NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Transmission Vegetation Management

Standard FAC-003-2 Technical Reference

Prepared by the

North American Electric Reliability Corporation

Vegetation Management Standard Drafting Team for NERC Project 2007-07

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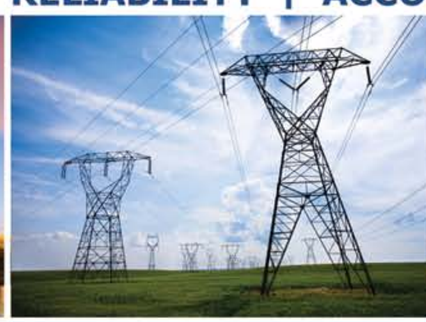
RELIABILITY | ACCOUNTABILITY



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Disclaimer

This supporting document is supplemental to the reliability standard FAC-003-2 — Transmission Vegetation Management and does not contain mandatory requirements subject to compliance review. Throughout this document, for ready reference, there are “copies” in italic font of the wording in the Standard. Any “copy” of any part of the Standard in this document should be cross checked to the Standard and if any difference exists, then the Standard’s exact wording should be considered the intended wording for this document.

Introduction

This document is intended to provide supplemental information and guidance for complying with the requirements of Reliability Standard FAC-003-2.

The purpose of the Standard is to improve the reliability of the electric transmission system by preventing those vegetation related outages that could lead to Cascading.

Compliance with the Standard is mandatory and enforceable.

Special Note: The Application of the Results-Based Approach to FAC-003-2

In its three-year assessment as the ERO, NERC acknowledged stakeholder comments and committed to:

i) addressing quality issues to ensure each reliability standard has a clear statement of purpose, and has outcome-focused requirements that are clear and measurable; and
ii) eliminating requirements that do not have an impact on bulk power system reliability.

In 2010, the Standards Committee approved a recommendation to use Project 2007-07 Vegetation Management as a first proof of concept for developing results-based standards.

This standard is not intended to address outages such as those due to vegetation fall-ins or blow-ins from outside the Right-of-Way, vandalism, human activities or acts of nature. Operating experience indicates that trees that have grown out of specification have contributed to Cascading, especially under heavy electrical loading conditions.

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

a) Performance-based — defines a particular reliability objective or outcome to be achieved. 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 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 *<u>that reduces a stated risk to the reliability of the bulk power system</u>*?
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 <u>of the bulk power system</u>*?

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 NERC Vegetation Management Standard (“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.

The 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.

The 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.

The drafting team reviewed and edited version 1 of FAC-003-1 to remove prescriptive and administrative language in order to distill the technical requirements down to their essential reliability content. Explanatory text is offered within two special sections, Background and Guideline and Technical Basis, to aid in understanding the standard and its requirements. Rationale text boxes and other text boxes are also inserted throughout the standard to aid understanding the sections. The Effective Dates section covers five special cases for lines that undergo specific transitions as or after the standard has reached the general effective date.

Preface

The NERC Vegetation Management Standard Drafting Team (VM SDT) acknowledges those across the industry who contributed to the development of this Standard and companion Technical Reference document. This Technical Reference document is intended to provide supplemental explanatory background and guidance related to requirements contained in the Standard but does not in itself contain requirements subject to compliance review.

The Standard requires the Transmission Owner to have documentation of the maintenance strategies or procedures or processes or specifications it uses to be successful in managing vegetation. This allows the Transmission Owner to exercise substantial flexibility in designing its overall program to meet its specific needs provided that the Transmission Owner also meets the purpose of the Standard.

While there are many approaches to vegetation management, the VMSDT supports industry best practices contained in ANSI A300 (Part 7) – Integrated Vegetation Management (IVM) practices on Utility Rights-of-way, as well as the companion publication Best Management Practices – Integrated Vegetation Management, as an effective strategy to maintain compliance with this Standard. ANSI A300 (Part 7), approved by industry consensus in 2006, contains many elements needed for an effective vegetation management. Those elements are similar to the requirements in this Standard. One key element is the "wire zone – border zone" concept. Supported by over 50 years of continuous research, wire zone – border zone is a proven method to manage vegetation on transmission rights-of-ways and is an industry accepted best practice to help ensure electric system reliability.

The VM SDT believes that Transmission Owners who adopt and effectively implement IVM principles, particularly the "wire zone – border zone" concept, are far less likely to experience a vegetation caused outage than those who do not.

Effective Dates & Special States of Transition

The first sentence of the Effective Dates section is standard language used in most NERC standards to cover the general effective date and is sufficient to cover the vast majority of situations. Five special cases are needed to cover effective dates for individual lines which undergo transitions after the general effective date. These special cases cover the effective dates for those lines which are initially becoming subject to the standard, those lines which are changing their applicability within the standard, and those lines which are changing in a manner that removes their applicability to the standard. The text for each of these five cases is copied from the standard and is shown below in italic font. An explanation of the need for each special exception follows each copied text section.

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.*

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

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

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.*

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.

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*

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.

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.*

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

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.*

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

Definition of Terms

Right-of-Way (ROW)*

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria.

> The current glossary definition of this NERC term is modified to address the issues set forth in Paragraph 734 of FERC Order 693.

The current NERC glossary definition of Right of Way has been modified to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This modified definition represents a slight but significant departure from the strict legal definition of "right of way" in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included 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.

This definition does not imply that danger tree rights beyond the constructed and maintained width are incorporated in the definition; therefore fall-ins from outside the ROW but within an area with danger tree rights would not be considered fall-ins from within the ROW.

Vegetation Inspection*

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

> The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.
>
> Current definition of Vegetation Inspection: The systematic examination of a transmission corridor to document vegetation conditions.

The inspection includes the identification of any vegetation that may pose a threat to reliability prior to the next planned maintenance or inspection work, considering the current location of the conductor and other possible locations of the conductor due to sag and sway for rated conditions.

This definition allows both maintenance inspections and vegetation inspections to be performed concurrently.

* This is a modification to a defined term in the NERC glossary and will be incorporated into the NERC glossary of terms with final approval of this standard revision.

See the Guidelines and Technical Basis section on Requirement R6 contained within the Standard for more details on inspections.

Minimum Vegetation Clearance Distance (MVCD)

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

The MVCD is a calculated minimum distance that is derived from the Gallet Equations. This is a method has been 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 Figures 1, 2 and 3. Details of the equations and an example calculation are provided in Appendix 1below of the Technical Reference document. Table 1in Appendix 1 below provides MVCD values for various voltages and altitudes.

Applicability of the Standard

4. Applicability

4.1. ***Functional Entities:***
Transmission Owners

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 lines operated at 200kV or higher.*

4.2.2 *Each overhead transmission lines 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 lines operated below 200 kV identified as an element of a Major WECC Transfer Paths 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. ***Enforcement:*** *The reliability obligations of the applicable entities and facilities are contained within the technical requirements of this standard*

Rationale

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

In Order 693, FERC discussed the 200 kV bright-line test of applicability. While FERC did not change the 200 kV bright-line, the Commission remained concerned that there may be some transmission lines operating at lesser voltages that could have significant impact on the Bulk Electric System that should therefore be subject to this standard.

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

NERC Standard FAC-014 has the stated purpose, "*To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies."* FAC-014 requires Reliability Coordinators, Planning Coordinators, and Transmission Planners to have a methodology to identify all lines that might comprise an IROL. Thus, these entities would identify sub-200 kV lines that qualify as part of an IROL and should be subject to FAC-003-2.

Although all three entities may prepare the list of elements, the list as provided by the Planning Coordinator function is the more appropriate choice for this Standard. The Time Horizon needed to plan vegetation management work does not lend itself to the operating horizon of a Reliability Coordinator. Additionally, the Planning Coordinator has a wider-area view than the Transmission Planner and could thus identify any elements of importance to a sub-set of its area that might be missed by a Transmission Planner.

Transmission Owners, who do not already get the list of circuits included in the definition of an IROL, can get them from the Planning Coordinator. Specifically R5 of FAC-014 specifies that "*The Reliability Coordinator, Planning Authority (Coordinator) and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits"*

Vegetation-related Sustained Outages that occur due to natural disasters are beyond the control of the Transmission Owner. These events are not classified as vegetation-related Sustained Outages and are therefore exempt from the Standard. Transmission lines are not designed to withstand the impacts of natural disasters such as flood, drought, earthquake, major storms, fire, hurricane, tornado, landslides, ice storms, etc. In the aftermath of catastrophic system damage from natural disasters the Transmission Owner's focus is on electric system restoration for public safety and critical support infrastructure.

Sustained Outages due to human or animal activity are beyond the control of the Transmission Owner. These outages are not classified as vegetation-related Sustained Outages and are therefore exempt from the Standard. Examples of these events may include new plantings by outside parties of tall vegetation under the transmission line planted since the last Vegetation Inspection, tree contacts with line initiated by vehicles, logging activities, etc.

The foregoing exemptions are addressed in a new footnote 2. Referred to collectively as force majeure events and activities, this footnote applies to requirements R1 and R2 in FAC-003-2.

The reliability objective of this NERC Vegetation Management Standard ("Standard") is to prevent vegetation-related outages which could lead to Cascading by effective vegetation maintenance while recognizing that certain outages such as those due to vandalism, human errors and acts of nature are not preventable. Operating experience clearly indicates that trees that have grown out of specification could contribute to a cascading grid failure, especially under heavy electrical loading conditions.

Serious outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. To properly reduce and manage this risk, it is necessary to apply the Standard to 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. For the purposes of the Standard and this Technical Reference document, the term “public lands” includes municipal lands, village lands, city lands, and land owned by a host of other governmental entities.

The Standard addresses vegetation management along applicable overhead lines that serve to connect one electric station to another. However, it is not intended to be applied to lines sections inside the electric station fence or other boundary of an electric station, submarine or underground lines.

The Standard is intended to reduce the risk of Cascading involving vegetation. It is not intended to prevent customer outages from occurring due to tree contact with all transmission lines and voltages. 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 Bulk Electric System.

Vegetation growth is constant and always present. Unmanaged vegetation below numerous transmission lines that are operating at or near their Rating is highly problematic. This situation has led to multiple subsequent line failures and Cascading. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are statistically intermittent. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this Standard’s emphasis is on vegetation grow-ins.

In preparing the original vegetation management standard in 2005, industry stakeholders set the threshold for applicability of the standard at 200kV. This was because an unexpected loss of lines operating at above 200kV has a higher probability of initiating a widespread blackout or cascading outages compared with lines operating at less than 200kV.

The original NERC Standard FAC-003-1 also allowed for application of the standard to “critical” circuits (critical from the perspective of initiating widespread blackouts or cascading outages) operating below 200kV. While the percentage of these circuits is relatively low, it remains a fact that there are sub-200kV circuits whose loss could contribute to a widespread outage. Given the very limited exposure and unlikelihood of a major event related to these lower-voltage lines, it would be an imprudent use of resources to apply the Standard to all sub-200kV lines. The drafting team, after evaluating several alternatives, selected the IROL and WECC Major Transfer Path criteria to determine applicable lines below 200 kV that are subject to this standard.

Requirements R1 and R2

R1. Each Transmission 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 its Rating and all Rated Electrical Operating Conditions of the types shown below[2]:

1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage[3],
2. An encroachment due to a fall-in from inside the Right-of-Way (ROW) that caused a vegetation-related Sustained Outage[4],
3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[4],
4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage[4].

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

Rationale for R1 and R2:

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

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

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.

2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.

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

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

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

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

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

Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[2]:

1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage[3],
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage[4],
3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[4],
4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage[4]

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

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

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the prevention of vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each Transmission Owner to manage vegetation to prevent encroachment within the 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 <u>not</u> an element of an IROL, and <u>not</u> an element of a Major WECC Transfer Path.

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

R1 and R2 state that if vegetation encroaches within the distances in Table 1 in Appendix 1 of this supplemental Technical Reference document, it is in violation of the standard. Table 1below, which is the same as Table 2 in the standard, tabulates the distances necessary to prevent spark-over based on the Gallet equations as described more fully in Appendix 1 below.

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

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

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

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

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

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

Requirement R3

Rationale

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

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

3.1 *Movement of applicable line conductors under their Facility 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 Transmission Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)*

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

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

An example of one approach commonly used by industry is ANSI Standard A300, part 7.

However, regardless of the approach a utility uses to manage vegetation, any approach a Transmission Owner chooses to use will generally contain the following elements:

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

4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figures 1, 2, and 3 below.

Conductor Dynamics

In order for a Transmission Owner to develop a specific maintenance approach, it is important to understand the dynamics of a line conductor's movements. This paper will first address the complexities inherent in observing and predicting conductor movement, particularly for field personnel. It will then present some examples of maintenance approaches which Transmission Owners may consider that take into account these complexities, and the practical approaches that can be utilized by field personnel.

Additionally, it is important the Transmission Owner consider all conductor locations, the MVCD, and vegetation growth between maintenance activities when developing a maintenance approach.

Understanding Conductor Position and Movement

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

As a consequence of these loading variables, the conductor's position in space is dynamic and moving. When calculating the range of conductor positions, the Transmission Owner should use the same design criteria and assumptions that are used to establish Ratings and System Operating Limits (SOLs), as described in other standards. Typically, the greatest conductor movements occur at mid-span. As the conductor moves through various positions, a spark-over zone surrounding the conductor moves with it. The radius of the spark-over zone may be found by referring to Table 1 below. For illustrations of this zone and conductor movements, Figures 1, 2 and 3 below are provided. At the time of making a field observation, however, it is very difficult to precisely know where the conductor is in relation to its wide range of all possible positions. Therefore, Transmission Owners must adopt maintenance approaches that account for this dynamic situation.

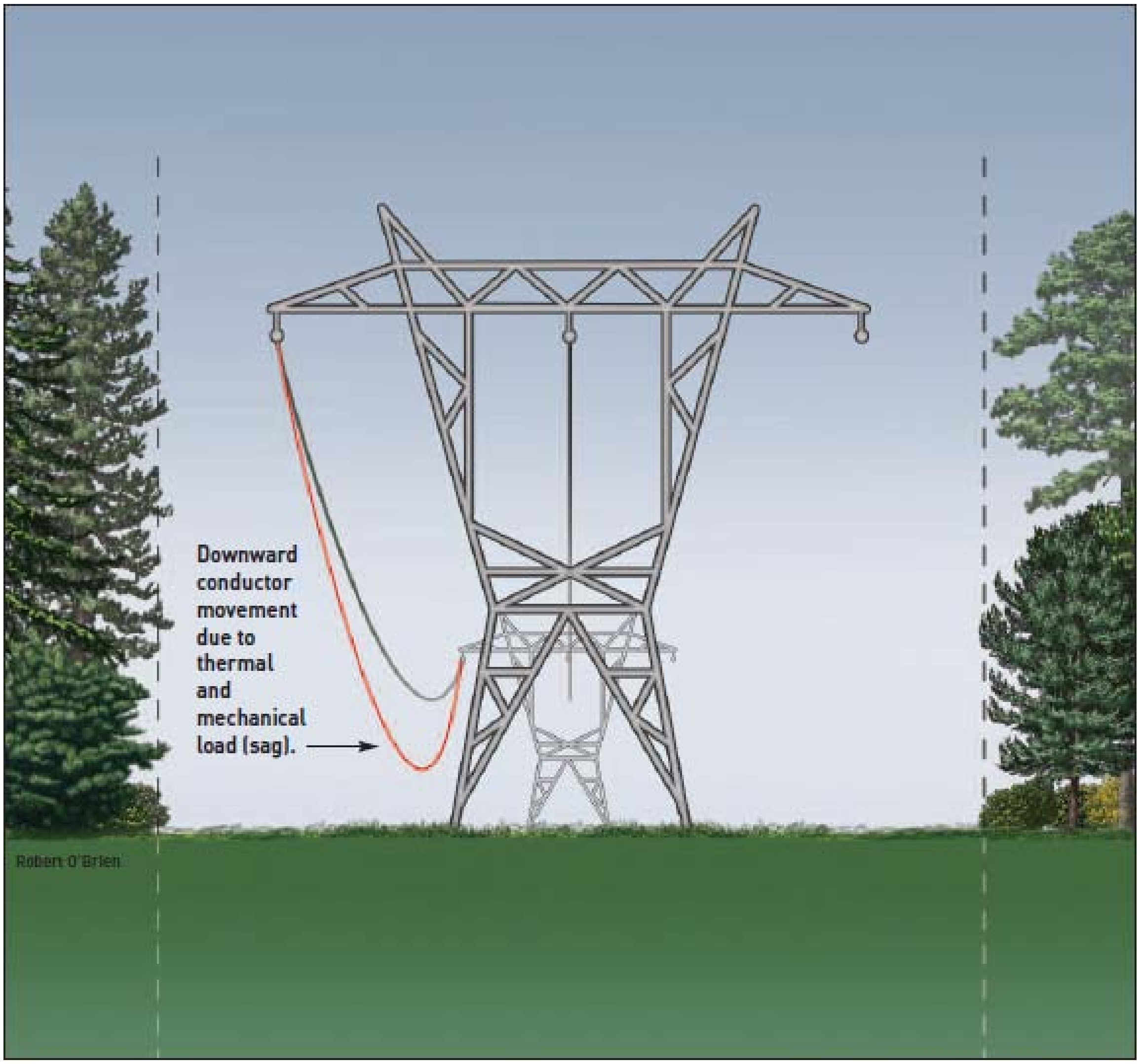
Downward
conductor
movement
due to
thermal
and
mechanical
load (sag).
Robert O'Brien

Figure 1

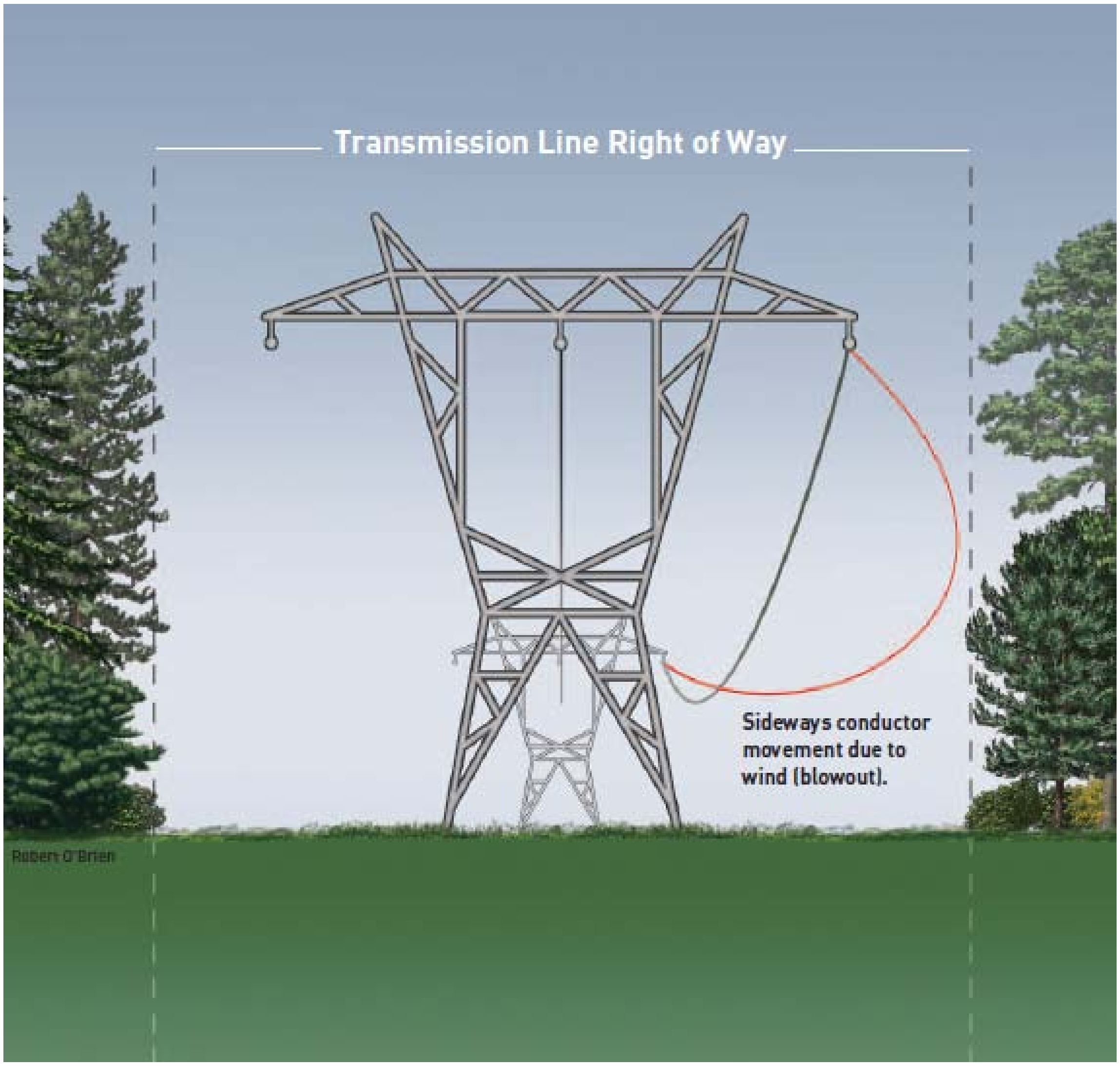
Transmission Line Right of Way
Sideways conductor
movement due to
wind (blowout).
Robert O'Brien

Figure 2

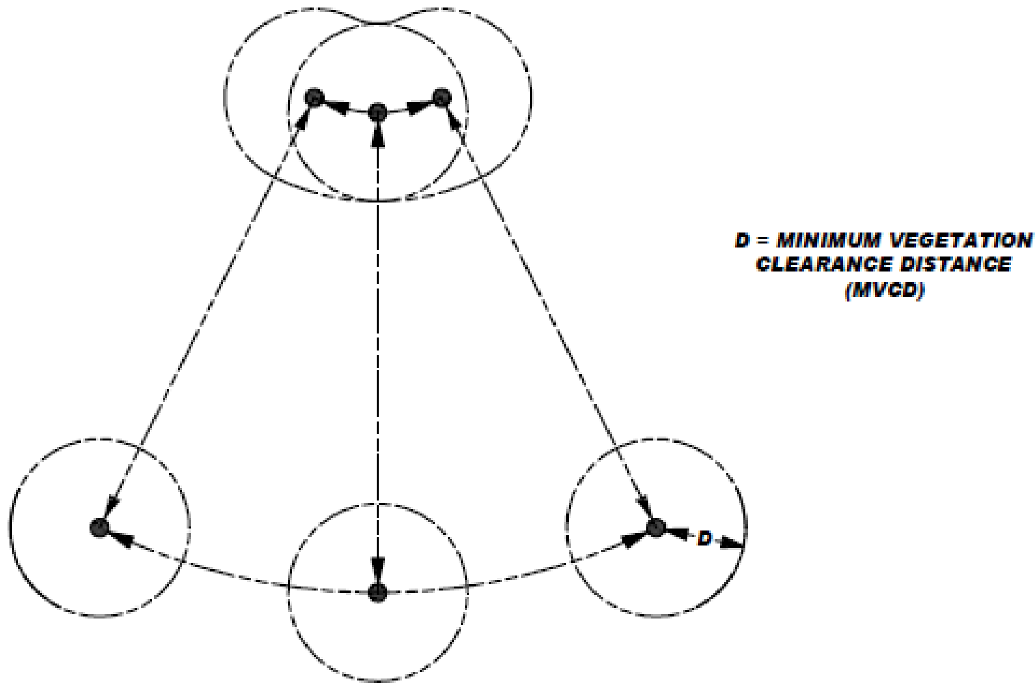

Figure 3

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.

Selecting a Maintenance Approach

In order to maintain adequate separation between vegetation and transmission line conductors, the Transmission Owner must craft a maintenance strategy that keeps vegetation well away from the spark-over zone mentioned above. In fact, it is generally necessary to incorporate a variety of maintenance strategies. For example, one Transmission Owner may utilize a combination of routine cycles, traditional IVM techniques and long-term planning. Another Transmission Owner may place a higher reliance on frequent inspections and follow-up remediation as opposed to a set cyclical approach. This variation of approaches is further warranted when factors, such as terrain, vegetation types, weather and climate, and any, environmental, legal or other land use constraints, must be considered in developing a Transmission Owner's specific approach to satisfying R3.

The following describes some strategies which may be utilized by a Transmission Owner. A Transmission Owner's basic maintenance approach in relatively flat terrain could be to remove all incompatible vegetation from the ROW if it has the right to do so and has no constraints. In mountainous terrain, however, this strategy could change to managing vegetation based on vegetation-to-conductor clearances, since it might not be necessary to remove vegetation in a valley that is far below the conductors at maximum sag.

If faced with easement constraints on a line design with sufficient ground clearance, the approach could be to allow vegetation such as fruit trees, but only up to a given height at maturity (for example 10 feet from the ground). If constraints cannot be overcome and if design clearances are sufficient, an exception to the Transmission Owner's 10-foot guideline might be made. If an approach is chosen to manage vegetation based primarily on clearance distances it could include an inspection regimen to regularly ensure that impending clearance problems are identified early for rectification.

ANSI A300 – Best Management Practices for Tree Care Operations

A description of ANSI A-300, part 7, is offered below to illustrate another maintenance approach that could be used in developing a comprehensive transmission vegetation management program.

Introduction

Integrated Vegetation Management (IVM) is a best management practice conveyed in the American National Standard for Tree Care Operations, Part 7 (ANSI 2006) and the International Society of Arboriculture *Best Management Practices: Integrated Vegetation Management* (Miller 2007). IVM is consistent with the requirements in FAC-003-02, and it provides practitioners with what industry experts consider to be appropriate techniques to apply to electric right-of-way projects in order to meet or exceed the Standard.

IVM is a system of managing plant communities whereby managers set objectives; identify compatible and incompatible vegetation; consider action thresholds; and evaluate, select and implement the most appropriate control method or methods to achieve set objectives. The choice of control method or methods should be based on the environmental impact and anticipated effectiveness; along with site characteristics, security, economics, current land use and other factors.

Planning and Implementation

Best management practices provide a systematic way of planning and implementing a vegetation management program. While designed primarily with transmission systems in mind, it is also applicable to distribution projects. As presented in ANSI A300 part 7 and the ISA best management practices, IVM consists of 6 elements:

1) Set Objectives
2) Evaluate the Site
3) Define Action Thresholds
4) Evaluate and Select Control Methods
5) Implement IVM
6) Monitor Treatment and Quality Assurance

The setting of objectives, defining action thresholds, and evaluating and selecting control methods all require decisions. The planning and implementation process is cyclical and continuous, because vegetation is dynamic and managers must have the flexibility to adjust their plans. Adjustments may be made at each stage as new information becomes available and circumstances evolve.

Set Objectives

Objectives should be clearly defined and documented. Examples of objectives can include promoting safety, preventing sustained outages caused by vegetation growing into electric facilities, maintaining regulatory compliance, protecting structures and security, restoring electric service during emergencies, maintaining access and clear lines of sight, protecting the environment, and facilitating cost effectiveness. Objectives should be based on site factors, such as workload and vegetation type, in addition to human, equipment and financial resources. They will vary from utility to utility and project to project, depending on line voltage and criticality, as well as topographical, environmental, fiscal and political considerations. However, where it is appropriate, the overriding focus should be on environmentally-sound, cost effective control of species that potentially conflict with the electric facility, while promoting compatible, early successional, sustainable plant communities.

Work Load Evaluations

Work-load evaluations are inventories of vegetation that could have a bearing on management objectives. Work load assessments can capture a variety of vegetation characteristics, such as location, height, species, size and condition, hazard status, density and clearance from conductors. Assessments should be conducted considering voltage, conductor sag from ambient temperatures and loading, and the potential influence of wind on line sway.

Evaluate and Select Control Methods

Control methods are the process through which managers achieve objectives. The most suitable control method best achieves management objectives at a particular site. Many cases call for a combination of methods. Managers have a variety of controls from which to choose, including manual, mechanical, herbicide and tree growth regulators, biological, and cultural options.

Manual Control Methods

Manual methods employ workers with hand-carried tools, including chainsaws, handsaws, pruning shears and other devices to control incompatible vegetation. The advantage of manual techniques is that they are selective and can be used where others may not be. On the other hand, manual techniques can be inefficient and expensive compared to other methods.

Mechanical Control Methods

Mechanical controls are done with machines. They are efficient and cost effective, particularly for clearing dense vegetation during initial establishment, or reclaiming neglected or overgrown right of way. On the other hand, mechanical control methods can be non-selective and disturb sensitive sites.

Tree Growth Regulator and Herbicide Control Methods

Tree growth regulators and herbicides can be effective for vegetation management. Tree growth regulators (TGRs) are designed to reduce growth rates by interfering with natural plant processes. TGRs can be helpful where removals are prohibited or impractical by reducing the growth rates of some fast-growing species.

Herbicides control plants by interfering with specific botanical biochemical pathways. Herbicide use can control individual plants that are prone to re-sprout or sucker after removal. When trees that re-sprout or sucker are removed without herbicide treatment, dense thickets develop, impeding access, swelling workloads, increasing costs, blocking lines-of-site, and deteriorating wildlife habitat. Treating suckering plants allows early successional, compatible species to dominate the right-of-way and out-compete incompatible species, ultimately reducing work.

Cultural Control Methods

Cultural methods modify habitat to discourage incompatible vegetation and establish and manage desirable, early successional plant communities. Cultural methods take advantage of seed banks of native, compatible species lying dormant on site. In the long run, cultural control is the most desirable method where it is applicable.

A cultural control known as cover-type conversion provides a competitive advantage to short-growing, early successional plants, allowing them to thrive and eventually out-compete unwanted tree species for sunlight, essential elements and water. The early successional plant community is relatively stable, tree-resistant and reduces the amount of work, including herbicide application, with each successive treatment.

Wire-Border Zone

The wire-border zone technique is a management philosophy that can be applied through cultural control. W.C. Bramble and W.R. Byrnes developed it in the mid-1980s out of research begun in 1952 on a transmission right-of-way in the Pennsylvania State Game Lands 33 Research and Demonstration project (Yahner and Hutnik (2004).

The wire zone is the section of a utility transmission right-of-way directly under the wires and extending outward about 10 feet on each side. The wire zone is managed to promote a low-growing plant community dominated by grasses, herbs and small shrubs (under 3 feet in height at maturity). The border zone is the remainder of the right-of-way. It is managed to establish small trees and tall shrubs (under 25 feet in height at maturity). When properly managed, diverse, tree-resistant plant communities develop in wire and border zones. The communities not only protect the electric facility and reduce long-term maintenance, but also enhance wildlife habitat, forest ecology and aesthetic values.

Although the wire-border zone is a best practice in many instances, it is not necessarily universally suitable. For example, standard wire-border zone prescriptions may be unnecessary where lines are high off the ground, such as across low valleys or canyons, so the technique can be modified without sacrificing reliability.

One way to accommodate variances in topography is to establish different regions based on wire height. For example, over canyon bottoms or other areas where conductors are 100 feet or more above the ground, only a few trees are likely to be tall enough to conflict with the lines. In those cases, trees that potentially interfere with the transmission lines can be removed selectively on a case-by-case basis.

In areas where the wire is lower, perhaps between 50-100 feet from the ground, a border zone community can be developed throughout the right-of-way. Note that in many cases, conductor attachment points are more than 50 feet off the ground, so a border zone community can be cultivated near structures. Where the line is less than 50 feet off the ground, managers could apply a full wire-border zone prescription.

An environmental advantage of this type of modification is stream protection. Streams often course through the valleys and canyons where lines are likely to be elevated. Leaving timber or border zone communities in canyon bottoms helps shelter this valuable habitat, enabling managers to achieve environmentally sensitive objectives.

Implement IVM

All laws and regulations governing IVM practices and specifications written by qualified vegetation managers must be followed. Integrated vegetation management control methods should be implemented on regular work schedules, which are based on established objectives and completed assessments. Work should progress systematically, using control measures determined to be best for varying conditions at specific locations along a right-of-way. Some considerations used in developing schedules include the importance and type of line, vegetation clearances, workloads, growth rate of predominant vegetation, geography, accessibility, and in some cases, time lapsed since the last scheduled work.

Clearances Following Work

Clearances following work should be sufficient to meet management objectives, including preventing trees from entering the Minimum Vegetation Clearance Distance, electric safety risks, service-reliability threats and cost.

Monitor Treatment and Quality Assurance

An effective program includes documented processes to evaluate results. Evaluations can involve quality assurance while work is underway and after it is completed. Monitoring for quality assurance should begin early to correct any possible miscommunication or misunderstanding on the part of crewmembers. Early and consistent observation and evaluation also provides an opportunity to modify the plan, if need be, in time for a successful outcome.

Utility vegetation management programs should have systems and procedures in place for documenting and verifying that vegetation management work was completed to specifications. Post-control reviews can be comprehensive or based on a statistically representative sample. This final review points back to the first step and the planning process begins again.

Summary of A-300 example

Integrated Vegetation Management offers among others, a systematic way of planning and implementing a vegetation management program as presented in ANSI A300 Part 7. This methodology enables a program to comply with the NERC *Transmission Vegetation Management Program* standard (FAC-003-2). Managers should select control options to best promote management objectives.

Vegetation Inspections

The standard in R6 establishes the frequency of vegetation inspections. These inspections can be used to "evaluate the site" as referred to in the second element of ANSI A300 Part 7. This necessary frequency may need to be less than the annually based on anticipated growth rates of the local vegetation, length of the growing season for the geographical area, limited ROW width, rainfall amounts, etc.

Annual Work Plan

Requirement R7 of the Standard addresses the execution of the annual work plan. A comprehensive approach that exercises the full extent of legal rights is superior to incremental management in the long term because it reduces overall encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient at all locations on the ROW. Removal is superior to pruning. Removal minimizes the possibility of conflicts between energized conductors and vegetation. When this is not possible, the approach should be to use vegetation maintenance methods to work towards or achieve the maximum use of the ROW.

Requirement R4

R4. *Each Transmission Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable transmission line when the Transmission Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment.*

> **Rationale**
>
> This is to ensure expeditious communication between the Transmission Owner and the control center when a critical situation is confirmed.

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

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

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

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

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

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

Requirement R5

R5. *When a Transmission Owner is constrained from performing vegetation work on an applicable line operating within their Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the Transmission Owner shall take corrective action to ensure continued vegetation management to prevent encroachments.*

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

Rationale

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

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

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

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

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

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

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

Requirement R6

R6. *Each Transmission Owner shall perform a Vegetation Inspection of 100% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 months between inspections on the same ROW.*[5]

M6. *Each Transmission Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 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)*

Rationale

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

R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections that fits general industry practice. In addition, the fact that Vegetation Inspections can be performed in conjunction with general line inspections further facilitates a Transmission Owner's ability to meet this requirement. However, the Transmission Owner may determine that more frequent inspections are needed to maintain reliability levels, dependent upon such factors as anticipated growth rates of the local vegetation, length of the growing season for the geographical area, limited ROW width, and rainfall amounts. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

Footnote 5 is added to address the situation where a Transmission Owner through no fault of its own, would be unable to complete the vegetation inspection within the allotted time period. This would include the situation of mutual aid as well as disasters to the Transmission Owner's own system.

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

The VSL for Requirement R6 has VSL categories ranked by the percentage of the required ROW inspections completed. To calculate the percentage of inspection completion, the Transmission Owner may choose units such as: line miles or kilometers, circuit miles or kilometers, pole line miles, ROW miles, etc.

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

The “Low VSL” for R6 would apply in this example.

Requirement R7

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

- Change in expected growth rate/ environmental factors
- Circumstances that are beyond the control of a Transmission Owner[6]
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Emerging technologies

Rationale

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

M7. *Each Transmission Owner has evidence that it completed its annual vegetation work plan. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (including modifications if any), dated work orders, dated invoices, or dated inspection records. (R7)*

R7 is a risk-based requirement. The Transmission Owner is required to implement its 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

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

work plan requirement is not intended to necessarily require a “span-by-span”, or even a “line-by-line” detailed description of all work to be performed. It is only intended to require that the Transmission Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

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

The ability to modify the work plan allows the Transmission Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance or work may be deferred to a subsequent year because of slower-than-expected growth. This situation may also include complying with mutual assistance agreements by moving resources off the Transmission Owner’s system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan. Modifications to the annual work plan must always ensure the reliability of the electric Transmission system.

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

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

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

Appendix 1: Clearance Distance Derivation by the Gallet Equation

The Gallet Equation is a well-known method of computing the required strike distance for proper insulation coordination, and has the ability to take into account various air gap geometries, as well as non-standard atmospheric conditions. When the Gallet Equation and conservative probabilistic methods are combined, i.e. deterministic design, spark-over probabilities of 10^{-6} or less are achieved. This approach is well known for its conservatism and was used to design the first 500 kV and 765 kV lines in North America [1]. Thus, the deterministic design approach using the Gallet Equation is used for the standard to compute the minimum strike distance between transmission lines and the vegetation that may be present in or along the transmission corridor.

Method Explanation (Gallet Equation)

In 1975 G. Gallet published a benchmark paper that provided a method to compute the critical flashover voltage (CFO) of various air gap geometries [4]. The Gallet Equation uses various "gap factors" to take into account various air gap geometries. Various gap factor values are provided in [1]. If the vegetation in a transmission corridor, e.g. a tree, is assumed electrically to be a large structure then the CFO of such an air gap geometry can be computed for dry or wet conditions using a well established equation proposed by Gallet [1],[2],[4],

$$CFO_A = k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} \qquad (1)$$

where,

k_w is defined as the factor that takes into account wet or dry conditions (dry = 1.0 and wet = 0.96) and phase arrangement (multiply by 1.08 for outside phase), e.g. outside phase and wet conditions = (0.96)(1.08) = 1.037,

k_g is defined as the gap factor (1.3 for conductor to large structure),

D is the strike distance (m),

CFO_A is the CFO for the relative air density (kV).

δ is defined as the relative air density and is approximately equal to (2) where *A* is the altitude in km,

$$\delta = e^{-\frac{A}{8.6}} \tag{2}$$

$$m = 1.25G_0\left(G_0 - 0.2\right) \tag{3}$$

$$G_0 = \frac{CFO_s}{500 \cdot D} \tag{4}$$

$$CFO_s = k_w \cdot k_g \cdot \frac{3400}{1 + \frac{8}{D}} \tag{5}$$

where CFO_S is the CFO for standard atmospheric conditions (kV). Using (1)-(5), the required CFO_A can be computed using an iterative process.

Once the CFO_A is known, deterministic methods can be used to determine the required clearance distance. If we let the maximum switching overvoltage be equal to the withstand voltage of the air gap (CFO_A - 3σ) then the CFO_A can be written as (6).

$$CFO_A = \frac{V_m}{1 - 3\left(\frac{\sigma}{CFO_A}\right)} \tag{6}$$

where

V_m is equal to the maximum switching overvoltage, i.e. the value that has a 0.135% chance of being exceeded,

σ is the standard deviation of the air gap insulation,

CFO_A is the critical flashover voltage of the air gap insulation under non-standard atmospheric conditions.

The ratio of σ to the CFO_A given in (6) can be assumed to be 0.05 (5%) [1]. Thus, (6) can be written as (7).

$$CFO_A = \frac{V_m}{0.85} \tag{7}$$

Substituting (7) into (1) we arrive at (8).

$$V_m = 0.85 \cdot k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1 + \frac{8}{D}} \tag{8}$$

Equation 8 relates the maximum transient overvoltage, V_m, to the air gap distance, *D*. Using (8) to compute the required clearance distance for the specified air gap geometry (conductor to large structure) results in a probability of flashover in the range of 10^{-6}.

Transient Overvoltage

In general, the worst case transient overvoltages occurring on a transmission line are caused by energizing or re-energizing the line with the latter being the extreme case if trapped charge is 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 sparkover from the line conductor to nearby vegetation. Thus, the worst case scenarios that are typically analyzed for insulation coordination purposes (e.g. line energization and re-energization) can be ignored. For the purposes of FAC-003-2, the worst case transient overvoltage then becomes the maximum value that can occur with the line energized. Determining a realistic value of transient overvoltage for this situation is difficult because the maximum transient overvoltage factors listed in the literature are based on a switching operation of the line in question. In other words, these maximum overvoltage values (e.g. the values listed in [2], [3] and [5]) are based on the assumption that the subject line is being energized, re-energized or de-energized. These operations, by their very nature, will create the largest transient overvoltages. Typical values of transient overvoltages of in-service lines, as such, are not readily available in the literature because the resulting level of overvoltage is negligible compared with the maximum (e.g. re-energizing a transmission line with trapped charge). A conservative value for the maximum transient overvoltage that can occur anywhere along the length of an in-service ac line is approximately 2.0 p.u.[2]. This value is a conservative estimate of the transient overvoltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without a pre-insertion device (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. 362 kV), the maximum transient overvoltage 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 p.u. or less [2]. It is well known that these theoretical transient overvoltages will not be experienced at locations remote from the bus at which they were created; however, in order to be conservative, it will be assumed that all nearby ac lines are subjected to this same level of overvoltage. Thus, a maximum transient overvoltage factor of 2.0 p.u. for 302 kV and below and 1.4 p.u. for ac transmission lines 362 kV and above is used to compute the required clearance distances for vegetation management purposes.

The overvoltage characteristics of dc transmission lines vary somewhat from their ac counterparts. The referenced empirically derived transient overvoltage factor used to calculate the minimum clearance distances from dc transmission lines to vegetation for the purpose of FAC-003-2 will be 1.8 p.u.[3].

Example Calculation

An example calculation is presented below using the proposed method of computing the vegetation clearance distances. It is assumed that the line in question has a maximum operating voltage of 550 kV_{rms} line-to-line. Using a per unit transient overvoltage factor of 1.4, the result is a peak transient voltage of 629 kV_{crest}. It is further assumed that the line in question operates at a maximum altitude of 7000 feet (2.134 km) above sea level.

The required withstand voltage of the air gap must be equal to or greater than 629 kV_{crest}. Since the altitude is above sea level, (1) - (5) have to be iterated on to achieve the desired result. Equation (9) can be used as an initial guess for the clearance distance.

$$D_i = \frac{8}{\frac{3400 \cdot k_w \cdot k_g}{\left(\frac{V_m}{0.85}\right)} - 1} \tag{9}$$

For our case here, V_m is equal to 629 kV, k_w = 1.037 and k_g = 1.3. Thus,

$$D_i = \frac{8}{\frac{3400 \cdot k_w \cdot k_g}{\left(\frac{V_m}{0.85}\right)} - 1} = \frac{8}{\frac{3400 \cdot 1.037 \cdot 1.3}{\left(\frac{629}{0.85}\right)} - 1} = 1.535m \tag{10}$$

Using (2)-(5) and (8) the withstand voltage of the air gap is next computed. This value will then be compared to the maximum transient overvoltage.

$$CFO_S = k_w \cdot k_g \cdot \frac{3400}{1 + \frac{8}{D}} = 1.037 \cdot 1.3 \cdot \frac{3400}{1 + \frac{8}{1.535}} = 737.7kV \tag{11}$$

$$\delta = e^{-\frac{A}{8.6}} = e^{-\frac{2.134}{8.6}} = 0.78 \tag{12}$$

$$G_O = \frac{CFO_S}{500 \cdot D} = \frac{737.7}{(500) \cdot (1.535)} = 0.961 \tag{13}$$

$$m = 1.25 \cdot G_O (G_O - 0.2) = 1.25 \cdot 0.961(0.961 - 0.2) = 0.915 \tag{14}$$

$$V_m = 0.85 \cdot k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1 + \frac{8}{D}} = (0.85)(1.037)(1.3)(0.78)^{0.915} \left(\frac{3400}{1 + \frac{8}{1.535}} \right) = 499.8kV \tag{15}$$

The calculated V_m is less than 629 kV; thus, the clearance distance must be increased. A few iterations using (2)-(5) and (8) are required until the computed $V_m \geq$ 629 kV. For this case it was found that D = 1.978 m (6.49 feet) yielded V_m = 629.3 kV. Using this clearance distance the following values were computed for the final iteration.

$$CFO_S = k_w \cdot k_g \cdot \frac{3400}{1+\frac{8}{D}} = 1.037 \cdot 1.3 \cdot \frac{3400}{1+\frac{8}{1.978}} = 908.5kV \tag{16}$$

$$\delta = e^{-\frac{A}{8.6}} = e^{-\frac{2.134}{8.6}} = 0.78 \tag{17}$$

$$G_O = \frac{CFO_S}{500 \cdot D} = \frac{908.5}{(500)\cdot(1.978)} = 0.919 \tag{18}$$

$$m = 1.25 \cdot G_O(G_O - 0.2) = 1.25 \cdot 0.919(0.919 - 0.2) = 0.825 \tag{19}$$

$$V_m = 0.85 \cdot k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} = (0.85)(1.037)(1.3)(0.78)^{0.825}\left(\frac{3400}{1+\frac{8}{1.978}}\right) = 629.3kV \tag{20}$$

Therefore, the minimum vegetation clearance distance for a maximum line to line ac operating voltage of 550 kV at 7000 feet above sea level is 1.978 m (6.49 feet). Table 1 provides calculated distances for various altitudes and maximum system operating ac voltages.

Table 1 — Minimum Vegetation Clearance Distances (MVCD)[7]

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)	(AC) Maximum System Voltage (kV)[8]	MVCD (feet) Over sea level up to 500 ft	MVCD (feet) Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft
765	800	8.2ft	8.33ft	8.61ft	8.89ft	9.17ft	9.45ft	9.73ft	10.01ft	10.29ft	10.57ft	10.85ft	11.13ft
500	550	5.15ft	5.25ft	5.45ft	5.66ft	5.86ft	6.07ft	6.28ft	6.49ft	6.7ft	6.92ft	7.13ft	7.35ft
345	362	3.19ft	3.26ft	3.39ft	3.53ft	3.67ft	3.82ft	3.97ft	4.12ft	4.27ft	4.43ft	4.58ft	4.74ft
287	302	3.88ft	3.96ft	4.12ft	4.29ft	4.45ft	4.62ft	4.79ft	4.97ft	5.14ft	5.32ft	5.50ft	5.68ft
230	242	3.03ft	3.09ft	3.22ft	3.36ft	3.49ft	3.63ft	3.78ft	3.92ft	4.07ft	4.22ft	4.37ft	4.53ft
161*	169	2.05ft	2.09ft	2.19ft	2.28ft	2.38ft	2.48ft	2.58ft	2.69ft	2.8ft	2.91ft	3.03ft	3.14ft
138*	145	1.74ft	1.78ft	1.86ft	1.94ft	2.03ft	2.12ft	2.21ft	2.3ft	2.4ft	2.49ft	2.59ft	2.7ft
115*	121	1.44ft	1.47ft	1.54ft	1.61ft	1.68ft	1.75ft	1.83ft	1.91ft	1.99ft	2.07ft	2.16ft	2.25ft
88*	100	1.18ft	1.21ft	1.26ft	1.32ft	1.38ft	1.44ft	1.5ft	1.57ft	1.64ft	1.71ft	1.78ft	1.86ft
69*	72	0.84ft	0.86ft	0.90ft	0.94ft	0.99ft	1.03ft	1.08ft	1.13ft	1.18ft	1.23ft	1.28ft	1.34ft

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

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[7] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

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

Table 1 (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 152.4m	MVCD meters Over 152.4m up to 304.8m	MVCD meters Over 304.8m 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 1828.8m	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 1 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[7]

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

(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV) Over sea level up to 500 ft (Over sea level up to 152.4 m)	(DC) Nominal Pole to Ground Voltage (kV) Over 500 ft up to 1000 ft (Over 152.4 m up to 304.8 m	(DC) Nominal Pole to Ground Voltage (kV) Over 1000 ft up to 2000 ft (Over 304.8 m up to 609.6m)	(DC) Nominal Pole to Ground Voltage (kV) Over 2000 ft up to 3000 ft (Over 609.6m up to 914.4m	(DC) Nominal Pole to Ground Voltage (kV) Over 3000 ft up to 4000 ft (Over 914.4m up to 1219.2m	(DC) Nominal Pole to Ground Voltage (kV) Over 4000 ft up to 5000 ft (Over 1219.2m up to 1524m	(DC) Nominal Pole to Ground Voltage (kV) Over 5000 ft up to 6000 ft (Over 1524 m up to 1828.8 m)	(DC) Nominal Pole to Ground Voltage (kV) Over 6000 ft up to 7000 ft (Over 1828.8m up to 2133.6m)	(DC) Nominal Pole to Ground Voltage (kV) Over 7000 ft up to 8000 ft (Over 2133.6m up to 2438.4m)	(DC) Nominal Pole to Ground Voltage (kV) Over 8000 ft up to 9000 ft (Over 2438.4m up to 2743.2m)	(DC) Nominal Pole to Ground Voltage (kV) Over 9000 ft up to 10000 ft (Over 2743.2m up to 3048m)	(DC) Nominal Pole to Ground Voltage (kV) 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)

List of Acronyms and Abbreviations

ANSI	American National Standards Institute
IEEE	Institute of Electrical and Electronics Engineers
IVM	Integrated Vegetation Management
NERC	North American Electric Reliability Corporation

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