - 1 -

Selected Answer: Yes

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Laura Nelson - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: Yes

Tammy Porter - Tammy Porter On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Steven Rueckert - Western Electricity Coordinating Council - 10 -

Selected Answer: No

Answer Comment: There are several typos in the table. In the "over 2133.6 m to 2438.4 m" column, the cell for 345 kV should be 1.5m, not .5m and the cell for 115 kV should be 0.7m, not .07m.

The added columns on the English table are missing the 13,000-14,000 ft range. The added columns on the Metric table stop at 14000 ft. The 14000-15000 ft column is not there. The two tables are inconsistent.

MVCD in the DC table did not change. Is this correct?

Response:

Thank you for comments. The team has corrected the typographical errors noted in your comments in the current proposed standard. The team has also added the 13000-14000 foot (and corresponding Metric) columns to Table 2. Finally, the values in the DC table did not change as they were not included in the scope of the project.

The additional comments regarding the requirements language in FAC-003 are beyond the scope of the project, but they will be retained for the next periodic review of the FAC-003 standard.

In regards to the values of 12000 feet and greater, the team consensus is that it is possible for facilities to be present at this altitude in North America.
The team agrees that the under 500 foot column can be combined with the 500-1000 foot column, and has made the adjustment in the current draft of the standard. The team also agrees that a tenth of a meter level of detail in the meters column headings is not necessary and has adjusted the current draft of the standard.

The DC values in table 2 were out of the scope of the project.

The values in Table 2 have been calculated based on the Gallet equation. For additional information on the actual equation, please see the FAC-003-2 Technical Reference Document, Appendix 1, available at (http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=12845997**).**

The transient over-voltage values have been contained in FAC-003 as either an Attachment or Supplemental Material since FAC-003-2 and, to the best of our

knowledge are proper and correct. There may be some confusion in the wording presenting these values but it is clear that the Supplemental Materials is stating a TOV value of 1.4 is a realistic maximum for use in this standard for system voltages of 362 kV and above.

While some of your comments refer to areas outside the scope of the project, they will be retained for the next periodic review of the FAC-003 standard.

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Angela Gaines - Portland General Electric Co. - 1,3,5,6 - WECC

Selected Answer: No

Answer Comment: Please see WECC's position paper for details

Response: **Please refer to the response to WECC's comments.**

Steve Wenke - Avista - Avista Corporation - 5 -

Selected Answer: No

Answer Comment: The following is an excerpt from the WECC position paper:

In summary, the following changes should be made before approval:

	· Correct the Functional Entity from "Planning Authority" to "Planning Coordinator" · The added columns in Table 2 for vegetation management over 12,000ft are superfluous and not needed. · Although not needed, the column for 14,000 to 15,000 is inadvertently skipped. · Table 2 – (meters) contains typographical errors; A) for Over 2133.6 m, 345kV MVCD should be 1.5, not .5m; and B) for Over 2133.6 m, 115kV MVCD should be 0.7, not .07m, · Although distances for AC lines are increased by 30% due to the study, there has been no increase in the distances for the DC lines, and no explanation is given. These distances should be considered for revision. · For ease-of-use, the columns from "Over sea level up to 500 ft" and "Over 500 ft up to 1000 ft" should be combined to a single column "Over sea level up to 1000 ft"…only one cell will change by one tenth of a foot in only the 765kV voltage class. · The elevation columns in the "meters" page of Table 2, are calculated to exactly match the elevations in feet, in the process the elevations given are un-workable. Elevations of 304.8m, 609.6m, 914.4m, etc. should be changed to 300m, 600m, 900 m. The MVCD's (rounded to within one tenth of a foot) will not change. · In Table 2 for Direct Current, the MVCD's are calculated to within one hundredth of a foot – this is an un-workable level of precision.
Response:	**Please refer to the response to WECC's comments.**

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Selected Answer: Yes

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment: Texas RE noticed the following:

• There is not an "Over 13000 ft up to 14000 ft" column provided. Should there be?

• There is an incorrect value in the MVCD meters table in the last two columns. One column references "….up to 3962m" and the final column references "Over 3692 m…." so there appears to be transposed values

• On Table 2, there is no column for Over 13000 ft up to 14000 ft. The values in the "Over 14000 ft up to 15000 ft" within the Standard match the values of the "Over 13,000 ft up to 14,000 ft" values in the May 14, 2015 Industry Advisory. Is that correct? Based on the nature of the data (a general increase for most, if not all, 1000

ft elevation increase) it does not appear reasonable.

• It does not appear that there is consistency in the values. When you review the voltage levels increasing (e.g. 230 kV to 287 kV) it appears that the MVCD increase (e.g., at "sea level up to 500 ft" the MVCD increase from 4.0 ft to 5.2 ft). The increasing pattern appears to not be followed when it reaches the 345 kV level. The MVCD actually decreases when compared to a 287 kV level. Why does that occur? Was there a different parameter used in the derivation of Gallet's equation for the 345 kV level? Ascertaining the correct value for the 345 kV level is highly critical for the ERCOT Interconnection (in both measurement type versions of the table.)

• Similar to the comment above, the MVCD for 345 kV lines from 2133.6m to 2438.4m is .5m, which is less than the MVCD of 1.5m and 1.6m for the altitudes immediately before and after in the table. This appears to be a typo and the MVCD for 345 kV lines 2133.6m to 2438.4m should be 1.5m.

• Table 2 for AC Voltages does not include lines at altitudes between 3352.8m and 3353m.

• There appears to be an inconsistency in the "meter" version of Table 2. The "older columns" have decimal point step increases (e.g. "Over 2133.6m up to 2438.4m") that are carried over to the next columns as a starting point (e.g. "Over 2438.4m up to…."). The new columns do not utilize the same formatting.

Response:

Thank you for your comments. The team has reviewed and addressed the comments as follows:

1. **The team has added the 13000-14000 foot (and corresponding Metric) columns to the current draft standard.**

2. **The team has corrected the transposed figures in the current draft standard.**
3. **See response above regarding corrections made.**
4. **The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to p.31 in the supplemental materials for additional information.**
5. **This was a typographical error. The missing "1" has been added in the current draft of the standard.**
6. **See response 1 above.**
7. **The column headings in the Metric table have been rounded up to the nearest meter for consistency**

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Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: Yes

Diana McMahon - Salt River Project - 1,3,5,6 - WECC

Selected Answer: No

Answer Comment: SRP appreciates the opportunity to review and comment on the adjustments to the standard. We support the work of the drafting team, but request a review and revision of the tables to reflect issues identified in the WECC position paper including:

- The column for 14,000 to 15,000 is inadvertently skipped.
- Table 2 – (meters) contains typographical errors; A) for Over 2133.6 m, 345kV MVCD should be 1.5, not .5m; and B) for Over 2133.6 m, 115kV MVCD should be 0.7,

not .07m,

• Although distances for AC lines are increased by 30% due to the study, there has been no increase in the distances for the DC lines, and no explanation is given. These distances should be considered for revision.

• For ease-of-use, the columns from "Over sea level up to 500 ft" and "Over 500 ft up to 1000 ft" should be combined to a single column "Over sea level up to 1000 ft"…only one cell will change by one tenth of a foot in only the 765kV voltage class.

• The elevation columns in the "meters" page of Table 2, are calculated to exactly match the elevations in feet, in the process the elevations given are un-workable. Elevations of 304.8m, 609.6m, 914.4m, etc. should be changed to 300m, 600m, 900 m. The MVCD's (rounded to within one tenth of a foot) will not change.

• In Table 2 for Direct Current, the MVCD's are calculated to within one hundredth of a foot – this is an un-workable level of precision

Response:

Thank you for your comments. The team has addressed your comments as follows:

1. **The missing column has been added in both the English and Metric sections of Table 2.**
2. **The typographical errors have been corrected in the current draft of the standard.**
3. **DC voltages are outside the scope of the project.**
4.
5. **After consideration, the team determined that it was preferable to retain both the 500 foot column and 1000 foot column.The team agrees and has rounded the meter values in the column headings to the nearest meter.**
6. **DC voltages are outside the scope of the project.**

While some of your comments refer to areas outside the scope of the project, they will be retained for the next periodic review of the FAC-003 standard.

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Selected Answer: No

Answer Comment: We support WECC Position paper, Dec 7, 2015: Table 2 – (meters) contains typographical errors; A) for Over 2133.6 m, 345kV MVCD should be 1.5, not .5m; and B) for Over 2133.6 m, 115kV MVCD should be 0.7, not .07m,

Response: **Please refer to the response to WECC's comments.**

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC

Group Name: RSC without Con Edison

Group Member Name	Entity	Region	Segments
Paul Malozewski	Hydro One.	NPCC	1
Guy Zito	Northeast Power Coordinating Council	NPCC	NA - Not Applicable
Brian Shanahan	National Grid	NPCC	1
Rob Vance	New Brunswick Power	NPCC	1
Robert J. Pellegrini	United Illuminating	NPCC	1
Sylvain Clermont	Hydro Quebec	NPCC	1
Edward Bedder	Orange and Rockland Utilities	NPCC	1
Mark J. Kenny	Eversource Energy	NPCC	1
Gregory A. Campoli	NY-ISO	NPCC	2
Si Truc Phan	Hydro Quebec	NPCC	2
Randy MacDonald	New Brunswick Power	NPCC	2
David Burke	Orange and Rockland Utilities	NPCC	3
Wayne Sipperly	New York Power Authority	NPCC	4
Connie Lowe	Dominion Resources Services	NPCC	4
David Ramkalawan	Ontario Power Generation	NPCC	4
Glen Smith	Entergy Services	NPCC	4
Brian O'Boyle	Con Edison	NPCC	5
Brian Robinson	Utility Services	NPCC	5
Bruce Metruck	New York Power Authority	NPCC	6
Alan Adamson	New York State Reliability Council	NPCC	7
Kathleen M. Goodman	ISO-New England	NPCC	2
Helen Lainis	Independent Electricity System Operator	NPCC	2
Michael Jones	National Grid	NPCC	3
Silvia Parada Mitchell	NextEra Energy	NPCC	4

Selected Answer: Yes

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Patricia Robertson - BC Hydro and Power Authority - 1 -

Group Name: BC Hydro

Group Member Name	Entity	Region	Segments
Patricia Robertson	BC Hydro and Power Authority	WECC	1
Venkataramakrishnan Vinnakota	BC Hydro and Power Authority	WECC	2
Pat G. Harrington	BC Hydro and Power Authority	WECC	3
Clement Ma	BC Hydro and Power Authority	WECC	5

Selected Answer: Yes

Answer Comment: BC Hydro agrees with the revised Table 2 MVCD values based on a Gallet equation gap factor of 1.0. However we would point out one typo on the metric distance table for 345 kV in the 2133.6-2438.4 m elevation column. The distance stated should be 1.5 m not 0.5 m as in the table and should be corrected.

Response: **Thank you for your comment. The typographical error has been corrected in the current draft of the standard.**

Peter Heidrich - Florida Reliability Coordinating Council - 10 -

Selected Answer: Yes

Daniel Mason - City and County of San Francisco - 5 -

Selected Answer: No

Answer Comment: Hetch Hetchy Water and Power believes the changes recommended in the attached WECC FAC-003-4 position paper should be considered prior to the approval of FAC-003-4.

Response: **Please refer to the response to WECC's comments.**

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
J. Scott Williams	City Utilities of Springfield	SPP	1,4
Jim Nail	City of Independence, Power & Light Department	SPP	3,5
John Falsey	Invenergy	NA - Not Applicable	NA - Not Applicable
John Allen	City Utilities of Springfield	SPP	1,4

Kevin Giles	Westar Energy Inc..	SPP	1,3,5,6
Louis Guidry	Cleco Corporation	SPP	1,3,5,6
Michelle Corley	Cleco Corporation	SPP	1,3,5,6
Mike Kidwell	Empire District Electric	SPP	1,3,5
Robert Hirchak	Cleco Corporation	SPP	1,3,5,6

Selected Answer: Yes

Answer Comment: Our group is in support of table 2 however, we have discovered that the values are not equivalent to the metric values provided in the same table. We would requests that the drafting team review both the English and Metric values, and provide corrections as necessary.

Response: **Thank you for your comments. The team has reviewed and appropriately revised the values in the English and Metric portions of Table 2.**

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Ryan Strom	Buckeye Power, Inc.	RFC	4
Amber Skillern	East Kentucky Power Cooperative	SERC	1,3

Michael Brytowski	Great River Energy	MRO	1,3,5,6
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5
Scott Brame	North Carolina Electric Membership Corporation	SERC	3,4,5
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1

Selected Answer: Yes

Answer Comment: We agree with the values listed in Table 2, as derived from EPRI's empirical studies.

Response: **Thank you for your comment.**

Oshani Pathirane - Oshani Pathirane On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Selected Answer: Yes

2. Do you agree with modifying the elevation levels in table 2 to go up to 15,000 feet and 4,267 meters? If not, please provide your response below.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

William Hutchison - Southern Illinois Power Cooperative - 1 -

Selected Answer: Yes

John Falsey - Invenergy LLC - 5,6 - FRCC,MRO,WECC,TRE,NPCC,SERC,SPP,RFC

Selected Answer: Yes

Rob Robertson - SunEdison - 5 -

Selected Answer: Yes

Randall Hubbard - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - FRCC,WECC,TRE,SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc..	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R. Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Selected Answer: Yes

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Name: FE RBB

Group Member Name	Entity	Region	Segments

William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Selected Answer: Yes

Dan Bamber - Dan Bamber On Behalf of: David Downey, ATCO Electric, 1

Selected Answer: Yes

Herb Schrayshuen - Herb Schrayshuen - 2 -

Selected Answer: Yes

Answer Comment: Yes, but the tree line in North America may not be that high.

Response:

Thomas Foltz - AEP - 5 -

Selected Answer: Yes

Roger Dufresne - Hydro-Qu?bec Production - 5 -

Answer Comment: See comments from TransEnergie

Response: **Please see response to TransEnergie and NPCC comments.**

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Selected Answer: Yes

Answer Comment: Table 2 - Minimum Vegetation Clearance Distances (MVCD) For Alternating Current Voltage (feet) is missing the data column located between “Over 12,000 ft” and “Over 14,000 ft”. The column “Over 13, 000 ft” is not included in the table.

Response: **Thank you for your comment. The columns have been appropriately adjusted and the missing column included in the current draft of the standard.**

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: No

Answer Comment: Hydro-Quebec TransEnergie support NPCC comments

Response: **Please see response to NPCC comments.**

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5
Amy Casucelli	Xcel Energy	MRO	1,3,5,6

Selected Answer:	Yes
Michelle Amarantos - APS - Arizona Public Service Co. - 1 -	
Selected Answer:	Yes
Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC	
Selected Answer:	Yes
Laura Nelson - IDACORP - Idaho Power Company - 1 -	
Selected Answer:	Yes
Answer Comment:	Idaho Power's transmission system has no facilities at or near the stated elevation.
Response:	**Thank you for your comment.**
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP	
Selected Answer:	Yes
Tammy Porter - Tammy Porter On Behalf of: Rod Kinard, Oncor Electric Delivery, 1	
Selected Answer:	Yes

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Steven Rueckert - Western Electricity Coordinating Council - 10 -

Selected Answer: No

Answer Comment: Do not understand the need to go this high. I believe it is well above the treeline/timberline. If there is no vegetation, there is no need to manage it.

4267 meters is only 14000 feet not 15000 feet.

However, as long as the tables are consistent, we don't have any problems if they go this high.

Response: **Thank you for your comments. In regards to the values of greater than 12000 feet, the team consensus is that it is possible for facilities to be present at this altitude in North America.**

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Angela Gaines - Portland General Electric Co. - 1,3,5,6 - WECC

Selected Answer: No

Answer Comment: Please see WECC's position paper for details

Response: **Please see the response to WECC's comments above.**

Steve Wenke - Avista - Avista Corporation - 5 -

Selected Answer: Yes

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Selected Answer: Yes

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment: Texas RE inquires: was there any consideration for establishing MVCDs for lines that are below sea level (e.g., New Orleans or Death Valley)?

Please see Texas RE's observations in #1.

Response: **Thank you for your comments. The team concluded that using the values from sea level to 1000 feet (or corresponding Metric values) is appropriate for any facilities that might exist below sea level.**

Please see additional response to TRE's comments for your second comment.

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: Yes

Diana McMahon - Salt River Project - 1,3,5,6 - WECC

Selected Answer: Yes

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6

Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Selected Answer: No

Answer Comment: We support WECC Position paper, Dec 7, 2015: Table 2 – (meters) contains typographical errors; A) for Over 2133.6 m, 345kV MVCD should be 1.5, not .5m; and B) for Over 2133.6 m, 115kV MVCD should be 0.7, not .07m,

Response: **Thank you for your comment. Please see the response to WECC's comments above.**

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC

Group Name: RSC without Con Edison

Group Member Name	Entity	Region	Segments
Paul Malozewski	Hydro One.	NPCC	1
Guy Zito	Northeast Power Coordinating Council	NPCC	NA - Not Applicable
Brian Shanahan	National Grid	NPCC	1
Rob Vance	New Brunswick Power	NPCC	1
Robert J. Pellegrini	United Illuminating	NPCC	1
Sylvain Clermont	Hydro Quebec	NPCC	1
Edward Bedder	Orange and Rockland Utilities	NPCC	1
Mark J. Kenny	Eversource Energy	NPCC	1

Gregory A. Campoli	NY-ISO	NPCC	2
Si Truc Phan	Hydro Quebec	NPCC	2
Randy MacDonald	New Brunswick Power	NPCC	2
David Burke	Orange and Rockland Utilities	NPCC	3
Wayne Sipperly	New York Power Authority	NPCC	4
Connie Lowe	Dominion Resources Services	NPCC	4
David Ramkalawan	Ontario Power Generation	NPCC	4
Glen Smith	Entergy Services	NPCC	4
Brian O'Boyle	Con Edison	NPCC	5
Brian Robinson	Utility Services	NPCC	5
Bruce Metruck	New York Power Authority	NPCC	6
Alan Adamson	New York State Reliability Council	NPCC	7
Kathleen M. Goodman	ISO-New England	NPCC	2
Helen Lainis	Independent Electricity System Operator	NPCC	2
Michael Jones	National Grid	NPCC	3
Silvia Parada Mitchell	NextEra Energy	NPCC	4

Selected Answer: No

Answer Comment: In table 2 Minimum Vegetation Clearance Distances (MVCD meters) the last two column headers are mislabeled. The last two columns should be “Over 3657m up to 3962m and Over 3962m up to 4267m” per the NERC report.

In Table 2 Minimum Vegetation Clearance Distances (MVCD feet), the last two column headers are mislabeled. In the NERC report the last column is labeled 13,000 ft up to 14,000 ft.

Response: **Thank you for your comments. The team has adjusted the mislabeled column headings and added the appropriate missing values.**

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Patricia Robertson - BC Hydro and Power Authority - 1 -

Group Name: BC Hydro

Group Member Name	Entity	Region	Segments
Patricia Robertson	BC Hydro and Power Authority	WECC	1
Venkataramakrishnan Vinnakota	BC Hydro and Power Authority	WECC	2
Pat G. Harrington	BC Hydro and Power Authority	WECC	3
Clement Ma	BC Hydro and Power Authority	WECC	5

Selected Answer: Yes

Peter Heidrich - Florida Reliability Coordinating Council - 10 -

Selected Answer: Yes

Answer Comment: However, the 'feet' and 'meter' versions of Table 2 for AC are either missing a column or the last column is mislabeled.

Response: **Thank you for your comment. The team has corrected the inconsistency in the current draft of the standard.**

Daniel Mason - City and County of San Francisco - 5 -

Selected Answer: No

Answer Comment: Hetch Hetchy Water and Power believes the changes recommended in the attached WECC FAC-003-4 position paper should be considered prior to the approval of FAC-003-4.

Response: **Thank you for your comment. Please see response to WECC's comments above.**

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
J. Scott Williams	City Utilities of Springfield	SPP	1,4
Jim Nail	City of Independence, Power & Light Department	SPP	3,5
John Falsey	Invenergy	NA - Not Applicable	NA - Not Applicable
John Allen	City Utilities of Springfield	SPP	1,4
Kevin Giles	Westar Energy Inc..	SPP	1,3,5,6
Louis Guidry	Cleco Corporation	SPP	1,3,5,6
Michelle Corley	Cleco Corporation	SPP	1,3,5,6
Mike Kidwell	Empire District Electric	SPP	1,3,5

Robert Hirchak	Cleco Corporation	SPP	1,3,5,6

Selected Answer: Yes

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Ryan Strom	Buckeye Power, Inc.	RFC	4
Amber Skillern	East Kentucky Power Cooperative	SERC	1,3
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5
Scott Brame	North Carolina Electric Membership Corporation	SERC	3,4,5
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1

Selected Answer: No

Answer Comment: We recommend the SDT consider adding a graph, possibly on a logarithmic scale, to clearly list the values for each elevation. The revised table is congested with the additional information and should be modified for easier readability.

Response:	**Thank you for your comment. The team evaluated your request and determined that the current tabular format presents the information in an accurate manner.**

Oshani Pathirane - Oshani Pathirane On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Selected Answer:	No
Answer Comment:	Hydro One Networks Inc. does not agree with the elevation levels specified in Table 2. There are also a few minor modifications that need correction in Table 2.
Response:	**Thank you for your response. The team decided to remain consistent with the elevation levels used in the prior versions of FAC-003.** **The team has corrected the minor inconsistencies in the current draft of the standard.**

3. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

John Fontenot - Bryan Texas Utilities - 1 -

Answer Comment:	na

William Hutchison - Southern Illinois Power Cooperative - 1 -

Answer Comment:	None

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Answer Comment:	In the applicability section of FAC-003-4, the Standard applies in bullet 4.2.1 to "Each overhead transmission line operated at 200 kV or higher." Please comment on whether FAC-003-4 applies to non-BES lines in addition to BES lines. For example, if a 230 kV line is excluded from the BES because it is a load serving only radial line, does FAC-003-4 apply to this line as it is a transmission line operated at over 200 kV?
Response:	**Thank you for your comment. The SDT believes that Section 4.2.1 is not intended to encompass lines which, due to either (i) application of the BES Definition or (ii) due to an Approved Exception Request for an Exclusion Exception under Appendix 5C of the NERC Rules of Procedure, fall outside of the BES. Nonetheless, the SDT emphasizes that its opinion on this question is nonbinding and that this question is a compliance matter which may be addressed differently depending on facts and circumstances.**
Herb Schrayshuen - Herb Schrayshuen - 2 -	
Answer Comment:	It appears that the standard is moving back to the use of the term Planning Authority. NERC's practice in standards development has been moving toward the term Planning Coordinator as the common definition. This standard shold use Planning Coordinator in a future revision before final industry approval. ***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 Authority. <===== should be Planning Coorindator*
Response:	**Thank you for your response. The team agrees and has reverted to Planning Coordinator throughout the proposed draft standard.**
Thomas Foltz - AEP - 5 -	

Answer Comment: AEP agrees with the direction that the project team is taking, and supports their overall efforts. AEP's negative vote is driven solely by the apparent lack of equivalency between the English and Metric values that have been proposed for Table 2, and we look forward to potential corrections in the subsequent version of the draft.

Response: **Thank you for your comment. The team has revisited both the English and Metric values in Table 2 and revised the values, as appropriate, to ensure consistency.**

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Answer Comment: Dominion supports the additional comments of NPCC.

Response: **Thank you for your comments. Please see the response to the NPCC comments.**

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Answer Comment: Hydro-Quebec TransEnergie support NPCC comments

Response: **Thank you for your comments. Please see the response to the NPCC comments.**

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5
Amy Casucelli	Xcel Energy	MRO	1,3,5,6

Answer Comment: The NSRF agrees with the associated changes.

Response:	**Thank you for your comment.**

Michelle Amarantos - APS - Arizona Public Service Co. - 1 -

Selected Answer:

Answer Comment:	While the proposed FAC-003-4 provides additional clearance, APS believes that there are still gaps to address. The testing was done at the EPRI testing facility but not under all weather, topography, atmosphere conditions and variances in tree species. APS is concerned these clearance distances are still too restrictive to ensure reliability of the grid. To compound the issue, these clearances are real-time observations that don't take into account line loading (sag), temperature and time of day. APS would recommend an additional 10 feet of clearance to safeguard the reliability of the grid.
Response:	**The EPRI testing resulted in a conservative determination of the MVCD by establishing a gap factor of 1.0. The team agrees that a vegetation management program should take into account all of the factors in your comments. As stated in Footnotes 17 and 20 to Table 2 of the proposed standard, "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."**

Steven Rueckert - Western Electricity Coordinating Council - 10 -

Answer Comment:

Thank you for the opportunity to comment on the standard.

For appearance, all column widths on the tables should be the same. Values in some of the cells do not line up with the other values. This makes the table look sloppy.

I recognize that the ranges on the Metric table columns are exact translations of the 1000 foot ranges, but the numbers identifying the elevation for each column are not how entities that use the Metric System rather than the English System are going to think. No one is going to think in terms of 914.4 to 1219.2 meters. They are going to think in even numbered terms (900-1200 meters). Taking the direct translation rather than fixed, rounded terms is a slap in the face to those using the Metric System. That would be like labeling the English column 2952.7 - 3937.1 feet. The Metric column ranges should be even meters and the values in the cells adjusted accordingly.

R1 and R2 are identical in every way except the facilities that they refer to. Together they refer to all facilities. The VRFs and VSLs are also identical. I disagree with the need to separate them into two different requirements becasue the facilities in R1 are more significant. Compliance enforecement has the discretion to handle a violation differently if it is an element of an IROL or a Major WECC Path. The standard doesn't need two requirements for the same thing.

We have attached a redline version of FAC-003-4 that includes addtional suggested changes and the reasons for the suggestions.

Response:

Thank you for your comments. The column widths have been adjusted for consistency. The Metric column headings have been rounded to the nearest meter. While Requirements R1 and R2 are outside the scope of the project, your comments will be retained for the next periodic review of the FAC-003 standard.

Andrew Pusztai - American Transmission Company, LLC - 1 -

Answer Comment:

ATC has identified the following recommended improvements for consideration by the SDT to the draft Standard .

• Regarding the Applicability of Facilities Section 4.2.2., American Transmission Company (ATC) recommends revising the language for clarity, to read: "Each overhead transmission line operated below 200 kV identified as an element of *a Planning Horizon* IROL…"
• Similarly, ATC recommends revising the language of R1 to read: "Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s) which are either an element of *a Planning Horizon* IROL,…"
• ATC suggests updating the language of R2 to read: Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of *a Planning Horizon* IROL,…"
• R5 contains a grammatical error and should state: "When *an* applicable…"
• ATC recommends making updates corresponding to those above to Categories 1A, 1B, 2A, 2B, 4A, and 4B identified on pgs. 13-14: "Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of *a Planning Horizon* IROL …," "Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of *a Planning Horizon* IROL…," "Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified as an element of *a Planning Horizon* IROL…," "Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified as an element of *a Planning Horizon* IROL…," "Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified as an element of *a Planning Horizon* IROL…," and "Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified as an element of *a*

Planning Horizon IROL…"

• ATC recommends updating the proposed language in the Guidelines and Technical Basis section (pg. 24) to read: "The special case is needed because the Planning Authorities may designate lines below 200 kV to become elements of *a Planning Horizon* IROL…A line operating below 200kV designated as an element of *a Planning Horizon*..."

• The Project 2010-07.1 Adjusted MVCDs per EPRI Testing section (pg. 26) needs grammatical correction: "The advisory team *was comprised of* NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulation coordination, and vegetation management…Based on these testing results conducted by EPRI, and consistent with the report filed in FERC Docket No. RM12-4-000, the gap factor used in the Gallet equation *required* adjustment from 1.3 to 1.0…"

• The Requirements R1 and R2 section (pg. 27) should be updated to read: "R1 is applicable to lines that are identified as an element of *a Planning Horizon* IROL or Major WECC Transfer Path. R2 is applicable to all other lines that are not elements of *Planning Horizon* IROLs,... The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of *a Planning Horizon* 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 *Planning Horizon* IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of *Planning Horizon* IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant."

Response:

Thank you for your comments. While your comments refer to areas outside the scope of the project, they will be retained for the next periodic review of the FAC-003 standard. The team has addressed the grammatical issues in the current draft of the standard.

Angela Gaines - Portland General Electric Co. - 1,3,5,6 - WECC

Answer Comment: PGE is in agreement with WECC as outlined in their position paper and is casting a "No" vote for this standard. WECC's position paper is attached.

Response: **Thank you for your comment. Please see the response to WECC's comments.**

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Answer Comment: Duke Energy would like to point out to the SDT, that there appears to be an omission on Table 2 of the MVCD range of "over 13,000ft up to 14,000ft". The columns currently lists ranges from 12,000ft to 13,000ft, and then moves to 14,000ft to 15,000ft skipping over the 13,000 to 14,000ft range. Duke Energy recommends adding an additional column to include the omitted MVCD range.

Duke Energy would also like to point out that there are some inconsistencies with the number of decimal places that are used in Table 2 of the currently enforceable FAC-003-3. In some instances one decimal place is used (ex. 8.2ft) and others where two decimal places are used (ex. 8.33ft). We recommend that a consistent approach be used going forward regarding the minimum MVCD levels, and that all values use the same number of decimal places in Table 2.

Response:	**Thank you for your comments. The team has adjusted the appropriate values and added the 13000-14000 foot (and corresponding Metric) column to Table 2. The team has also reviewed and revised the English and Metric values for AC voltages in Table 2 as appropriate. The DC portion of Table 2 was not in the scope of the project.** **While some of your comments are outside the scope of the project, they will be retained for the next periodic review.**

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Answer Comment:	Texas RE noticed in R1.1, the table is referenced as FAC-003-Table 2. In the VSLs, the table is referenced as FAC-003-4-Table 2. Texas RE recommends changing the requirement language to match the VSL language to eliminate confusion and clearly indicate the table for version 4 of the standard. Texas RE noticed the VSL for R2 references FAC-003-4-Table 2 but the Requirement language itself does not. Texas RE recommends the requirement language reference Table 2 in order to be consistent with the VSL language. Should Requirement 2 language include the same phrase, “as shown in FAC-003-Table 2” with or without the “-4” reference, as Requirement 1? Texas RE inquires: does the table in the supplemental material (titled “Comparison of spark-over……”) need to be changed based on the EPRI review? Texas RE recommends reviewing the footnotes for consistency. Footnotes 9, 10, and 11 reference Footnotes 4, 5, and 6, while Footnotes 17, 19, and 21 are identical but all include the full language of the footnote. Footnotes 18 and 20 are also identical, but footnote 20 includes the full language instead of “See footnote 18”.

For example, Texas RE noticed two footnotes with similar language. On Page 8 of the Standard there is a footnote, #4, that is then referenced on Page 9 by footnote #9: "This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's or applicable Generator Owner's right to exercise its full legal rights on the ROW. "

On Page 11 in Footnote #15 there is a similar sentence to Footnote #4; "Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body."

Texas RE recommends the SDT be consistent with the language of the footnotes.

The Table 2 footnote " + Table 2- Table of MVCD…." is incorrect as the May 14, 2015. NERC Advisory did not include the 14000 to 15000 ft column.

On the Direct Current portion of Table 2, Texas RE noticed there is not a reference regarding line operated at normal voltages "other than those listed" as well. Should there be? Also, why did the SDT not extend the Direct Current portion of the Table to 15000 ft?

Texas RE recommends changing the language of R1 and R2. The Requirements should

read: “to prevent encroachments of the types shown below into the MVCD of its applicable lines, operating within their Rating and all Rated Electrical Operating Conditions, which are…..” instead of “operating within its Rating and all Rated Electrical Operating Conditions of types shown below:” The current version reads as if the “types show below” is referencing Rated Electrical Operating Conditions.

Response:

Thank you for your comments. The scope of the project did not include the Requirements and associated VRF and VSL. The use of the term “spark-over” versus “flash-over” was determined to be outside of the scope of the project.

The team agrees that the footnote “+” to Table 2 should be clarified and has made appropriate changes in the current draft of the standard.

The DC values in Table 2 are outside of the scope of this project.

While some of your comments refer to areas outside the scope of the project, they will be retained for the next periodic review of the FAC-003 standard.

Erika Doot - U.S. Bureau of Reclamation - 5 -

Answer Comment:

The Bureau of Reclamation supports the drafting team’s proposed revisions to FAC-003-4.

Response:

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Answer Comment:

As mentioned above we are supporting the WECC Position Paper of Dec 7, 2015 as follows:

• Correct the Functional Entity from "Planning Authority" to "Planning Coordinator"

• Although distances for AC lines are increased by 30% due to the study, there has been no increase in the distances for the DC lines, and no explanation is given. These distances should be considered for revision.

• For ease-of-use, the columns from "Over sea level up to 500 ft" and "Over 500 ft up to 1000 ft" should be combined to a single column "Over sea level up to 1000 ft"…only one cell will change by one tenth of a foot in only the 765kV voltage class.

• The elevation columns in the "meters" page of Table 2, are calculated to exactly match the elevations in feet, in the process the elevations given are un-workable. Elevations of 304.8m, 609.6m, 914.4m, etc. should be changed to 300m, 600m, 900 m. The MVCD's (rounded to within one tenth of a foot) will not change.

• In Table 2 for Direct Current, the MVCD's are calculated to within one hundredth of a foot – this is an un-workable level of precision.

Response: **Thank you for your comments. Please refer to the response to WECC's comments.**

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC

Group Name: RSC without Con Edison

Group Member Name	Entity	Region	Segments
Paul Malozewski	Hydro One.	NPCC	1
Guy Zito	Northeast Power Coordinating Council	NPCC	NA - Not Applicable
Brian Shanahan	National Grid	NPCC	1
Rob Vance	New Brunswick Power	NPCC	1
Robert J. Pellegrini	United Illuminating	NPCC	1
Sylvain Clermont	Hydro Quebec	NPCC	1
Edward Bedder	Orange and Rockland Utilities	NPCC	1
Mark J. Kenny	Eversource Energy	NPCC	1
Gregory A. Campoli	NY-ISO	NPCC	2
Si Truc Phan	Hydro Quebec	NPCC	2
Randy MacDonald	New Brunswick Power	NPCC	2
David Burke	Orange and Rockland Utilities	NPCC	3

Wayne Sipperly	New York Power Authority	NPCC	4
Connie Lowe	Dominion Resources Services	NPCC	4
David Ramkalawan	Ontario Power Generation	NPCC	4
Glen Smith	Entergy Services	NPCC	4
Brian O'Boyle	Con Edison	NPCC	5
Brian Robinson	Utility Services	NPCC	5
Bruce Metruck	New York Power Authority	NPCC	6
Alan Adamson	New York State Reliability Council	NPCC	7
Kathleen M. Goodman	ISO-New England	NPCC	2
Helen Lainis	Independent Electricity System Operator	NPCC	2
Michael Jones	National Grid	NPCC	3
Silvia Parada Mitchell	NextEra Energy	NPCC	4

Answer Comment: There are inconsistency with the use of terms “Planning Coordinator” and “Planning Authorities”.

NERC has been transitioning from the term planning authority to the term Planning Coordinator over the last several years.

But in this standard it has recently been change back to Planning Authority. We believe that this is the wrong designation.

Response: **Thank you for your comments. The team agrees that Planning Coordinator is the proper term and has reverted to this term throughout the proposed standard.**

Patricia Robertson - BC Hydro and Power Authority - 1 -

Group Name: BC Hydro

Group Member Name	Entity	Region	Segments
Patricia Robertson	BC Hydro and Power Authority	WECC	1
Venkataramakrishnan Vinnakota	BC Hydro and Power Authority	WECC	2
Pat G. Harrington	BC Hydro and Power Authority	WECC	3
Clement Ma	BC Hydro and Power Authority	WECC	5

Answer Comment: BC Hydro recommends changing Planning Authority to Planning Coordinator to align with current terminology.

Response: **Thank you for your comments. The team agrees that Planning Coordinator is the proper term and has reverted to this term throughout the proposed standard.**

Peter Heidrich - Florida Reliability Coordinating Council - 10 -

Answer Comment: The SDT has established inconsistency with the use of the designations "Planning Coordinator" and "Planning Authority". NERC has been transitioning from the term Planning Authority to the term Planning Coordinator, but in this standard revision the Planning Coordinator designation has been changed back to Planning Authority.

Response: **Thank you for your comments. The team agrees that Planning Coordinator is the proper term and has reverted to this term throughout the proposed standard.**

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
J. Scott Williams	City Utilities of Springfield	SPP	1,4
Jim Nail	City of Independence, Power & Light Department	SPP	3,5
John Falsey	Invenergy	NA - Not Applicable	NA - Not Applicable
John Allen	City Utilities of Springfield	SPP	1,4
Kevin Giles	Westar Energy Inc..	SPP	1,3,5,6
Louis Guidry	Cleco Corporation	SPP	1,3,5,6
Michelle Corley	Cleco Corporation	SPP	1,3,5,6
Mike Kidwell	Empire District Electric	SPP	1,3,5
Robert Hirchak	Cleco Corporation	SPP	1,3,5,6

Answer Comment:

Page 2 of the Standard….second line of the purpose definition. We would suggest to the drafting team to capitalize 'vegetation' since it is a defined term in the NERC Glossary of Terms.

Page 2 of the Standard….In section 4.1.1.1 of the Applicable Transmission Owner. We would suggest to the drafting team to not capitalize 'Transmission Facilities' since it is not a defined term in the NERC Glossary of Terms.

Page 2 of the Standard….In section 4.1.2 of the Applicable Generator Owner. We would suggest to the drafting team to not capitalize 'Facilities' since it is not a defined term in the NERC Glossary of Terms. However, the term 'Facility' is defined.

Page 2 of the Standard….In section 4.2.1, 4.2.2, 4.2.3, 4.2.4 of Facilities. We would suggest to the drafting team to capitalize 'transmission line' since it is a defined term in

the NERC Glossary of Terms.

Page 3 of the Standard….In section 4.3.1 of Generation Facilities (first line). We would suggest to the drafting team to capitalize 'transmission line' since it is a defined term in the NERC Glossary of Terms.

Page 3 of the Standard….last paragraph of the Background (first, second, and third line). We would suggest to the drafting team to capitalize 'reliability standard(s)' since it is a defined term in the NERC Glossary of Terms.

Page 4 of the Standard… bullets 2, 3, 5.). We would suggest to the drafting team to capitalize 'vegetation' since it is a defined term in the NERC Glossary of Terms. Also, we make the same suggestions in the last two paragraphs for the same term.

Page 4 of the Standard….last paragraph. We would suggest to the drafting team to capitalize 'transmission line' since it is a defined term in the NERC Glossary of Terms.

Page 5 of the Standard…..Requirement R1 (second line). We would suggest to the drafting team to capitalize 'vegetation' since it is a defined term in the NERC Glossary of Terms. Additionally, we suggest some alternative language for Requirement R1 to define or identify how these the elements of an IROL and elements of a Major WECC Transfer Path are determined. The suggested language as followed: "Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path that are determined by a particular study; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below".

Page 6 of the Standard….In sections 1.2, 1.3,1. 4 of Requirement R1. We would suggest to the drafting team to capitalize 'vegetation' since it is a defined term in the NERC

Glossary of Terms.

Page 6 of the Standard…..Measurement M1. We would suggest to the drafting team to capitalize 'vegetation' since it is a defined term in the NERC Glossary of Terms.

Page 6 of the Standard….. Requirement R2. We would suggest to the drafting team to capitalize 'vegetation' since it is a defined term in the NERC Glossary of Terms. Also, we make the same suggestions in sections 2.2, 2.3, 2.4 for the same term.

Page 7 of the Standard…..Measurement M2. We would suggest to the drafting team to capitalize 'vegetation' since it is a defined term in the NERC Glossary of Terms.

Page 7 of the Standard….. Requirement R3 (line 3). We would suggest to the drafting team to capitalize 'vegetation' since it is a defined term in the NERC Glossary of Terms.

Page 8 of the Standard….. Requirement R6 (line 2). We would suggest to the drafting team to capitalize 'transmission line' since it is a defined term in the NERC Glossary of Terms.

Page 8 of the Standard….. Measurement R6 (line 2). We would suggest to the drafting team to capitalize 'transmission line' since it is a defined term in the NERC Glossary of Terms.

Response:

Thank you for your comments. Your comments refer to areas outside the scope of the project, but will be retained for the next periodic review of the FAC-003 standard.

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Ryan Strom	Buckeye Power, Inc.	RFC	4
Amber Skillern	East Kentucky Power Cooperative	SERC	1,3
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5
Scott Brame	North Carolina Electric Membership Corporation	SERC	3,4,5
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1

Answer Comment:

(1) We question the modification from Planning Coordinator to Planning Authority. The NERC Glossary defines the PC, but not the PA. If the SDT is striving for consistency with FAC-014, we suggest developing a SAR to replace the outdated reference of the Planning Authority with the current Planning Coordinator term. It is surprising that the standards still have two terms for a single registered function. The Functional Model Working Group is conducting a review of the NERC Functional Model, and we suggest that the SDT discuss this change with them for guidance going forward.

(2) The timelines of the Implementation Plan are reasonable. However, we recommend copying the same language from the standard to the Implementation Plan for consistency.

(3) We also find Section C. Compliance, Section 1.2 Evidence Retention, second bullet, redundant, as "unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation" is already listed at the beginning of the section.

(4) We thank you for this opportunity to comment.

Response:

Thank you for your comments. The team agrees that Planning Coordinator is the proper term and has reverted to this term throughout the proposed standard.

The Implementation Plan is now a stand-alone document and not included in the proposed standard.

While some of your comments refer to areas outside the scope of the project, they will be retained for the next periodic review of the FAC-003 standard.

Oshani Pathirane - Oshani Pathirane On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Answer Comment:

While Hydro One Networks Inc. feels that the standard needs a few minor modifications and corrections, we generally support the intent of the standard. Hydro One Networks Inc. further supports the comments provided by the NPCC. Hydro One Networks Inc. agrees with the NPCC in that the "Planning Coordinator", as opposed to the "Planning Authority", should be an applicable functional entity for the standard.

Response:

Thank you for your comments. The team has reviewed the draft standard and addressed a number of minor corrections. The team agrees that Planning Coordinator is the proper term and has reverted to this term throughout the proposed standard.

End of Report

Standard Development Timeline

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

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	August 19, 2015
SAR posted for comment	August 24, 2015
45-day formal comment period with ballot	October 30, 2015

Anticipated Actions	Date
10-day final ballot	January 2016
NERC Board (Board) adoption	February 2016

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Transmission Vegetation Management

2. **Number:** FAC-003-4

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

4. **Applicability:**

4.1. Functional Entities:

4.1.1. Applicable Transmission Owners

4.1.1.1. Transmission Owners that own Transmission Facilities defined in 4.2.

4.1.2. Applicable Generator Owners

4.1.2.1. Generator Owners that own generation Facilities defined in 4.3.

4.2. Transmission Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[1], 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.

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies."*

4.3. Generation Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[2], state, provincial, public, private, or tribal entities:

4.3.1 Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) do not have a clear line of sight[3] from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and are:

4.3.1.1 Operated at 200kV or higher; or

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

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

5. Effective Date: See Implementation Plan

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

a) Performance-based defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system <u>performance result or outcome</u>?*

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 <u>reduces a stated risk</u> 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 <u>what capability</u>, 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

[2] *Id.*

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

should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.

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

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

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

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

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

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

includes municipal lands, village lands, city lands, and a host of other governmental entities.

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

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

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

B. Requirements and Measures

R1. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below[4] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:

[4] This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote

1.1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,[5]

1.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[6]

1.3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[7],

1.4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.[8]

M1. Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

R2. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[9] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:

2.1 An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage,[10]

2.2 An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[11]

2.3 An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,[12]

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should be construed to limit the Transmission Owner's or applicable Generator Owner's right to exercise its full legal rights on the ROW.

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

[6] 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.

[7] *Id.*

[8] *Id.*

[9] See footnote 4.

[10] See footnote 5.

[11] See footnote 6.

[12] *Id.*

2.4 An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage.[13]

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

R3. Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]:*

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.

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

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

M4. Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

R5. When an applicable Transmission Owner and an applicable Generator Owner are 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

[13] *Id.*

a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M5. Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

R6. Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW[14] [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M6. Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

R7. Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.). Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

7.1 Change in expected growth rate/environmental factors

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

7.2 Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner[15]

7.3 Rescheduling work between growing seasons

7.4 Crew or contractor availability/Mutual assistance agreements

7.5 Identified unanticipated high priority work

7.6 Weather conditions/Accessibility

7.7 Permitting delays

7.8 Land ownership changes/Change in land use by the landowner

7.9 Emerging technologies

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

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

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

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

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

- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, for three calendar years.
- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- If an applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information

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

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

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

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;

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

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

Violation Severity Levels (Table 1)

R #	Table 1: Violation Severity Levels (VSL)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following: • *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.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not

			identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	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: • *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*
R3.		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity's applicable lines. (Requirement R3, Part 3.2)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines. (Requirement R3, Part 3.1)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity's applicable lines.

R4.			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5.				The responsible entity did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6.	The responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7.	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

		plan for its applicable lines (as finally modified).	plan for its applicable lines (as finally modified).	

D. Regional Variances

None.

E. Associated Documents

- FAC-003-4 Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	January 20, 2006	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.	New
1	April 4, 2007	Regulatory Approval - Effective Date	New
2	November 3, 2011	Adopted by the NERC Board of Trustees	New
2	March 21, 2013	FERC Order issued approving FAC-003-2 (Order No. 777) FERC Order No. 777 was issued on March 21, 2013 directing NERC to "conduct or contract testing to	Revisions

		obtain empirical data and submit a report to the Commission providing the results of the testing."[16]	
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."	Revisions
3	May 9, 2013	FAC-003-3 adopted by Board of Trustees	Revisions
3	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-003-3. This standard became enforceable on July 1, 2014 for Transmission Owners. For Generator Owners, R3 became enforceable on January 1, 2015 and all other requirements (R1, R2, R4, R5, R6, and R7) became enforceable on January 1, 2016.	Revisions
3	November 22, 2013	Updated the VRF for R2 from "Medium" to "High" per a Final Rule issued by FERC	Revisions
3	July 30, 2014	Transferred the effective dates section from FAC-003-2 (for Transmission Owners) into FAC-003-3, per the FAC-003-3 implementation plan	Revisions
4	Projected final posting January 22, 2016	Adjusted MVCD values in Table 2 for alternating current systems, consistent with findings reported in report filed on August 12, 2015 in Docket No. RM12-4-002 consistent with FERC's directive in Order No. 777, and based on empirical testing results for flashover distances between conductors and vegetation.	Revisions

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

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[17]

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)[+]	(AC) Maximum System Voltage (kV)[18]	MVCD (feet) Over sea level up to 500 ft	MVCD feet Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft	MVCD feet Over 11000 ft up to 12000 ft	MVCD feet Over 12000 ft up to 13000 ft	MVCD feet Over 13000 ft up to 14000 ft	MVCD feet Over 14000 ft up to 15000 ft
765	800	11.6ft	11.7ft	11.9ft	12.1ft	12.2ft	12.4ft	12.6ft	12.8ft	13.0ft	13.1ft	13.3ft	13.5ft	13.7ft	13.9ft	14.1ft	14.3ft
500	550	7.0ft	7.1ft	7.2ft	7.4ft	7.5ft	7.6ft	7.8ft	7.9ft	8.1ft	8.2ft	8.3ft	8.5ft	8.6ft	8.8ft	8.9ft	9.1ft
345	362[19]	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft
287	302	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft	5.8ft	5.9ft	6.1ft	6.2ft	6.3ft	6.4ft	6.5ft	6.6ft	6.8ft	6.9ft
230	242	4.0ft	4.1ft	4.2ft	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft
161*	169	2.7ft	2.7ft	2.8ft	2.9ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft	3.3ft	3.3ft	3.4ft	3.5ft	3.6ft	3.7ft	3.8ft
138*	145	2.3ft	2.3ft	2.4ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft	2.7ft	2.8ft	2.8ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft
115*	121	1.9ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.1ft	2.2ft	2.2ft	2.3ft	2.3ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft
88*	100	1.5ft	1.5ft	1.6ft	1.6ft	1.7ft	1.7ft	1.8ft	1.8ft	1.8ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.2ft	2.2ft
69*	72	1.1ft	1.1ft	1.1ft	1.2ft	1.2ft	1.2ft	1.2ft	1.3ft	1.3ft	1.3ft	1.4ft	1.4ft	1.4ft	1.5ft	1.6ft	1.6ft

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

[+] *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)*

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[17] 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.

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

[19] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the Supplemental Materials for additional information.

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[20]

For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)[+]	(AC) Maximum System Voltage (kV)[21]	MVCD meters Over sea level up to 153 m	MVCD meters Over 153m up to 305m	MVCD meters Over 305m up to 610m	MVCD meters Over 610m up to 915m	MVCD meters Over 915m up to 1220m	MVCD meters Over 1220m up to 1524m	MVCD meters Over 1524m up to 1829m	MVCD meters Over 1829m up to 2134m	MVCD meters Over 2134m up to 2439m	MVCD meters Over 2439m up to 2744m	MVCD meters Over 2744m up to 3048m	MVCD meters Over 3048m up to 3353m	MVCD meters Over 3353m up to 3657m	MVCD meters Over 3657m up to 3962m	MVCD meters Over 3962 m up to 4268 m	MVCD meters Over 4268m up to 4572m
765	800	3.6m	3.6m	3.6m	3.7m	3.7m	3.8m	3.8m	3.9m	4.0m	4.0m	4.1m	4.1m	4.2m	4.2m	4.3m	4.4m
500	550	2.1m	2.2m	2.2m	2.3m	2.3m	2.3m	2.4m	2.4m	2.5m	2..5m	2.5m	2.6m	2.6m	2.7m	2.7m	2.7m
345	362[22]	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m	1.7m	1.7m	1.8m
287	302	1.6m	1.6m	1.7m	1.7m	1.7m	1.7m	1.8m	1.8m	1.9m	1.9m	1.9m	2.0m	2.0m	2.0m	2.1m	2.1m
230	242	1.2m	1.3m	1.3m	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m
161*	169	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m	1.0m	1.0m	1.0m	1.1m	1.1m	1.1m	1.1m
138*	145	0.7m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m
115*	121	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	.07m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.8m
88*	100	0.4m	0.4m	0.5m	0.5m	0.5m	0.5m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m
69*	72	0.3m	0.3m	0.3m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.5m	0.5m	0.5m

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

[+] *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)*

[20] 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.

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

[22] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the supplemental materials for additional information.

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[23]

For **Direct Current** Voltages feet (meters)

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

[23] 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.

Guideline and Technical Basis

Effective dates:

The Compliance section is standard language used in most NERC standards to cover the general effective date and covers the vast majority of situations. A special case covers effective dates for (1) lines initially becoming subject to the Standard, (2) lines changing in applicability within the standard.

The special case 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 2015 may identify a line to have that designation beginning in PY 2025, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. 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.

Date that Planning Study is completed	PY the line will become an IROL element	Date 1	Date 2	Effective Date The later of Date 1 or Date 2
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

Defined Terms:

Explanation for revising the definition of ROW:
The current NERC glossary definition of Right of Way has been modified to include Generator Owners and to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This 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 current 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 Inspection:
The current glossary definition of this NERC term was modified to include Generator Owners and to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

Explanation of the derivation of the MVCD:
The MVCD is a calculated minimum distance that is derived from the Gallet equation. 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 of the Standard provides MVCD values for various voltages and altitudes. The table is based on empirical testing data from EPRI as requested by FERC in Order No. 777.

Project 2010-07.1 Adjusted MVCDs per EPRI Testing:
In Order No. 777, FERC directed NERC to undertake testing to gather empirical data validating the appropriate gap factor used in the Gallet equation to calculate MVCDs, specifically the gap factor for the flash-over distances between conductors and vegetation. See, Order No. 777, at P 60. NERC engaged industry through a collaborative research project and contracted EPRI to complete the scope of work. In January 2014, NERC formed an advisory group to assist with developing the scope of work for the project. This team provided subject matter expertise for developing the test plan, monitoring testing, and vetting the analysis and conclusions to be submitted in a final report. The advisory team was comprised of NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulation coordination, and vegetation management. The testing project commenced in April 2014 and continued through October 2014 with the final set of testing completed in May 2015. Based on these testing results conducted by EPRI, and consistent with the report filed in FERC Docket No. RM12-4-000, the gap factor used in the Gallet equation required adjustment from 1.3 to 1.0. This resulted in increased MVCD values for all alternating current system voltages identified. The adjusted MVCD values, reflecting the 1.0 gap factor, are included in Table 2 of version 4 of FAC-003.

The air gap testing completed by EPRI per FERC Order No. 777 established that trees with large spreading canopies growing directly below energized high voltage conductors create the

greatest likelihood of an air gap flash over incident and was a key driver in changing the gap factor to a more conservative value of 1.0 in version 4 of this standard.

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

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant.

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

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

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's

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

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

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

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

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

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

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated*

2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

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

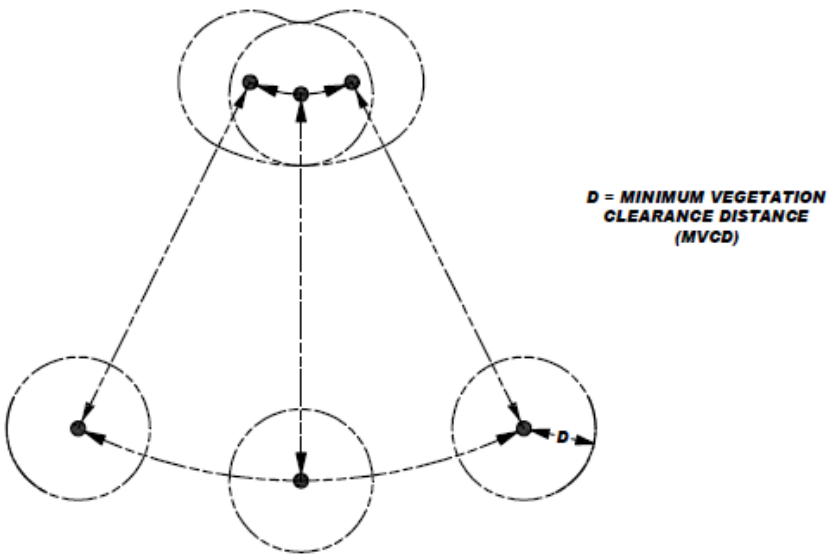

Figure 1

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

Requirement R4:

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

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

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

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

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

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

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

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of herbicides to control incompatible vegetation outside of the MVCD, but agree to the use of mechanical clearing. In

this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

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

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

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

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

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable

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

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

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

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

other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

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

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

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 used 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-003-1 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 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 was approximately 2.0 per unit. This value was 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 was 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 was 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.

Since no empirical data for spark over distances to live vegetation existed at the time version 3 was developed, the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

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

Comparison of spark-over distances computed using Gallet wet equations vs.

IEEE 516-2003 MAID distances

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

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

Rationale for Applicability (section 4.2.4):
The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows:

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

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

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

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

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

Rationale for R3:
The documentation provides a basis for evaluating the competency of the applicable Transmission Owner’s or applicable Generator Owner’s vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the

applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions.

Rationale for R4:

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

Rationale for R5:

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

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

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

Rationale for R6:

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

Rationale for R7:

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

Standard Development Timeline

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

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	August 19, 2015
SAR posted for comment	August 24, 2015
45-day formal comment period with ballot	October 30, 2015

Anticipated Actions	Date
~~45-day formal comment period with ballot~~	~~October 2015~~
10-day final ballot	January 2016
NERC Board (Board) adoption	February 2016

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Transmission Vegetation Management

2. **Number:** FAC-003-4

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

4. **Applicability:**

4.1. Functional Entities:

4.1.1. Applicable Transmission Owners

4.1.1.1. Transmission Owners that own Transmission Facilities defined in 4.2.

4.1.2. Applicable Generator Owners

4.1.2.1. Generator Owners that own generation Facilities defined in 4.3.

4.2. Transmission Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[1], 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 ~~Authority~~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.

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies."*

4.3. Generation Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[2], state, provincial, public, private, or tribal entities:

4.3.1 Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) do not have a clear line of sight[3] from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and are:

4.3.1.1 Operated at 200kV or higher; or

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

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

5. Effective Date: See Implementation Plan

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

a) Performance-based defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome?*

b) Risk-based preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?*

c) Competency-based defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?*

The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system

[2] *Id.*

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

failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.

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

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

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

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

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

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

includes municipal lands, village lands, city lands, and a host of other governmental entities.

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

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

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

B. Requirements and Measures

R1. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below[4] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:

[4] This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote

1.1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,[5]

1.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[6]

1.3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[7],

1.4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.[8]

M1. Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

R2. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[9] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:

2.1 An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage,[10]

2.2 An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[11]

2.3 An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,[12]

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should be construed to limit the Transmission Owner's or applicable Generator Owner's right to exercise its full legal rights on the ROW.

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

[6] 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.

[7] *Id.*

[8] *Id.*

[9] See footnote 4.

[10] See footnote 5.

[11] See footnote 6.

[12] *Id.*

2.4 An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage.[13]

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

R3. Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]:*

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.

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

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

M4. Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

R5. When an applicable Transmission Owner and an applicable Generator Owner are~~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

[13] *Id.*

a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M5. Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

R6. Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW[14] [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M6. Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

R7. Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.). Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

7.1 Change in expected growth rate/environmental factors

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

7.2 Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner[15]

7.3 Rescheduling work between growing seasons

7.4 Crew or contractor availability/Mutual assistance agreements

7.5 Identified unanticipated high priority work

7.6 Weather conditions/Accessibility

7.7 Permitting delays

7.8 Land ownership changes/Change in land use by the landowner

7.9 Emerging technologies

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

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

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

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

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

- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, for three calendar years.
- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- If an applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information

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

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

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

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;

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

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

Violation Severity Levels (Table 1)

R #	Table 1: Violation Severity Levels (VSL)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following: • *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.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not

			identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	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: • *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*
R3.		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity's applicable lines. (Requirement R3, Part 3.2)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines. (Requirement R3, Part 3.1)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity's applicable lines.

R4.			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5.				The responsible entity did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6.	The responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7.	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

		plan for its applicable lines (as finally modified).	plan for its applicable lines (as finally modified).	

D. Regional Variances

None.

E. Associated Documents

- ~~Link to FAC-003-4 Implementation Plan~~
- FAC-003-4 Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	January 20, 2006	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.	New
1	April 4, 2007	Regulatory Approval - Effective Date	New
2	November 3, 2011	Adopted by the NERC Board of Trustees	New
2	March 21, 2013	FERC Order issued approving FAC-003-2 (Order No. 777) FERC Order No. 777 was issued on March 21, 2013 directing NERC to "conduct or contract testing to	Revisions

		obtain empirical data and submit a report to the Commission providing the results of the testing."[16]	
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."	Revisions
3	May 9, 2013	FAC-003-3 adopted by Board of Trustees	Revisions
3	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-003-3. This standard ~~becomes~~became enforceable on July 1, 2014 for Transmission Owners. For Generator Owners, R3 ~~becomes~~became enforceable on January 1, 2015 and all other requirements (R1, R2, R4, R5, R6, and R7) ~~will become~~became enforceable on January 1, 2016.	Revisions
3	November 22, 2013	Updated the VRF for R2 from "Medium" to "High" per a Final Rule issued by FERC	Revisions
3	July 30, 2014	Transferred the effective dates section from FAC-003-2 (for Transmission Owners) into FAC-003-3, per the FAC-003-3 implementation plan	Revisions
4	Projected ~~initial~~final posting ~~October 2015~~January 22, 2016	Adjusted MVCD values in Table 2 for alternating current systems, consistent with findings reported in report filed on August 12, 2015 in Docket No. RM12-4-002 consistent with FERC's directive in Order No. 777, and based on empirical testing results for	Revisions

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

		flashover distances between conductors and vegetation.	

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[17]

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)[+]	(AC) Maximum System Voltage (kV)[18]	MVCD (feet) Over sea level up to 500 ft	MVCD feet Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft	MVCD feet Over 11000 ft up to 12000 ft	MVCD feet Over 12000 ft up to 13000 ft	MVCD feet Over 13000 ft up to 14000 ft	MVCD feet Over 14000 ft up to 15000 ft
765	800	11.6ft	11.7ft	11.9ft	12.1ft	12.2ft	12.4ft	12.6ft	12.8ft	13.0ft	13.1ft	13.3ft	13.5ft	13.7ft	13.9ft	14.~~0ft~~1ft	14.3ft
500	550	7.0ft	7.1ft	7.2ft	7.4ft	7.5ft	7.6ft	7.8ft	7.9ft	8.1ft	8.2ft	8.3ft	8.5ft	8.6ft	8.8ft	8.9ft	9.1ft
345	362[19]	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft
287	302	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft	5.8ft	5.9ft	6.1ft	6.2ft	6.3ft	6.4ft	6.5ft	6.6ft	6.~~7ft~~8ft	6.9ft
230	242	4.0ft	4.1ft	4.~~2t~~2ft	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft
161*	169	2.7ft	2.7ft	2.8ft	2.9ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft	3.3ft	3.3ft	3.4ft	3.5ft	3.6ft	3.~~6ft~~7ft	3.8ft
138*	145	2.3ft	2.3ft	2.4ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft	2.7ft	2.8ft	2.8ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft
115*	121	1.9ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.1ft	2.2ft	2.2ft	2.3ft	2.3ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft
88*	100	1.5ft	1.5ft	1.6ft	1.6ft	1.7ft	1.7ft	1.8ft	1.8ft	1.8ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.~~1ft~~2ft	2.2ft
69*	72	1.1ft	1.1ft	1.1ft	1.2ft	1.2ft	1.2ft	1.2ft	1.3ft	1.3ft	1.3ft	1.4ft	1.4ft	1.4ft	1.5ft	1.~~5ft~~6ft	1.6ft

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

[+] *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the ~~NERC Advisory posted on May 14, 2015.~~ EPRI report filed with FERC on August 12, 2015~~.~~. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)*

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[17] 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.

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

[19] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the Supplemental Materials for additional information.

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[20]

For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)+	(AC) Maximum System Voltage (kV)[21]	MVCD meters Over sea level up to ~~152.4~~153 m	MVCD meters Over ~~152.4 m~~153m up to ~~304.8 m~~305m	MVCD meters Over ~~304.8 m~~305m up to ~~609.6m~~610m	MVCD meters Over ~~609.6m~~610m up to ~~914.4m~~915m	MVCD meters Over ~~914.4m~~915m up to ~~1219.2m~~1220m	MVCD meters Over ~~1219.2m~~1220m up to 1524m	MVCD meters Over ~~1524 m~~1524m up to ~~1828.8 m~~1829m	MVCD meters Over ~~1828.8m~~1829m up to ~~2133.6m~~2134m	MVCD meters Over ~~2133.6m~~2134m up to ~~2438.4m~~2439m	MVCD meters Over ~~2438.4m~~2439m up to ~~2743.2m~~2744m	MVCD meters Over ~~2743.2m~~2744m up to 3048m	MVCD meters Over 3048m up to ~~3352.8m~~3353m	MVCD meters Over 3353m up to 3657m	MVCD meters Over 3657m up to 3962m	MVCD meters Over ~~3692m~~3962 m up to ~~4267m~~4268 m	MVCD meters Over 4268m up to 4572m
765	800	3.6m	3.6m	3.6m	3.7m	3.7m	3.8m	3.8m	3.9m	4.0m	4.0m	4.1m	4.1m	4.2m	4.2m	4.3m	4.4m
500	550	2.1m	2.2m	2.2m	2.3m	2.3m	2.3m	2.4m	2.4m	2.5m	2..5m	2.5m	2.6m	2.6m	2.7m	2.7m	2.7m
345	362[22]	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m	1.7m	1.7m	1.8m
287	302	1.6m	1.6m	1.7m	1.7m	1.7m	1.7m	1.8m	1.8m	1.9m	1.9m	1.9m	2.0m	2.0m	2.0m	2.1m	2.1m
230	242	1.2m	1.3m	1.3m	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m
161*	169	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m	1.0m	1.0m	1.0m	1.1m	1.1m	1.1m	1.1m
138*	145	0.7m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	~~0.9m~~1.0 m	1.0m
115*	121	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	.07m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.8m
88*	100	0.4m	0.4m	0.5m	0.5m	0.5m	0.5m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.~~6m~~7m	0.7m
69*	72	0.3m	0.3m	0.3m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.5m	0.5m	0.5m

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

+ Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the ~~NERC Advisory posted on May 14, 2015.~~ EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)

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[20] 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.

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

[22] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the supplemental materials for additional information.

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[23]

For **Direct Current** Voltages feet (meters)

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

[23] 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.

Guideline and Technical Basis

Effective dates:

The Compliance section is standard language used in most NERC standards to cover the general effective date and covers the vast majority of situations. A special case covers effective dates for (1)- lines initially becoming subject to the Standard, (2) lines changing in applicability within the standard.

The special case is needed because the Planning ~~Authorities~~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 ~~Authority~~Coordinator in 2015 may identify a line to have that designation beginning in PY 2025, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. 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.

Date that Planning Study is completed	PY the line will become an IROL element	Date 1	Date 2	Effective Date The ~~latter~~later of Date 1 or Date 2
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

Defined Terms:

Explanation for revising the definition of ROW:
The current NERC glossary definition of Right of Way has been modified to include Generator Owners and to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This 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 current 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~~Inspection:
The current glossary definition of this NERC term ~~is being~~was modified to include Generator Owners and to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

Explanation of the derivation of the MVCD:
The MVCD is a calculated minimum distance that is derived from the Gallet ~~Equations~~equation. 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~~of the Standard provides MVCD values for various voltages and altitudes. The table is based on empirical testing data from EPRI as requested by FERC in Order No. 777.

Project 2010-07.1 Adjusted MVCDs per EPRI Testing:
In Order No. 777, FERC directed NERC to undertake testing to gather empirical data validating the appropriate gap factor used in the Gallet equation to calculate MVCDs, specifically the gap factor for the flash-over distances between conductors and vegetation. See, Order No. 777, at P 60. NERC engaged industry through a collaborative research project and contracted EPRI to complete the scope of work. In January 2014, NERC formed an advisory group to assist with developing the scope of work for the project. This team provided subject matter expertise for developing the test plan, monitoring testing, and vetting the analysis and conclusions to be submitted in a final report. The advisory team was comprised of NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulation coordination, and vegetation management. The testing project commenced in April 2014 and continued through October 2014 with the final set of testing completed in May 2015. Based on these testing results conducted by EPRI, and consistent with the report filed in FERC Docket No. RM12-4-000, the gap factor used in the Gallet equation ~~require~~required adjustment from 1.3 to 1.0. This resulted in increased MVCD values for all alternating current system voltages identified. The adjusted MVCD values, reflecting the 1.0 gap factor, are included in Table 2 of version 4 of FAC-003.

The air gap testing completed by EPRI per FERC Order No. 777 established that trees with large spreading canopies growing directly below energized high voltage conductors create the

greatest likelihood of an air gap flash over incident and was a key driver in changing the gap factor to a more conservative value of 1.0 in version 4 of this standard.

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

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant.

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

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

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's

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

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

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

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

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

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

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated*

2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

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

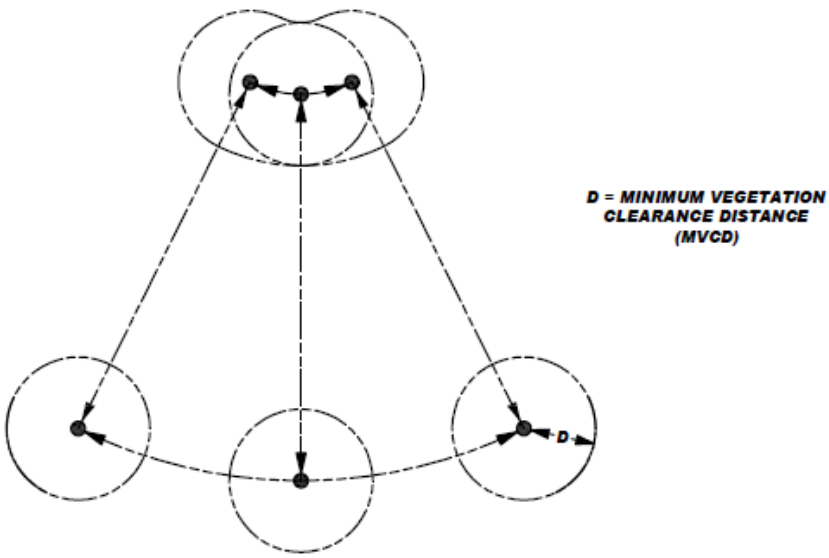

Figure 1

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

Requirement R4:

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

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

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

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

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

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

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

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of ~~chemicals on non-threatening, low growth~~herbicides to control incompatible vegetation outside of the MVCD, but

agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

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

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

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

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

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

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

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

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

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

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

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

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~~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~~used 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~~1 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~~was approximately 2.0 per unit. This value ~~is~~was 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~~was 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~~was considered a realistic maximum.

The Gallet ~~Equations~~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~~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.

Since no empirical data for spark over distances to live vegetation existed at the time version 3 was developed, the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

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

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

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

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

Rationale for Applicability (section 4.2.4):
The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows:

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

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

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

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

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

Rationale for R3:
The documentation provides a basis for evaluating the competency of the applicable Transmission Owner's or applicable Generator Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the

applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions.

Rationale for R4:

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

Rationale for R5:

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

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

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

Rationale for R6:

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

Rationale for R7:

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

~~Effective Dates~~

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

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

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

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

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

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

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~~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.~~

~~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.~~

~~2. 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.~~

~~2. 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.~~

~~2. 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.~~

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Standard Development Timeline

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

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	August 19, 2015
SAR posted for comment	August 24, 2015
45-day formal comment period with ballot	October 30, 2015

Anticipated Actions	Date
10-day final ballot	January 2016
NERC Board (Board) adoption	February 2016

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When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Transmission Vegetation Management

2. **Number:** FAC-003-~~3~~4

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:**

~~4.3.~~4.1. **Functional Entities:**

~~4.3.1.~~4.1.1. Applicable Transmission Owners

4.1.1.1. ~~4.1.1.1~~ Transmission Owners that own Transmission Facilities defined in 4.2.

4.1.2. ~~4.1.2~~ Applicable Generator Owners

4.1.2.1. ~~4.1.2.1~~ Generator Owners that own generation Facilities defined in 4.3.

~~4.4.~~4.2. **Transmission Facilities:** Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities:

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

4.2.2. ~~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. ~~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. ~~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

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies."*

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substation and any portion of the span of the transmission line that is crossing the substation fence.

~~4.5.~~4.3. **Generation Facilities:** Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[2], state, provincial, public, private, or tribal entities:

4.3.1 ~~4.3.1~~ Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) do not have a clear line of sight[3] from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and are:

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

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

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

~~Enforcement:~~

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

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

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

[2] *Id.*

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

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

~~5. Background:~~

5. Effective Date: See Implementation Plan

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

a) ~~a)~~ Performance-based— defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome?*

b) ~~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) ~~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:

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- 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.

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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.

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B. Requirements and Measures

R1. ~~R1.~~ Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the ~~MVCD~~Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below[4] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:

~~1.~~**1.1.** An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,[5]

~~2.~~**1.2.** An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[6]

~~3.~~**1.3.** An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[7],

~~4.~~**1.4.** An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.[8]

M1. ~~M1.~~ Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

R2. ~~R2.~~ Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer

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

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

[6] 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.

[7] *Id.*

[8] *Id.*

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Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[9] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:

~~1.~~2.1 An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage,[10]

~~2.~~2.2 An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[11]

~~3.~~2.3 An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,[12]

~~4.~~2.4 An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage.[13]

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

R3. ~~R3.~~ Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]:*

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

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

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

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

[9] See footnote 4.
[10] See footnote 5.
[11] See footnote 6.
[12] *Id.*
[13] *Id.*

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

M4. ~~**M4.**~~ Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

R5. ~~**R5.**~~ When ~~a~~an applicable Transmission Owner and an applicable Generator Owner ~~is~~are constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M5. ~~**M5.**~~ Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

R6. ~~**R6.**~~ Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW[14] [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

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

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M6. ~~M6.~~ Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

R7. ~~R7.~~ Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc~~.)~~.). Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

- **7.1** Change in expected growth rate/~~-~~environmental factors
- **7.2** Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner[15]
- **7.3** Rescheduling work between growing seasons
- **7.4** Crew or contractor availability/~~-~~Mutual assistance agreements
- **7.5** Identified unanticipated high priority work
- **7.6** Weather conditions/Accessibility
- **7.7** Permitting delays
- **7.8** Land ownership changes/Change in land use by the landowner
- **7.9** Emerging technologies

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

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

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C. Compliance

1. Compliance Monitoring Process

~~1.1~~1.1. Compliance Enforcement Authority:

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

~~For NERC, a third-party monitor without vested interest in the outcome for NERC shall serve as the Compliance Enforcement~~an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

~~1.2~~1.2. Evidence Retention:

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

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

- The applicable Transmission Owner and applicable Generator Owner 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~~for three calendar years.
- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- If ~~a~~an applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

1.3. ~~The~~ Compliance Monitoring and Enforcement ~~Authority shall keep~~Program

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As defined in the ~~last audit records and all requested and submitted subsequent audit records.~~

~~1.3~~ NERC Rules of Procedure, "Compliance Monitoring and Enforcement ~~Processes:~~Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

~~Compliance Audit~~

~~Self-Certification~~

~~Spot Checking~~

~~Compliance Violation Investigation~~

~~Self-Reporting~~

~~Complaint~~

~~Periodic Data Submittal~~

~~1.4~~1.4. Additional Compliance Information

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

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

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

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

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

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

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Violation Severity Levels (Table ~~of Compliance Elements~~1)

R #	~~Time Horizon~~	~~VRF~~	~~Table 1:~~ Violation Severity ~~Level~~Levels (VSL)				
			Lower VSL	Moderate VSL		High VSL	Severe VSL
R1.			~~Real time~~	~~High~~		The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained

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						Outage was caused by one of the following: • *A fall-in from inside the active transmission line ROW* • *Blowing together of applicable lines and vegetation located inside the active*

						trans missio n line ROW • *A grow-in*
R2.	~~Real-time~~	~~High~~			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained

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						Outage was caused by one of the following: • *A fall-in from inside the active transmission line ROW* • *Blowing together of applicable lines and vegetation located inside the active*

							trans missio n line ROW • *A grow-in*
R3.	~~Long-Term Planning~~	~~Lo we r~~		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity's applicable lines. (Requirement R3, Part 3.2)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines. (Requirement R3, Part 3.1)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the

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							MVCD, for the responsible entity's applicable lines.
R4.	~~Real-time~~			~~Medium~~		The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5.	~~Operations Planning~~			~~Medium~~			The responsible entity did not take

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							corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6.	~~Operations Planning~~	~~Medium~~	The responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).		The responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line,

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

D. Regional ~~Differences~~Variances

None.

~~E. Interpretations~~

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~~None.~~

~~F.~~E. Associated Documents

- FAC-003-4 Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	January 20, 2006	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.	New
1	April 4, 2007	Regulatory Approval - Effective Date	New
2	November 3, 2011	Adopted by the NERC Board of Trustees	New
2	March 21, 2013	FERC Order issued approving FAC-003-2 (Order No. 777) FERC Order No. 777 was issued on March 21, 2013 directing NERC to "conduct or contract testing to obtain empirical data and submit a report to the Commission providing the results of the testing."[16]	Revisions

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

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."	Revisions
3	May 9, 2013	FAC-003-3 adopted by Board of Trustees	Revisions
3	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-003-3. This standard became enforceable on July 1, 2014 for Transmission Owners. For Generator Owners, R3 became enforceable on January 1, 2015 and all other requirements (R1, R2, R4, R5, R6, and R7) became enforceable on January 1, 2016.	Revisions
3	November 22, 2013	Updated the VRF for R2 from "Medium" to "High" per a Final Rule issued by FERC	Revisions
3	July 30, 2014	Transferred the effective dates section from FAC-003-2 (for Transmission Owners) into FAC-003-3, per the FAC-003-3 implementation plan	Revisions
4	Projected final posting January 22, 2016	Adjusted MVCD values in Table 2 for alternating current systems, consistent with findings reported in report filed on August 12, 2015 in Docket No. RM12-4-002 consistent with FERC's directive in Order No. 777, and based on empirical testing results for flashover distances between conductors and vegetation.	Revisions

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[17]

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)+	(AC) Maximum System Voltage (kV)[18]	MVCD (feet) Over sea level up to 500 ft	MVCD feet Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft	MVCD feet Over 11000 ft up to 12000 ft	MVCD feet Over 12000 ft up to 13000 ft	MVCD feet Over 13000 ft up to 14000 ft	MVCD feet Over 14000 ft up to 15000 ft
765	800	11.6ft	11.7ft	11.9ft	12.1ft	12.2ft	12.4ft	12.6ft	12.8ft	13.0ft	13.1ft	13.3ft	13.5ft	13.7ft	13.9ft	14.1ft	14.3ft
500	550	7.0ft	7.1ft	7.2ft	7.4ft	7.5ft	7.6ft	7.8ft	7.9ft	8.1ft	8.2ft	8.3ft	8.5ft	8.6ft	8.8ft	8.9ft	9.1ft
345	362[19]	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft
287	302	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft	5.8ft	5.9ft	6.1ft	6.2ft	6.3ft	6.4ft	6.5ft	6.6ft	6.8ft	6.9ft
230	242	4.0ft	4.1ft	4.2ft	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft
161*	169	2.7ft	2.7ft	2.8ft	2.9ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft	3.3ft	3.3ft	3.4ft	3.5ft	3.6ft	3.7ft	3.8ft
138*	145	2.3ft	2.3ft	2.4ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft	2.7ft	2.8ft	2.8ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft
115*	121	1.9ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.1ft	2.2ft	2.2ft	2.3ft	2.3ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft
88*	100	1.5ft	1.5ft	1.6ft	1.6ft	1.7ft	1.7ft	1.8ft	1.8ft	1.8ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.2ft	2.2ft
69*	72	1.1ft	1.1ft	1.1ft	1.2ft	1.2ft	1.2ft	1.2ft	1.3ft	1.3ft	1.3ft	1.4ft	1.4ft	1.4ft	1.5ft	1.6ft	1.6ft

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

+ Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)

[17] 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.

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

[19] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the Supplemental Materials for additional information.

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TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[20]

For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)+	(AC) Maximum System Voltage (kV)[21]	MVCD meters Over sea level up to 153 m	MVCD meters Over 153m up to 305m	MVCD meters Over 305m up to 610m	MVCD meters Over 610m up to 915m	MVCD meters Over 915m up to 1220m	MVCD meters Over 1220m up to 1524m	MVCD meters Over 1524m up to 1829m	MVCD meters Over 1829m up to 2134m	MVCD meters Over 2134m up to 2439m	MVCD meters Over 2439m up to 2744m	MVCD meters Over 2744m up to 3048m	MVCD meters Over 3048m up to 3353m	MVCD meters Over 3353m up to 3657m	MVCD meters Over 3657m up to 3962m	MVCD meters Over 3962 m up to 4268 m	MVCD meters Over 4268m up to 4572m
765	800	3.6m	3.6m	3.6m	3.7m	3.7m	3.8m	3.8m	3.9m	4.0m	4.0m	4.1m	4.1m	4.2m	4.2m	4.3m	4.4m
500	550	2.1m	2.2m	2.2m	2.3m	2.3m	2.3m	2.4m	2.4m	2.5m	2..5m	2.5m	2.6m	2.6m	2.7m	2.7m	2.7m
345	362[22]	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m	1.7m	1.7m	1.8m
287	302	1.6m	1.6m	1.7m	1.7m	1.7m	1.7m	1.8m	1.8m	1.9m	1.9m	1.9m	2.0m	2.0m	2.0m	2.1m	2.1m
230	242	1.2m	1.3m	1.3m	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m
161*	169	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m	1.0m	1.0m	1.0m	1.1m	1.1m	1.1m	1.1m
138*	145	0.7m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m
115*	121	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	.07m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.8m
88*	100	0.4m	0.4m	0.5m	0.5m	0.5m	0.5m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m
69*	72	0.3m	0.3m	0.3m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.5m	0.5m	0.5m

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

+ Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)

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[20] 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.

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

[22] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the supplemental materials for additional information.

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[23]

For **Direct Current** Voltages feet (meters)

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

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[23] 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.

Guideline and Technical Basis ~~(attached).~~

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~~Guideline and Technical Basis~~

Effective dates:

~~The first two sentences of the Effective Dates~~The Compliance section is standard language used in most NERC standards to cover the general effective date and ~~is sufficient to cover~~covers the vast majority of situations. ~~Five~~A special ~~cases are needed to cover effective dates for individual lines which undergo transitions after the general effective date. These special cases cover the~~case covers effective dates for ~~those~~(1) lines ~~which are~~ initially becoming subject to the ~~standard, those~~Standard, (2) lines ~~which are~~ changing ~~their~~in applicability within the standard~~, and those lines which are changing in a manner that removes their applicability to the standard.~~.

~~Case 1~~The special case 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~~2015 may identify a line to have that designation beginning in PY ~~2021~~2025, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. ~~The table below has some explanatory examples of the application.~~

~~Date that Planning Study is completed~~	~~PY the line will become an IROL element~~	~~Date 1~~	~~Date 2~~	~~Effective Date The latter of Date 1 or Date 2~~
~~A05/15/2011~~	~~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

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improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Date that Planning Study is completed	PY the line will become an IROL element	Date 1	Date 2	Effective Date The later of Date 1 or Date 2
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 3 is needed because a line operating at 200 kV or above that once was designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network. Such changes result in the need to apply R1 to that line until that date is reached and then to apply R2 to that line thereafter.~~

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

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

Defined Terms:

Explanation for revising the definition of ROW:

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

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

Explanation for revising the definition of Vegetation ~~Inspections~~Inspection:

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

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

Explanation of the ~~definition~~derivation of the MVCD:

The MVCD is a calculated minimum distance that is derived from the Gallet ~~Equations~~equation. 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~~of the Standard provides MVCD values for various voltages and altitudes. ~~Details of the equations and an example calculation are~~

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~~provided~~The table is based on empirical testing data from EPRI as requested by FERC in ~~Appendix 1 of the Technical Reference Document.~~Order No. 777.

Project 2010-07.1 Adjusted MVCDs per EPRI Testing:
In Order No. 777, FERC directed NERC to undertake testing to gather empirical data validating the appropriate gap factor used in the Gallet equation to calculate MVCDs, specifically the gap factor for the flash-over distances between conductors and vegetation. See, Order No. 777, at P 60. NERC engaged industry through a collaborative research project and contracted EPRI to complete the scope of work. In January 2014, NERC formed an advisory group to assist with developing the scope of work for the project. This team provided subject matter expertise for developing the test plan, monitoring testing, and vetting the analysis and conclusions to be submitted in a final report. The advisory team was comprised of NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulation coordination, and vegetation management. The testing project commenced in April 2014 and continued through October 2014 with the final set of testing completed in May 2015. Based on these testing results conducted by EPRI, and consistent with the report filed in FERC Docket No. RM12-4-000, the gap factor used in the Gallet equation required adjustment from 1.3 to 1.0. This resulted in increased MVCD values for all alternating current system voltages identified. The adjusted MVCD values, reflecting the 1.0 gap factor, are included in Table 2 of version 4 of FAC-003.

The air gap testing completed by EPRI per FERC Order No. 777 established that trees with large spreading canopies growing directly below energized high voltage conductors create the greatest likelihood of an air gap flash over incident and was a key driver in changing the gap factor to a more conservative value of 1.0 in version 4 of this standard.

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

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

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Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations ~~as described more fully in the Technical Reference document~~.
These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

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

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

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

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~~The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will prevent transmission outages.~~
If the applicable Transmission Owner or applicable Generator Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

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

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

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

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

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

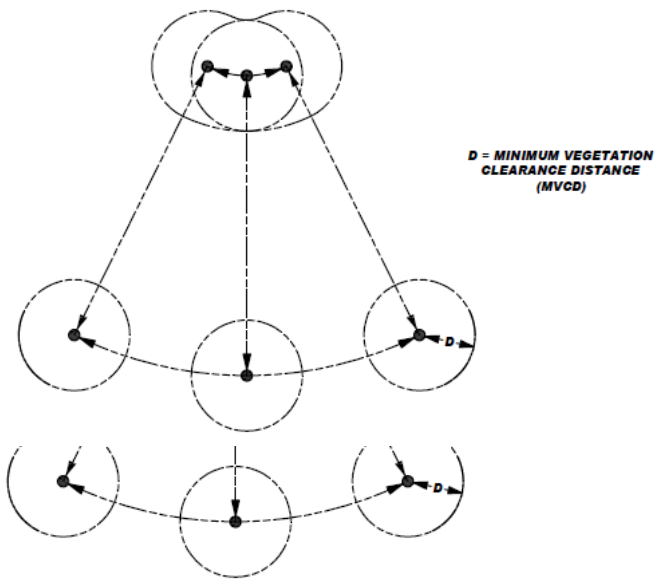

Figure 1

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

Requirement R4:
R4 is a risk-based requirement. -It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a

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vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

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

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

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

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

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

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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~~herbicides to control incompatible vegetation outside of the MVCD, but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

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

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

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

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

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

Requirement R7:

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

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

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

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

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

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

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~~FAC-003 – TABLE 2 – Minimum Vegetation Clearance Distances (MVCD)[24]~~

~~For **Alternating Current** Voltages (feet)~~

~~(AC) Nominal System Voltage (KV)~~	~~(AC) Maximum System Voltage (kV)[25]~~	~~MVCD (feet) Over sea level up to 500 ft~~	~~MVCD (feet) Over 500 ft up to 1000 ft~~	~~MVCD feet Over 1000 ft up to 2000 ft~~	~~MVCD feet Over 2000 ft up to 3000 ft~~	~~MVCD feet Over 3000 ft up to 4000 ft~~	~~MVCD feet Over 4000 ft up to 5000 ft~~	~~MVCD feet Over 5000 ft up to 6000 ft~~	~~MVCD feet Over 6000 ft up to 7000 ft~~	~~MVCD feet Over 7000 ft up to 8000 ft~~	~~MVCD feet Over 8000 ft up to 9000 ft~~	~~MVCD feet Over 9000 ft up to 10000 ft~~	~~MVCD feet Over 10000 ft up to 11000 ft~~
~~765~~	~~800~~	~~8.2ft~~	~~8.33ft~~	~~8.61ft~~	~~8.89ft~~	~~9.17ft~~	~~9.45ft~~	~~9.73ft~~	~~10.01ft~~	~~10.29ft~~	~~10.57ft~~	~~10.85ft~~	~~11.13ft~~
~~500~~	~~550~~	~~5.15ft~~	~~5.25ft~~	~~5.45ft~~	~~5.66ft~~	~~5.86ft~~	~~6.07ft~~	~~6.28ft~~	~~6.49ft~~	~~6.7ft~~	~~6.92ft~~	~~7.13ft~~	~~7.35ft~~
~~345~~	~~362~~	~~3.19ft~~	~~3.26ft~~	~~3.39ft~~	~~3.53ft~~	~~3.67ft~~	~~3.82ft~~	~~3.97ft~~	~~4.12ft~~	~~4.27ft~~	~~4.43ft~~	~~4.58ft~~	~~4.74ft~~
~~287~~	~~302~~	~~3.88ft~~	~~3.96ft~~	~~4.12ft~~	~~4.29ft~~	~~4.45ft~~	~~4.62ft~~	~~4.79ft~~	~~4.97ft~~	~~5.14ft~~	~~5.32ft~~	~~5.50ft~~	~~5.68ft~~
~~230~~	~~242~~	~~3.03ft~~	~~3.09ft~~	~~3.22ft~~	~~3.36ft~~	~~3.49ft~~	~~3.63ft~~	~~3.78ft~~	~~3.92ft~~	~~4.07ft~~	~~4.22ft~~	~~4.37ft~~	~~4.53ft~~
~~161*~~	~~169~~	~~2.05ft~~	~~2.09ft~~	~~2.19ft~~	~~2.28ft~~	~~2.38ft~~	~~2.48ft~~	~~2.58ft~~	~~2.69ft~~	~~2.8ft~~	~~2.91ft~~	~~3.03ft~~	~~3.14ft~~
~~138*~~	~~145~~	~~1.74ft~~	~~1.78ft~~	~~1.86ft~~	~~1.94ft~~	~~2.03ft~~	~~2.12ft~~	~~2.21ft~~	~~2.3ft~~	~~2.4ft~~	~~2.49ft~~	~~2.59ft~~	~~2.7ft~~
~~115*~~	~~121~~	~~1.44ft~~	~~1.47ft~~	~~1.54ft~~	~~1.61ft~~	~~1.68ft~~	~~1.75ft~~	~~1.83ft~~	~~1.91ft~~	~~1.99ft~~	~~2.07ft~~	~~2.16ft~~	~~2.25ft~~
~~88*~~	~~100~~	~~1.18ft~~	~~1.21ft~~	~~1.26ft~~	~~1.32ft~~	~~1.38ft~~	~~1.44ft~~	~~1.5ft~~	~~1.57ft~~	~~1.64ft~~	~~1.71ft~~	~~1.78ft~~	~~1.86ft~~

~~[24] 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.~~

~~[25] Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.~~

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69*	72	0.84ft	0.86ft	0.90ft	0.94ft	0.99ft	1.03ft	1.08ft	1.13ft	1.18ft	1.22ft	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)

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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

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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)

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TABLE 2 (CONT) Minimum Vegetation Clearance Distances (MVCD)[7]

For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	MVCD meters Over sea level up to 500 ft	MVCD meters Over 500 ft up to 1000 ft	MVCD meters Over 1000 ft up to 2000 ft	MVCD meters Over 2000 ft up to 3000 ft	MVCD meters Over 3000 ft up to 4000 ft	MVCD meters Over 4000 ft up to 5000 ft	MVCD meters Over 5000 ft up to 6000 ft	MVCD meters Over 6000 ft up to 7000 ft	MVCD meters Over 7000 ft up to 8000 ft	MVCD meters Over 8000 ft up to 9000 ft	MVCD meters Over 9000 ft up to 10000 ft	MVCD meters Over 10000 ft up to 11000 ft

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	~~(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)~~	~~15.83ft (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)~~	~~12.63ft (3.85m)~~	~~12.93ft (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)~~	~~10.93ft (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)~~

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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~~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~~used 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~~1 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

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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~~was approximately 2.0 per unit. This value ~~is~~was 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~~was 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~~was considered a realistic maximum.

The Gallet ~~Equations~~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~~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~~ Since no 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~~ existed at the time version 3 was developed, the SDT chose a proven method that has been used in other EHV applications. The Gallet equations

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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.

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

Table 7

(Table D.5 for feet)

(AC) Nom System Voltage (kV)	(AC) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 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

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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)

1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2)
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)
3) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

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

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

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

1. 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. 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. 3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.

4. 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.

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Rationale for R3:
The documentation provides a basis for evaluating the competency of the applicable Transmission Owner's or applicable Generator Owner's vegetation program. There may be many acceptable approaches to maintain clearances. -Any approach must demonstrate that the applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions. ~~See Figure~~

Rationale for R4:
This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

Rationale for R5:
Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

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

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

Rationale for R6:
Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

Rationale for R7:
This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

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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."	
3	May 9, 2012	Adopted by Board of Trustees	
3	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-003-3. This standard becomes enforceable on July 1, 2014 for Transmission Owners. For Generator Owners, R3	

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		~~becomes enforceable on January 1, 2015 and all other requirements (R1, R2, R4, R5, R6, and R7) will become enforceable on January 1, 2016.~~	
~~3~~	~~November 22, 2013~~	~~Updated the VRF for R2 from "Medium" to "High" per a Final Rule issued by FERC.~~	

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan for FAC-003-4 — Transmission Vegetation Management

Requested Approval
FAC-003-4 – Transmission Vegetation Management

Requested Retirement
FAC-003-3 – Transmission Vegetation Management

Prerequisite Approvals
None.

Defined Terms in the NERC Glossary
None.

Effective Date
Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 3 months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 3 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Compliance Note

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 later 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.

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.

Standard for Retirement

FAC-003-3 11:59:59 p.m. on the day immediately prior to the Effective Date of FAC-003-4 in the particular jurisdiction in which the FAC-003-4 standard is becoming effective.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan for FAC-003-4 — Transmission Vegetation Management

Requested Approval
FAC-003-4 – Transmission Vegetation Management

Requested Retirement
FAC-003-3 – Transmission Vegetation Management

Prerequisite Approvals
None.

Defined Terms in the NERC Glossary
None.

Effective Date
Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 3 months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 3 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Compliance Note

A line operated below 200kV, designated by the Planning ~~Authority~~ 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 lat~~t~~er of: 1) 12 months after the date the Planning Coordinator~~Authority~~ 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.

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.

Standard for Retirement

FAC-003-3 11:59:59 p.m. on the day immediately prior to the Effective Date of FAC-003-4 in the particular jurisdiction in which the FAC-003-4 standard is becoming effective.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project Vegetation Management
FAC-003-4

Final Ballot Open through February 8, 2016

Now Available

A final ballot for **FAC-003-4 - Transmission Vegetation Management** is open through **8 p.m. Eastern, Monday, February 8, 2016**.

Balloting

In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a vote. All ballot pool members may change their previously cast votes. A ballot pool member who failed to vote during the previous ballot period may vote in the final ballot period. If a ballot pool member does not participate in the final ballot, the member's vote from the previous ballot will be carried over as their vote in the final ballot.

Members of the ballot pool associated with this project may log in and submit their vote for the standard here. If you experience any difficulties in using the Standards Balloting & Commenting System (SBS), contact Nasheema Santos.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error message, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps

The voting results for the standard will be posted and announced after the ballot closes. If approved, the standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Sean Bodkin (via email), or at (202) 400-3022.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2010-07.1 Vegetation Management FAC-003-4

Final Ballot Results

Now Available

A final ballot for **FAC-003-4 Transmission Vegetation Management** concluded **8 p.m. Eastern, February 8, 2016.**

The standard received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides the detailed results.

Ballot
Quorum / Approval
90.03% / 96.18%

Next Steps
The standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For information on the Standards Development Process, refer to the Standard Processes Manual

For more information or assistance, contact Standards Developer, Sean Bodkin (via email), or at (202) 400-3022.

North American Electric Reliability Corporation
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BALLOT RESULTS

Ballot Name: 2010-07.1 Vegetation Management FAC-003-4 FN 2 ST
Voting Start Date: 1/29/2016 9:28:06 AM
Voting End Date: 2/8/2016 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 271
Total Ballot Pool: 301
Quorum: 90.03
Weighted Segment Value: 96.18

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	83	1	71	0.959	3	0.041	0	3	6
Segment: 2	3	0.3	3	0.3	0	0	0	0	0
Segment: 3	68	1	54	0.931	4	0.069	0	1	9
Segment: 4	18	1	16	1	0	0	0	0	2
Segment: 5	70	1	55	0.932	4	0.068	0	2	9
Segment: 6	47	1	40	0.93	3	0.07	0	0	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	3	0.3	3	0.3	0	0	0	0	0
Segment: 9	2	0.2	2	0.2	0	0	0	0	0

Segment: 10	7	0.7	7	0.7	0	0	0	0	0
Totals:	301	6.5	251	6.252	14	0.248	0	6	30

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Negative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	Andrew Pusztai		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	ATCO Electric	David Downey	Dan Bamber	Negative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A

1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Affirmative	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Bruce Bugbee		Affirmative	N/A
1	Colorado Springs Utilities	Shawna Speer		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Affirmative	N/A
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Doug Hils		None	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Georgia Transmission	Jason Snodgrass		Affirmative	N/A

	Corporation				
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	Iberdrola - Central Maine Power Company	Joe Turano		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A

1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Charles Raney		Abstain	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Rod Kinard	Tammy Porter	Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Peak Reliability	Jared Shakespeare		Abstain	N/A
1	PHI - Potomac Electric Power Co.	David Thorne		Affirmative	N/A
1	Platte River Power Authority	John Collins		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	Scott Smith		Negative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A

1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Sacramento Municipal Utility District	Tim Kelley	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		None	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Affirmative	N/A
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		Affirmative	N/A
1	Southwest Transmission Cooperative, Inc.	John Shaver		Affirmative	N/A
1	Sunflower Electric Power Corporation	Bertha Ellen Watkins		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A

1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Affirmative	N/A
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Shuye Teng		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Negative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Negative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Farmington	Linda Jacobson-Quinn		Negative	N/A
3	City of Redding	Elizabeth Hadley	Bill Hughes	None	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		None	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A

3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Chris Gowder	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	David Hadzima		None	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A

3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn		None	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Blaine Dinwiddie		None	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	PHI - Potomac Electric Power Co.	Mark Yerger		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Negative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A

3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		None	N/A
3	Sacramento Municipal Utility District	Rachel Moore	Joe Tarantino	Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		None	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Jim Cox		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		None	N/A
3	WEC Energy Group, Inc.	James Keller		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	Blue Ridge Power	Duane Dahlquist		Affirmative	N/A

	Agency				
4	City of Redding	Nick Zettel	Bill Hughes	None	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		Affirmative	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh	John Reed	Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Michael Ramirez	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public	Stephanie Little		Affirmative	N/A

	Service Co.				
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Avista - Avista Corporation	Steve Wenke		Negative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	BC Hydro and Power Authority	Clement Ma		None	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Abstain	N/A
5	City and County of San Francisco	Daniel Mason		Negative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Mike Hirst		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		None	N/A

5	Edison International - Southern California Edison Company	Michael McSpadden		Affirmative	N/A
5	EDP Renewables North America LLC	Heather Morgan		Affirmative	N/A
5	Essential Power, LLC	Gerry Adamski		None	N/A
5	Exelon	Vince Catania		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann	Chris Gowder	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Lower Colorado River Authority	Dixie Wells		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A

5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	NB Power Corporation	Rob Vance		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		None	N/A
5	Oglethorpe Power Corporation	Teresa Czyz		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Dan Wilson		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A

5	SCANA - South Carolina Electric and Gas Co.	Henry Delk		None	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Negative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A
5	U.S. Bureau of Reclamation	Erika Doot		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	stephanie johnson		Affirmative	N/A
5	Xcel Energy, Inc.	David Lemmons		Affirmative	N/A
6	AEP - AEP Marketing	Edward P Cox		None	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	N/A
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A

6	City of Redding	Marvin Briggs	Bill Hughes	None	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Louis Slade		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Edison International - Southern California Edison Company	Earle Saunders		Affirmative	N/A
6	Exelon	Dave Carlson		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Chris Gowder	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Iberdrola - New York State Electric and Gas Corporation	Julie King		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik	Simon Tanapat	Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power	Shivaz Chopra		Affirmative	N/A

	Authority				
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Affirmative	N/A
6	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
6	Platte River Power Authority	Carol Ballantine		Affirmative	N/A
6	Portland General Electric Co.	Shawn Davis		Negative	N/A
6	PPL - Louisville Gas and Electric Co.	OELKER LINN		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		Affirmative	N/A
6	Sacramento Municipal Utility District	Diane Clark	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Kenn Backholm		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	John J. Ciza		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Brad Lisembee		Affirmative	N/A
6	Tacoma Public Utilities	Rick Applegate		Affirmative	N/A

	(Tacoma, WA)				
6	Talen Energy Marketing, LLC	Elizabeth Davis		Negative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Megan Wagner		Affirmative	N/A
6	Xcel Energy, Inc.	Peter Colussy	Amy Casuscelli	Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel	Chris Gowder	Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A

Exhibit G

Standard Drafting Team Roster

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Drafting Team Roster

Project 2010-07.1 Vegetation Management (FAC-003)

	Participant	Entity
Chair	Ron Adams	Duke Energy
Vice Chair	Eric Engdahl	American Electric Power
Member	Donald L. Woods	Entergy Services, Inc.
Member	Matthew T. Goodnight	Salt River Project
Member	Scott Lee	Oncor Electric Delivery
Member	Ian Evans	Westar Energy
Member	Katrina Schnobrich	FirstEnergy Corporation
Member	Jason Regg	TVA
Member	Frank Mangiamele	Consolidated Edison
PMOS	Andrew Gallo	City of Austin dba Austin Energy
NERC Staff	Sean Bodkin (Standards Developer)	NERC
NERC Staff	Jordan Mallory (Standards Developer)	NERC
NERC Staff	Candice Castaneda (NERC Legal)	NERC