NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Transmission Vegetation Management
NERC Standard FAC-003-2 Technical Reference

Prepared by the

North American Electric Reliability Corporation

Vegetation Management Standard Drafting Team

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Introduction

This document is intended to provide supplemental information and guidance for complying with the requirements of Reliability Standard FAC-003-2. It is a supporting document and provides explanatory background to the requirements of the Standard.

The purpose of the Standard is to improve the reliability of the Bulk Electric System by preventing vegetation related outages that could lead to Cascading.

Compliance with the Standard is mandatory and enforceable.

Disclaimer

This supporting document may explain or facilitate implementation of reliability standard FAC-003-2 — Transmission Vegetation Management but does not contain mandatory requirements subject to compliance review.

Definition of Terms

Active Transmission Line Right of Way* — A strip of land that is occupied by active transmission facilities. This corridor does not include the inactive or unused part of the Right-of-Way intended for other facilities.

Examples of active and inactive portions of corridors include:

1) Where portions of the right of way are occupied by active facilities and other portions are acquired to accommodate future facilities. Power plant exits are examples where large rights-of-way are obtained for maximum corridor utilization and may currently have fewer structures constructed (see Figure 1 on page 6).
2) Rights of way where corridor edge zones are provided for vegetation to exist (see Figure 2 on page 7).
3) Where double-circuit structures are installed but only one circuit is currently strung with conductors (see Figure 3 on page 8).

Critical Clearance Zone* — The area mapped by the radial distance around a conductor specified in Table I of Attachment 1to the reliability standard FAC-003-2 — Transmission Vegetation Management Program when the conductor is energized and operating between no-load and its Rating, including the design blow-out, however the zone shall not extend beyond the limits of the Active Transmission Line Right of Way.

Sustained Outage** — The deenergized condition of a transmission line resulting from a fault or disturbance following an unsuccessful automatic reclosing sequence and/or unsuccessful manual reclosing procedure.

Cascading ** — The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.

Rating ** — The operational limits of a transmission system element under a set of specified conditions.

*To be added to the NERC glossary of terms with final approval of this standard revision
** Currently defined in the NERC glossary of terms

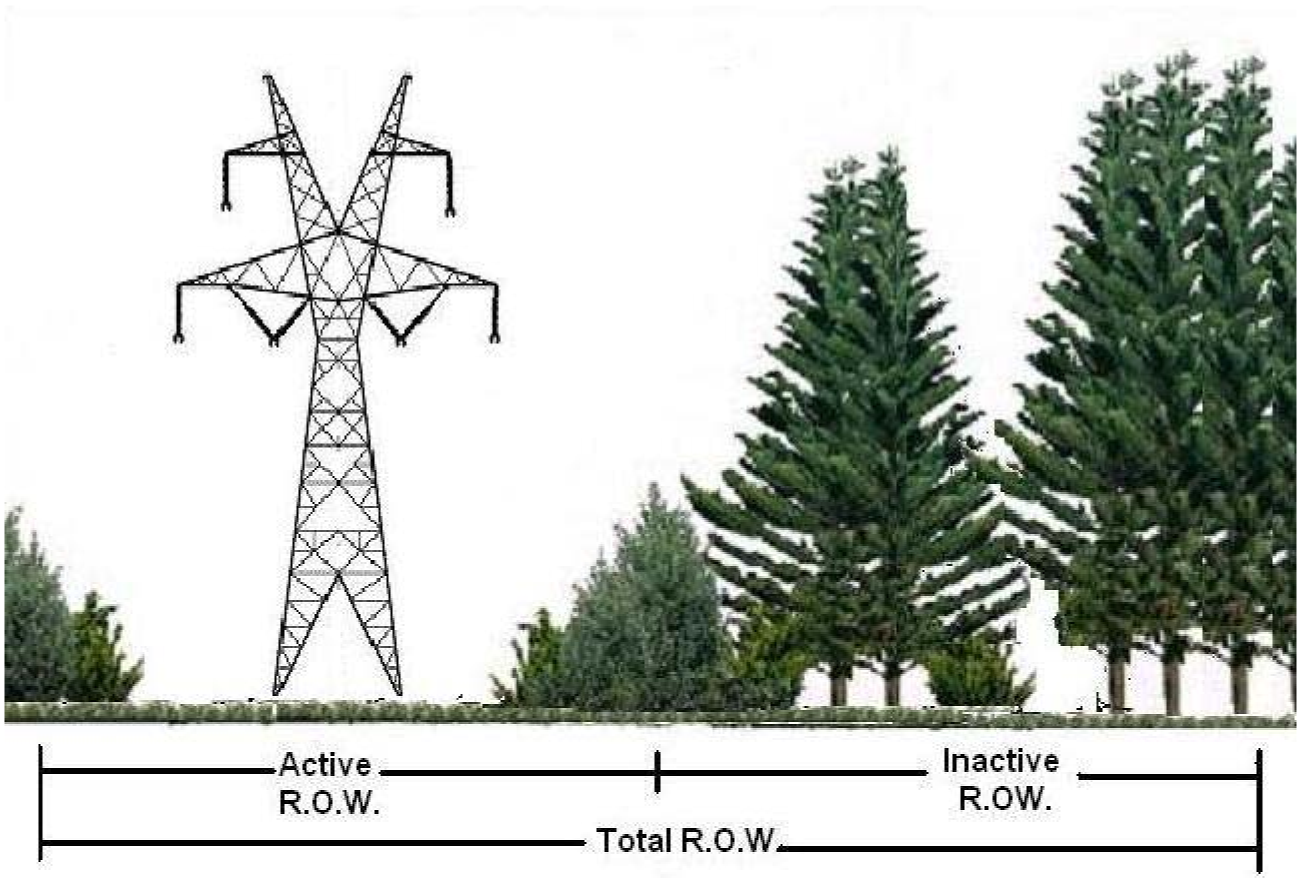

Figure 1

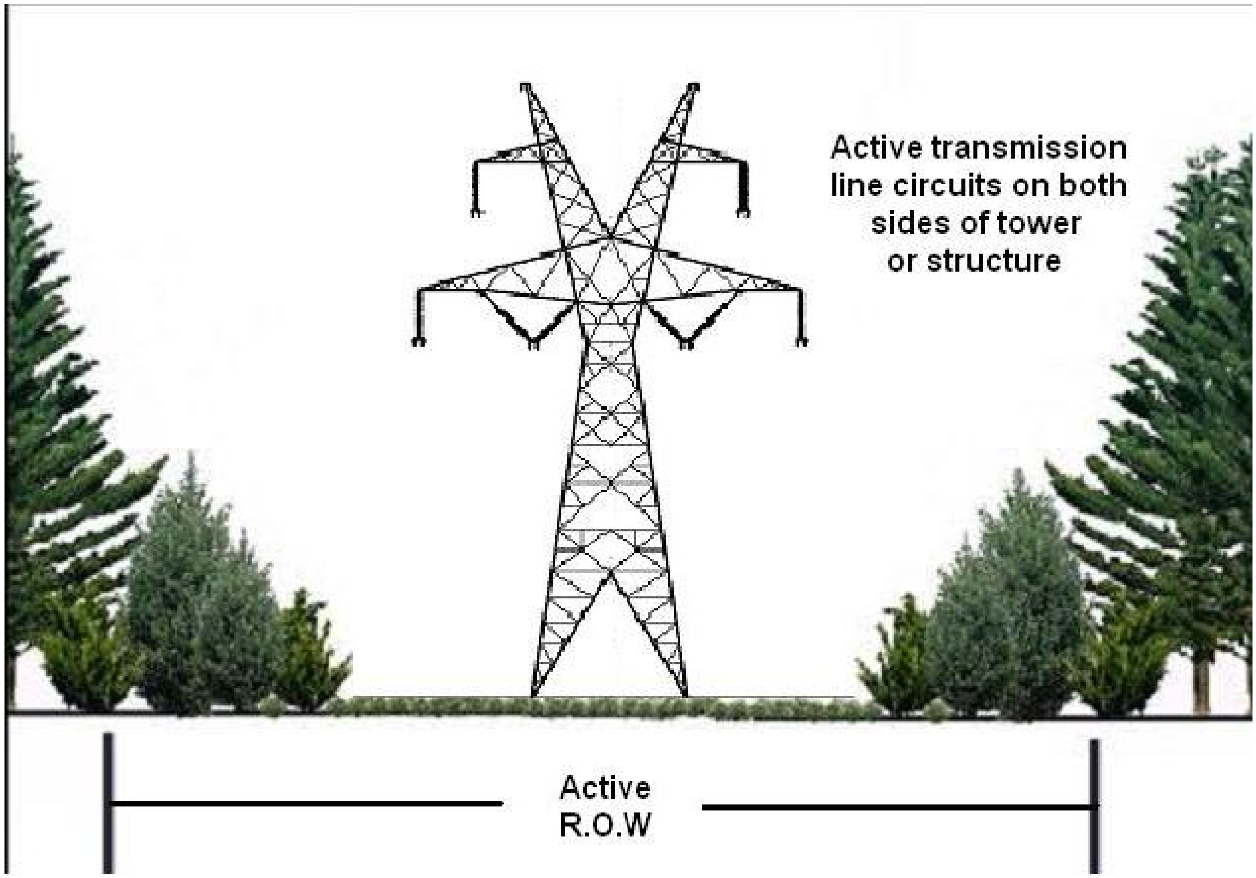
Active transmission
line circuits on both
sides of tower
or structure
Active
R.O.W

Figure 2

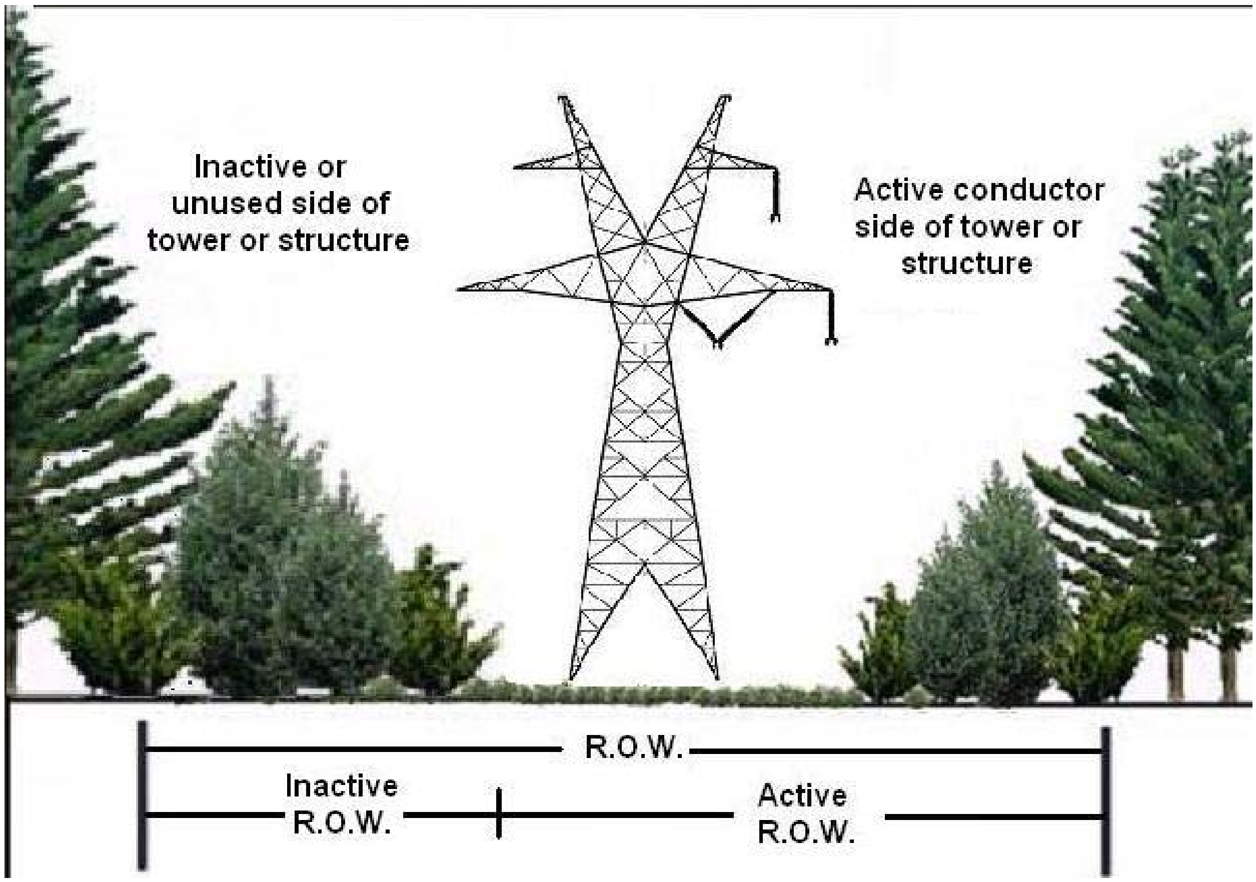
Inactive or
unused side of
tower or structure
Active conductor
side of tower or
structure
R.O.W.
Inactive
R.O.W.
Active
R.O.W.

Figure 3

Applicability of the Standard

4. *Applicability:*

   4.1. Functional Entities:

   4.1.1. Transmission Owner

   4.1.2. Reliability Coordinator

   4.2. Facilities:

   4.2.1. Transmission lines ("applicable lines") operated at 200kV or higher, and transmission lines operated below 200kV designated by the Reliability Coordinator as being subject to this standard including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities.

   4.2.2. Transmission lines operated below 200kV as designated by the Reliability Coordinator as being subject to this standard become subject to this standard 12 months after the date the Reliability Coordinator initially designates the Transmission Line as being subject to this standard.

   4.2.3. Existing transmission line(s) operated at 200kV or higher that are newly acquired by a Transmission Owner and were not previously subject to this standard, become subject to this standard 12 months after the acquisition date of the transmission line(s).

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.

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 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

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

voltages. For example, localized customer service could be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. 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 poses an increased outage risk when numerous transmission lines are operating at or near their Rating as a result of increased sags incurred. This poses a significant risk of multiple line failures and Cascading. On the other hand, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are statistically intermittent. The probability of occurrence of these events is not dependent on heavy loads. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these type events are highly unlikely to cause large-scale grid failures.

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 vegetation management standard 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 (at one major U.S. utility, only 3% of its thousands of sub-200kV circuits are considered critical), 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 selected, after evaluating several alternatives, the Reliability Coordinator as the best entity to determine applicable lines below 200 kV that are subject to this standard.

Transmission Vegetation Management Program

R1. *Each Transmission Owner shall have a documented transmission vegetation management program designed to control vegetation on its Active Transmission Lines' Rights of Way. The transmission vegetation management program shall:*

The purpose of the Standard is to prevent vegetation-related outages that can result in Cascading. Under Requirement R1, each Transmission Owner is required to have a transmission vegetation management program designed to control vegetation on the Active Transmission Line Right of Way. The transmission vegetation management program is an important component of the Standard because it is the formal document that Transmission Owners use to manage vegetation to achieve the purpose of the Standard. An adequate transmission vegetation management program formally establishes the guidelines that are used by the Transmission Owner to plan and perform vegetation work that is necessary to prevent transmission outages and minimize risk to the transmission system.

It should be noted that Requirement R1 is concerned with the content of the transmission vegetation management program and supporting documents, but does not address implementation of the elements of the transmission vegetation management program. Other requirements address implementation of the transmission vegetation management program. For example, sub-part 1.4 requires Transmission Owners to establish an imminent threat procedure. However, sub-part 1.4 does not address implementation or execution of the imminent threat procedure. This is addressed in Requirement R2. These situations will be reviewed in the following discussion.

Methodology to Control Vegetation

R1.1. *Specify the methodologies that the Transmission Owner uses to control vegetation*[2]

Transmission Owners are required to specify the methodologies or management methods used to control vegetation on applicable lines in the transmission vegetation management program. The methods specified in the transmission vegetation management program under this requirement are the methods that will be applied to the development and implementation of the annual work plan (R1.3 and R8).

The intent of this sub-part is for the Transmission Owner to list and generally describe the vegetation management methods that are used on its Active Transmission Line Right of Way. Transmission Owners are not required to deploy each of the methods listed in every situation. Nor are they required to provide a detailed description of each method, although these may exist in the Transmission Owner's specifications. Instead, the methods listed under this requirement are intended to provide a menu of vegetation management options that the Transmission Owner may deploy when developing and implementing the annual work plan based upon the many different circumstances that are typically encountered.

It should be emphasized that pruning is an ineffective maintenance method. Removal is always superior to pruning in ensuring tree conflicts do not occur.

In general, the best management practice for the Transmission Owner is to always exercise its maximum legal rights to achieve the objectives of the transmission vegetation management program. This minimizes the possibility of conflicts between energized conductors and vegetation. Since this is not always possible, the Transmission Owner's strategy should be to use its prescribed vegetation maintenance methods to work towards or achieve the maximum use of the Active Transmission Line Right of Way.

The following are several examples of how methodologies could be specified in the transmission vegetation management program under this requirement. These are offered as examples only and it is recognized that numerous other methodologies could be included in the transmission vegetation management program. It is also recognized that more detailed descriptions would typically be included in the Transmission Owner's internal specifications and procedures. The "average" tree does not usually cause a Sustained Outage. It is above-average growth that creates the greatest risk. In summary, methods must be applied in a sound biological manner

<u>Mechanical Clearing</u> — Remove all trees and brush in the Active Transmission Line Right of Way. Cut or mow all stumps to 3 inches or less above grade. De-limb and windrow on the edge of the right of way those larger trees that could be obstructive to other line maintenance activities.

<u>Selective Mechanical Tree Removal</u> — Selectively remove with chain saws or mechanized equipment all tall-growing species of trees, as listed in the specifications. Chemically treat the stumps of re-sprouting trees with the herbicide mixtures identified in the specification within one

[2] *ANSI A300, Tree Care Operations — Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.*

hour of making the cut. All low-growing species of shrubs and trees, as listed in the specification, will be preserved unless otherwise noted.

<u>Low-Volume Foliar Selective Herbicide Treatment</u> — Selectively treat with herbicide <u>all</u> tall-growing species of trees as listed in the specification which are less than ten feet in height, using the low-volume foliar herbicide mixture and application process listed in the specification. All low-growing species of shrubs and trees, as listed in the specification will be preserved unless otherwise noted.

<u>Side Pruning</u> — Prune trees adjacent to the Active Transmission Line Right of Way that have grown to an extent that they have encroached upon or will soon encroach upon the clearances listed in the specification. In cases where specified clearances can not be achieved due to Active Transmission Line Right of Way width restrictions, remove branches to prevent entry into the Active Transmission Line Right of Way.

ANSI A300 – Best Management Practices for Tree Care Operations

Transmission Owners have the option of adopting the procedures and practices contained in an industry-recognized ANSI Standard known as A300 for use as a central component of its vegetation management program. The following is a description of A300.

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's *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 the most appropriate techniques to apply to electric right-of-way projects in order to exceed those requirements.

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 outages caused by vegetation growing into electric facilities and minimizing them from trees growing outside the right of way, 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.

Evaluations can be comprehensive or point sample, and can be done to obtain information on an entire program or an individual project. Comprehensive evaluations account for vegetation that could potentially affect management objectives, including hazard trees. Program-level comprehensive evaluations can be made of all target vegetation on a system, while project-level evaluations focus on vegetation relevant to a specific job. Comprehensive evaluations provide the advantage of supplying a complete set of data upon which to base management decisions. On the other hand, comprehensive surveys can be impractical for utilities with large numbers of trees, limited human and financial resources, or both.

Point sampling offers an alternative for utilities for which comprehensive inventories are impractical. Point sampling is cost effective, and has a proven track record for reasonable accuracy. A common method involves dividing a management area (a system or project) into equal-sized units and selecting a random sample sufficient to statistically represent the total work quantity. Random selection eliminates the chance of bias on the part of the investigator. Every plant or plant community of interest within each selected area is inventoried, with collected data used to forecast the total workload.

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. If pruning is necessary, it should comply with ANSI A300 Part 1 (ANSI 2001) and ISA best management practices for utility pruning (Kempter 2004).

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 are essential for effective 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, work loads, growth rate of predominant vegetation, geography, accessibility, and in some cases, time lapsed since the last scheduled work.

Clearances Following Work

The Transmission Owner should establish and document appropriate minimum clearance distances to be achieved at the time of work. Clearances following work should be sufficient to meet management objectives, including reducing preventing trees from entering the Critical Clearance Zone, 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

Integrated vegetation management offers 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. Tree-resistant plant communities can be a desirable objective to reduce long-term work loads and costs because, once established, they out-compete incompatible plants. When effectively implemented, IVM is a systematic, preventive strategy that results in site-specific treatments to meet management objectives. A sound program includes documented processes to evaluate results, which should involve both monitoring for quality assurance while work is underway and after it is completed. However, 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 where appropriate.

Vegetation Inspection Frequency

R1.2. *Specify a vegetation inspection frequency of at least once per calendar year that takes into account local* [3] *and environmental factors.*

The transmission vegetation management program shall specify the frequency of inspection. The inspection frequency shall be at least once per calendar year. Transmission Owners should consider factors that could warrant more frequent inspection including growth studies, the need to insure individual fast-growing trees have not encroached into the Critical Clearance Zone, the need to identify excessive spring growth, and the need to identify seasonally occurring hazard trees.

[3] Local factors include treatment cycle, extent and type of treatment, and their relationship to the normal growth rate.

Annual Plans

R1.3. *Require an annual plan that identifies the applicable lines to be maintained and work to be performed during the year. It shall be flexible to adjust to changing conditions and to findings from vegetation inspections. Adjustments to the plan within the year are permissible. The plan shall take into consideration permitting and scheduling requirements from landowners or regulatory authorities. It shall support the objectives of the transmission vegetation management program and use the methodologies outlined in the transmission vegetation management program.*

The work plan is not intended to be a "span-by-span" detailed description of all work to be performed. It is intended to require the Transmission Owner to plan and schedule vegetation work to avoid encroachment into the Critical Clearance Zone.

The reference in the standard to "implement the annual work plan for vegetation management to accomplish the purpose of this standard within the extent of its easement and/or legal rights" is intended to address the importance of maintaining all locations on the Active Transmission Line Right of Way for reliability purposes in lieu of making special exceptions.

- Property owners and other interested parties occasionally request special considerations to leave undesirable vegetation conditions. It is recognized that such considerations must never be allowed to impact reliability.
- These undesirable vegetation conditions require more frequent work or inspections than other locations with similar vegetation threats and similar easement rights which are not subject to the special property requests
- The Transmission Owner's vegetation maintenance work necessary to implement the annual work plan is most effective when performed to the maximum extent allowed by any legal and/or easement rights.
- The Transmission Owner should, therefore, endeavor to maintain its Active Transmission Line Right of Way to the full extent of its legal rights at all times and in all cases.

This approach is superior to incremental management over 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 Active Transmission Line Right of Way .

Imminent Threat Procedure

> ***R1.4.*** *Require a process or procedure for response to imminent threats of a vegetation related Sustained Outage. The process or procedure shall specify actions which shall include immediate communication of the threat to the Transmission Operator, and may include actions such as a temporary reduction in line Rating, switching lines out of service, or other actions.*

The term "imminent threat" refers to a vegetation condition which is placing the transmission line at a significant risk of a Sustained Outage.

Examples of imminent threats may include vegetation that is rapidly approaching or has encroached within the Critical Clearance Zone or a tall tree which has been uprooted and is leaning precariously toward transmission conductors which could draw an arc when the tree falls. Both cases represent imminent threats due to the high probability that they could cause a Sustained Outage.

Two key elements of an acceptable imminent threat procedure are outlined below:

- Upon discovery of an imminent threat, the operating authority (operating authority refers to personnel with direct responsibility for operating the transmission lines, including but not limited to ordering the de-rating or de-energization of transmission lines) will be notified of the condition so that action (such as temporary reduction in line Rating, switching the line out of service, etc.) may be taken until the threat is relieved.
- The protocol for contacting the operating authority should be defined. For example, some Transmission Owners' processes may require a call directly to the operating authority, while other Transmission Owners may require a call to a supervisor or field forester. The process should be explicit for the expectations of actions upon the individual discovering the imminent threat.

The urgency of addressing imminent threats may be contrasted with the longer time frames of corrective action plans which are developed from a corrective action process as defined in R1.5. The communication of imminent threats should typically be done in a matter of minutes or hours, whereas corrective action plans may require months or years (see requirement R1.5).

All serious conditions are not necessarily considered as imminent threats under the Standard. For example, Transmission Owners may assign a high priority to the removal of trees that have been designated for removal under a danger tree identification program, but not yet encroached within the Critical Clearance Zone. These trees are not considered imminent threats under the Standard because there is not a high probability that they will grow sufficiently before treatment to encroach into the Critical Clearance Zone or immediately fall and subsequently cause a Sustained Outage.

Some encroachments may be found within the Critical Clearance Zone at a time when there exists sufficient safety clearance distance from the conductors to allow their safe removal. If so their removal may not require switching the line out of service, de-rating the line temporarily or other actions.

Interim Corrective Action Process

R1.5. *Specify an interim corrective action process for use when the Transmission Owner is constrained from performing vegetation maintenance as planned.*

Each Transmission Owner is required to specify an interim corrective action process in its transmission vegetation management program. The purpose of this sub-part is to ensure that Transmission Owners have in place a process to develop a corrective action plan that identifies and mitigates risk to the reliability of transmission lines when the Transmission Owner is constrained from performing vegetation maintenance work as planned.

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. The Standard recognizes that numerous circumstances resulting in work constraints can occur, and that numerous ways to identify and mitigate the associated risks to line reliability can be developed. Thus, the requirement is such that the Transmission Owner must specify a general, flexible corrective action process which provides a framework that can be applied over a wide range of situations to ensure line reliability.

A general interim corrective action process may include the following steps:

- Determine and understand the constraint
- Determine the degree of risk to line reliability due to the constraint
- Determine a specific interim corrective action plan to mitigate the risk
- If applicable, determine the time frame for the corrective action plan to be in effect

Implement Imminent Threat Procedure

R2. *Each Transmission Owner shall implement its imminent threat procedure when the Transmission Owner has knowledge, obtained through normal operating practices or notification from others, that the Critical Clearance Zone is approached by vegetation to prevent an encroachment of the Critical Clearance Zone.*

Determining Clearance Distances for Vegetation near Transmission Lines

A vital component of an effective vegetation management program is maintaining an adequate distance between energized transmission line conductors and vegetation. Maintaining a minimum separation can prevent inadvertent Sustained Outages caused by direct contact of the conductors and the vegetation or sparkover between the conductors and the vegetation.

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, sparkover 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 242 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.

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

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

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

$$m = 1.25 \cdot G_O (G_O - 0.2) = 1.25 \cdot 0.919 (0.919 - 0.2) = 0.825 \quad (19)$$

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

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 I provides calculated distances for various altitudes and maximum system operating ac voltages.

TABLE I — Minimum Vegetation Clearance Distances
For Alternating Current Voltages

(AC) Nominal System Voltage (kV)	**(AC) Maximum System Voltage (kV)**	**D feet (meters) sea level**	**D feet (meters) 3,000ft (914.4m)**	**D feet (meters) 4,000ft (1219.2m)**	**D feet (meters) 5,000ft (1524m)**	**D feet (meters) 6,000ft (1828.8m)**
765	800	8.06ft (2.46m)	8.89ft (2.71m)	9.17ft (2.80m)	9.45ft (2.88m)	9.73ft (2.97m)
500	550	5.06ft (1.54m)	5.66ft (1.73m)	5.86ft (1.79m)	6.07ft (1.85m)	6.28ft (1.91m)
345	362	3.12ft (0.95m)	3.53ft (1.08m)	3.67ft (1.12m)	3.82ft (1.16m)	3.97ft (1.21m)
230	242	2.97ft (0.91m)	3.36ft (1.02m)	3.49ft (1.06m)	3.63ft (1.11m)	3.78ft (1.15m)
161*	169	2ft (0.61m)	2.28ft (0.69m)	2.38ft (0.73m)	2.48ft (0.76m)	2.58ft (0.79m)
138*	145	1.7ft (0.52m)	1.94ft (0.59m)	2.03ft (0.62m)	2.12ft (0.65m)	2.21ft (0.67m)
115*	121	1.41ft (0.43m)	1.61ft (0.49m)	1.68ft (0.51m)	1.75ft (0.53m)	1.83ft (0.56m)
88*	100	1.15ft (0.35m)	1.32ft (0.40m)	1.38ft (0.42m)	1.44ft (0.44m)	1.5ft (0.46m)
69*	72	0.82ft (0.25m)	0.94ft (0.29m)	0.99ft (0.30m)	1.03ft (0.31m)	1.08ft (0.33m)

*As designated by the Reliability Coordinator

TABLE I — Minimum Vegetation Clearance Distances (D)
For Alternating Current Voltages

(AC) Nominal System Voltage (kV)	(AC) Maximum System Voltage (kV)	D feet (meters) 7,000ft (2133.6m)	D feet (meters) 8,000ft (2438.4m)	D feet (meters) 9,000ft (2743.2m)	D feet (meters) 10,000ft (3048m)	D feet (meters) 11,000ft (3352.8m)
765	800	10.01ft (3.05m)	10.29ft (3.14m)	10.57ft (3.22m)	10.85ft (3.31m)	11.13ft (3.39m)
500	550	6.49ft (1.98m)	6.7ft (2.04m)	6.92ft (2.11m)	7.13ft (2.17m)	7.35ft (2.24m)
345	362	4.12ft (1.26m)	4.27ft (1.30m)	4.43ft (1.35m)	4.58ft (1.40m)	4.74ft (1.44m)
230	242	3.92ft (1.19m)	4.07ft (1.24m)	4.22ft (1.29m)	4.37ft (1.33m)	4.53ft (1.38m)
161*	169	2.69ft (0.82m)	2.8ft (0.85m)	2.91ft (0.89m)	3.03ft (0.92m)	3.14ft (0.96m)
138*	145	2.3ft (0.70m)	2.4ft (0.73m)	2.49ft (0.76m)	2.59ft (0.79m)	2.7ft (0.82m)
115*	121	1.91ft (0.58m)	1.99ft (0.61m)	2.07ft (0.63m)	2.16ft (0.66m)	2.25ft (0.69m)
88*	100	1.57ft (0.48m)	1.64ft (0.50m)	1.71ft (0.52m)	1.78ft (0.54m)	1.86ft (0.57m)
69*	72	1.13ft (0.34m)	1.18ft (0.36m)	1.23ft (0.37m)	1.28ft (0.39m)	1.34ft (0.41m)

*As designated by the Reliability Coordinator

Likewise, a minimum clearance distance table for high voltage direct current lines may be derived using alternating current methods [7]. Table I is expanded below to provide calculated distances for various altitudes and system operating voltages.

TABLE I — Minimum Vegetation Clearance Distances (D)
For Direct Current Voltages

(DC) Pole to Pole Nominal Voltage (kV)	**D feet (meters) sea level**	**D feet (meters) 3,000ft (914.4m) Alt.**	**D feet (meters) 4,000ft (1219.2m) Alt.**	**D feet (meters) 5,000ft (1524m) Alt.**	**D feet (meters) 6,000ft (1828.8m) Alt.**
1500	13.92ft (4.24m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)
1200	10.07ft (3.07m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)
1000	7.89ft (2.40m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)
800	4.78ft (1.46m)	5.35ft (1.63m)	5.55ft (1.69m)	5.75ft (1.75m)	5.95ft (1.81m)
500	3.43ft (1.05m)	4.02ft (1.23m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)

Pole to Pole Nominal Voltage (kV)	**D feet (meters) 7,000ft (2133.6m) Alt.**	**D feet (meters) (8,000ft (2438.4m) Alt.**	**D feet (meters) 9,000ft (2743.2m) Alt.**	**D feet (meters) 10,000ft (3048m) Alt.**	**D feet (meters) 11,000ft (3352.8m) Alt.**
1500	16.55ft (5.04m)	16.9ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
1200	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	(13.54ft 4.13m)
1000	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
800	6.15ft (1.87m)	6.36ft (1.94m)	6.57ft (2.00m)	6.77ft (2.06m)	6.98ft (2.13m)
500	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5ft (1.52m)	5.17ft (1.58m)

Critical Clearance Zone

The best management practice for the Transmission Owner is to always exercise its maximum legal rights with regards to Active Transmission Line Right of Way vegetation clearing work. Doing so minimizes the possibility of incurring any conflicts between energized conductors and vegetation. Since this is not always possible, Table I in FAC-003-2 identifies the minimum radial distances, derived using the Gallet equations, which are required to prevent a flashover (sparkover) at the corresponding line voltage ratings.

The minimum radial distance values in Table I represent a radial zone (or shell) around a conductor within which there is a high probability that a flashover event will occur. However, the minimum radial distance concept should not be mistaken to suggest that a static condition is being managed; in fact, the reality is a very dynamic situation. The use of the Critical Clearance Zone concept as set forth by the Standard attempts to simplify and address this complex dynamic management requirement to aid in field applications.

The conductor's position in space at any point in time is continuously changing as a reaction to a number of different loading variables affecting the conductor's movement within each line span. 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 swing 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 continuously moving. Over some period of time, the conductor will ultimately pass through all possible positions it can occupy in space. This full range of positions can be thought of as the conductor's "flight path".

As the conductor moves throughout its flight path, the minimum clearance shell surrounding the conductor obviously moves with it. Therefore, this shell also maps out an area in space called the "Critical Clearance Zone". Any conductive item (such as a tree) that has encroached within this Critical Clearance Zone has the potential to cause flashover when the conductor enters a corresponding location in its flight path.

The shape and size of the Critical Clearance Zone around the conductor is irregular and will change depending on where a conductor segment is located within the span. At mid-span, where the potential for conductor movement is the greatest due to sag and wind deflection, the corresponding Critical Clearance Zone is also the largest and most irregular. Conversely, the Critical Clearance Zone is at its smallest near the conductor attachment to the transmission line structure insulator assembly. In the most extreme case, the Critical Clearance Zone again becomes a simple radial circle at a rigidly fixed insulator attachment point such as with a V-string or standoff insulator type of installation. Figures 4 through 7 below demonstrate these concepts.

With the size, shape and area of the Critical Clearance Zone dramatically changing as one progresses along a span, identifying the precise location and boundary of the Critical Clearance Zone around the conductor in the field becomes very problematic. First, all the variables involved make it very complicated and difficult to calculate the exact shape and size of the Critical Clearance Zone at any particular location in any one, and ultimately all, of the many spans of a transmission line. Second, at the time of field measurement, it is very difficult to precisely know where the conductor is within its wide range of all possible flight path positions.

Therefore, even if the exact size and shape of the Critical Clearance Zone is known, it becomes nearly impossible to field correlate and accurately "superimpose" the Critical Clearance Zone around the conductor.

There are also operational adjustments that must be made to the Critical Clearance Zone as well when managing vegetation. When transmission lines are initially designed, basic engineering assumptions and calculations are made with regard to the maximum environmental and physical forces to which the facility will be exposed as well as anticipated electrical loads. Again, these assumptions include the consideration of things like the maximum wind and ice loading, thermal heating and dissipation, span lengths, conductor strength, associated stringing and sagging conditions, etc. All of these design considerations are combined to define the anticipated "design flight path" for the conductor within each span. However, transmission facilities are not always available to be operated at their full Rating for numerous reasons. For example, transmission facilities can sometimes be built to a higher design voltage than they are currently operated at to reserve capacity that will be utilized with other future system upgrades. Consequently in cases such as these that do not subject a facility to its maximum design capacity, the "operational flight path" of the conductor can be anticipated to be somewhat smaller than the full range of the "designed flight path". Subsequent decisions regarding vegetation management, therefore, need only be made with regard to ensuring the integrity of the actual anticipated operational flight path for the conductor.

Given all of the complicated considerations outlined above, vegetation management around near the Critical Clearance Zone can be very challenging. It is important that the full conductor flight path, within the appropriate limits defined by the lesser of the design parameters or the operational constraints for the line, be available at all times to accommodate the full range of power system operational requirements. Even with the best planning and execution of the vegetation management program, including the use of frequent inspections, vegetation can still unintentionally approach or even encroach into the Critical Clearance Zone without a Transmission Owner's immediate awareness. Such an event does not always result in a flashover if the conductor is not simultaneously occupying that same area of the Critical Clearance Zone. An example of this would be when the conductor is not currently being blown to the extreme edge of its designed flight path from a maximum anticipated wind loading event. However, in such a case it is imperative - and required by the Standard - that the Transmission Owner's Imminent Threat process be implemented immediately upon discovery to correct the approaching or encroaching situation. Failure to do so is a violation of Requirement R2 of the standard.

An accurate representation of the Critical Clearance Zone in the field, correctly positioned around the conductor, is critically important if the Critical Clearance Zone is to be used as an essential parameter for vegetation management and Standards regulation. Because of all of the variables and difficulties in determining the Critical Clearance Zone, as well as the consequences associated with Requirement R4 for failure to maintain Critical Clearance Zone clearances, it is anticipated and expected that Transmission Owners will manage vegetation at distances greater than the Critical Clearance Zone. Given the variation of the Critical Clearance Zone's size and shape at various locations along the line span, it is anticipated that many Transmission Owners will establish a work trigger well outside the Critical Clearance Zone.

Further, to ensure adequate field monitoring and detection of incompatible vegetation conditions, Standard FAC 003-2 requires inspections on a frequency that is appropriate to verify and ensure there are no undiscovered Critical Clearance Zone approaches or encroachments. The anticipated growth rates of the vegetation surveyed in relationship to its speed of approach and distance from the Critical Clearance Zone is a very important consideration during inspection. At a minimum, the inspection frequency can not be less than once per year.

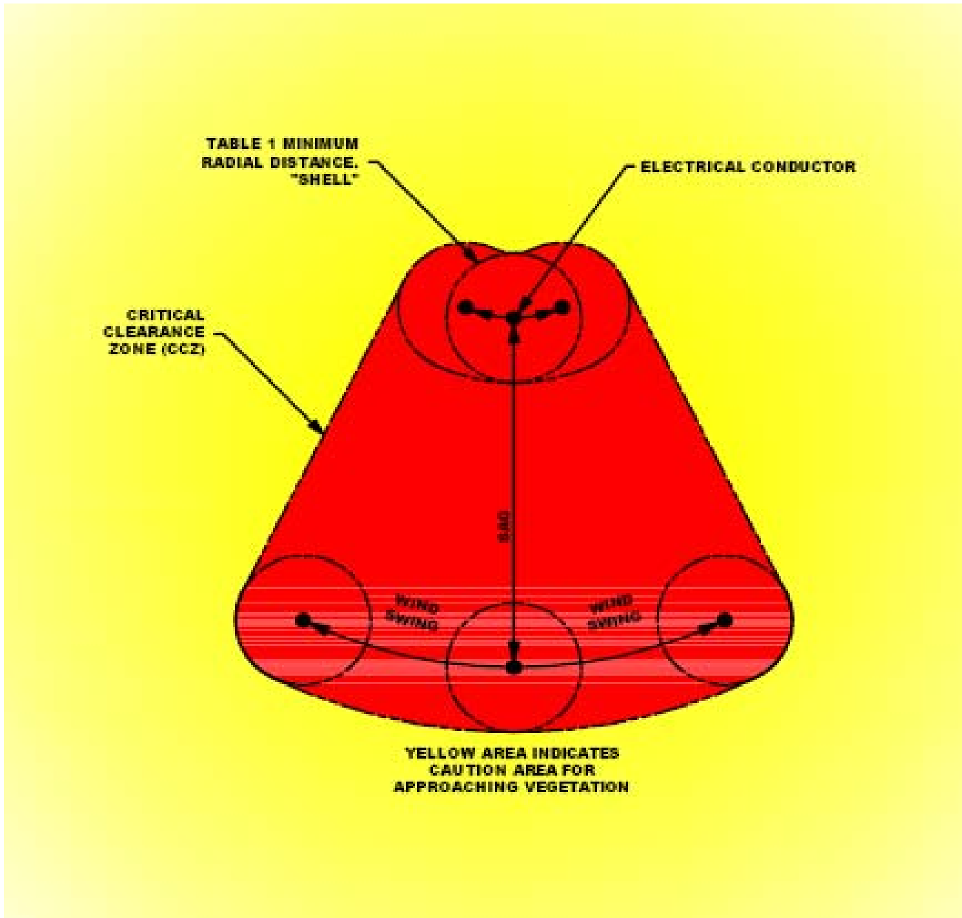

Figure 4

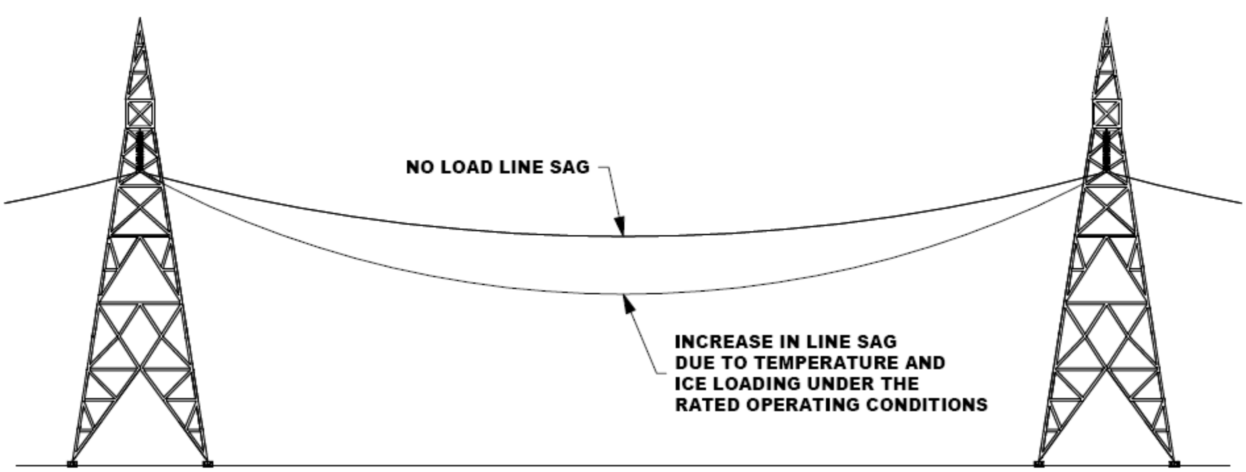

Figure 5

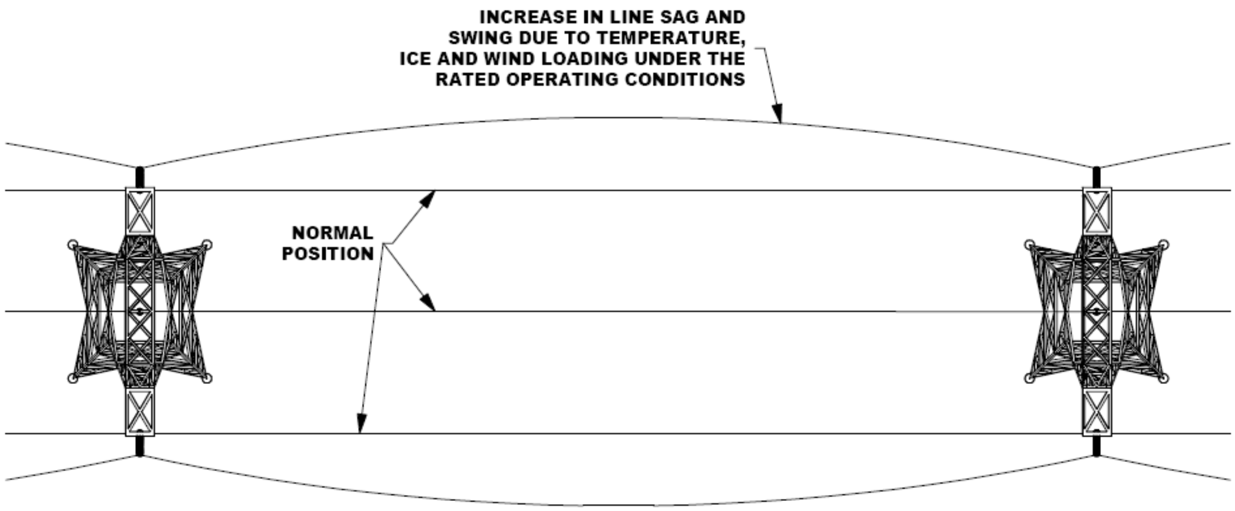

Figure 6

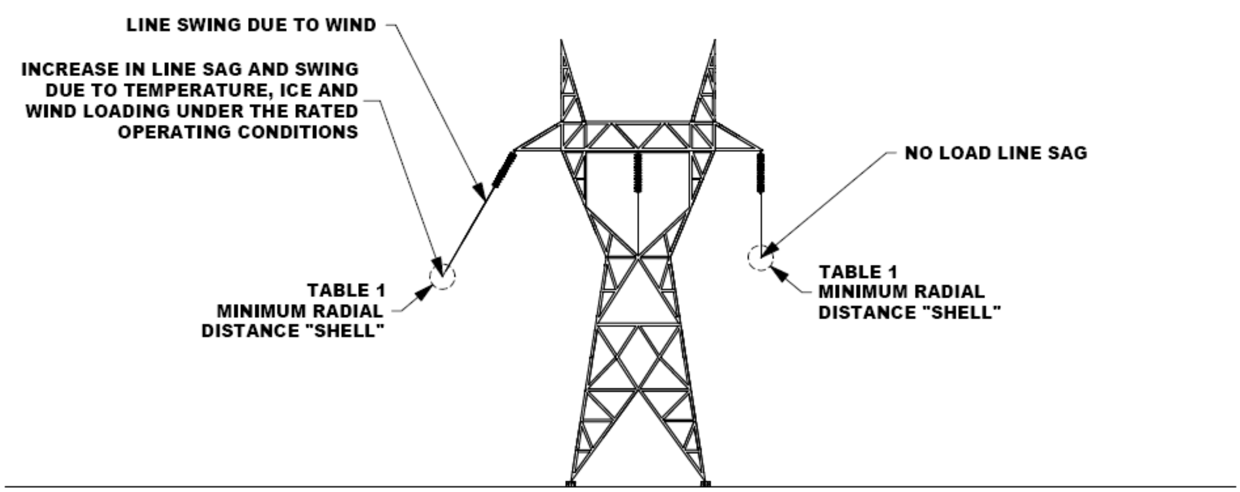

Figure 7

Conduct Vegetation Inspections

_R3._ *Each Transmission Owner shall conduct inspections of all applicable lines in accordance with the frequency specified in its transmission vegetation management program.*

The Requirement is self explanatory and no additional information is necessary.

Encroachments within Critical Clearance Zone

R4. *Each Transmission Owner shall prevent encroachments within the Critical Clearance Zone of its applicable transmission lines with the following exceptions:*
1. Encroachments of the Critical Clearance Zone that result from natural disasters[4]
2. Encroachments of the Critical Clearance Zone that result from human or animal activity[5]

The presence of vegetation in the Critical Clearance Zone presents a state of reduced transmission system reliability and is a violation of Requirement R4. A Critical Clearance Zone encroachment incident is defined as the presence in the Critical Clearance Zone of vegetation from a single tree, or a group of trees or vegetation in a single span or adjacent spans. The exposure to Critical Clearance Zone encroachment incidents varies widely among transmission systems owned by large and small Transmission Owners.

[4] Examples include, but are not limited to, 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.

[5] Examples include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation.

Sustained Outages— Vegetation Growth

R5. *Each Transmission Owner shall prevent Sustained Outages of applicable lines*[6] *due to vegetation growing into a conductor operating between no load and its Rating with the following exceptions:*

1. *Sustained Outages of applicable lines that result from natural disasters.*
2. *Sustained Outages of applicable lines that result from human or animal activity.*

The most significant vegetation related reliability risk to the transmission system involves Sustained Outages due to vegetation growing into transmission lines. This is commonly referred to as a grow-in or sag-in. These events could lead to widespread cascading failures, such as the August 10, 1996 West Coast Blackout and the August 14, 2003 US-Canada blackout.

These blackouts occurred during the summer months when the transmission system is more vulnerable to cascading events which can lead to blackouts. A review of NERC disturbance reports related to blackouts indicates that most major blackouts attributed to vegetation were caused by grow-in or sag-in events during the summer.

Since grow-in events have historically resulted in several major blackouts the standard recognizes that they present a high risk to the system. Sustained Outages due to sag-ins that occur due to natural disasters are beyond the control of the Transmission Owner. In addition it is often not possible in the aftermath of a natural disaster to do the forensics to determine what happened. Therefore such outages are not considered violations of this requirement.

Sustained Outages due to sag-ins that occur due to human (such as new plantings of tall vegetation, automobile collisions into towers) or animal activity are beyond the control of the Transmission Owner. Therefore such Sustained Outages are not considered violations of this requirement.

The standard recognizes that multiple Sustained Outages on an individual line can be caused by the same vegetation. As such, the Standard recognizes these events as a single Sustained Outage. For example a Sustained Outage could be caused by a tree but be mistakenly attributed to something else (e.g. contaminated insulator string or a different tree). After that situation is addressed the line would be re-energized and would suffer another Sustained Outage from contact with the tree.

Investigations are often hampered by weather conditions, darkness and/or other factors that lead to a misdiagnosis of the cause of the fault as noted in the above example.

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

Sustained Outages— Blowing Vegetation

R6. *Each Transmission Owner shall prevent Sustained Outages of applicable lines[6] due to the blowing together of vegetation and a conductor with Active Transmission Line Right of Way (operating within design blow-out conditions) with the following exception:*

1. *Sustained Outages of applicable lines that result from sustained winds or gusts due to natural [4]*

4

Unlike grow-ins which are addressed in Requirement R5, a review of NERC disturbance reports related to blackouts indicates major blackouts were rarely if ever attributed to vegetation-related Sustained Outages due to blowing together of vegetation and transmission conductors. These events are known as blow-ins.

The standard recognizes that multiple Sustained Outages on an individual line can be caused by the same vegetation. As such, the Standard considers these multiple events caused by the same vegetation as a single Sustained Outage.

Sustained Outages— Falling Vegetation

R7. *Each Transmission Owner shall prevent Sustained Outages of applicable lines[6] due to vegetation falling into a conductor from within an Active Transmission Line Right of Way with the following exceptions:*

1. *Sustained Outages of applicable lines that result from natural disasters.[4]*
2. *Sustained Outages of applicable lines that result from human or animal activity.[5]*

Unlike grow-ins which are addressed in Requirement R5, a review of NERC disturbance reports related to blackouts indicates major blackouts were rarely if ever attributed to vegetation-related Sustained Outages due to vegetation falling into transmission lines. These events are known as fall-ins.

Sustained Outages due to fall-ins resulting from natural disasters are beyond the control of the Transmission Owner. In addition, it is often not possible in the aftermath of a natural disaster to perform the forensics necessary to determine what happened. Therefore, such Sustained Outages are not considered violations of this requirement.

Sustained Outages due to fall-ins that occur due to human or animal activity are beyond the control of the Transmission Owner. Therefore, such Sustained Outages are not considered violations of this requirement.

The Standard recognizes that multiple Sustained Outages on an individual line can be caused by the same vegetation. As such, the Standard recognizes these events as a single Sustained Outage.

Implement Annual Work Plan

R8. *Each Transmission Owner shall implement its annual work plan for vegetation management to accomplish the purpose of this standard within the extent of its easement and/or legal rights.*

This standard requires that the Transmission Owner implement the annual work plan and document this implementation. The annual work plan should allow sufficient time for reasonable procedural requirements to permit work on federal, state, provincial, public, tribal lands, such as permits for National Forest, Department of Transportation work, etc.

This Standard requires that the annual work plan be flexible to allow the Transmission Owner to change priorities during the year as conditions or situations dictate. For example, weather conditions (drought) could make herbicide application ineffective during the plan year. Another situational variance could be a major storm that redirects local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the Transmission Owner's system to work on another system. Examples of documented adjustments may include deferrals or additions to the annual work plan.

A measure for how this requirement was met may include documentation or other evidence of the work performed. Documentation may consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, QA work form, paid invoices, etc. to verify that the work has been completed. In addition, documentation of planned work that was deferred or not completed is needed. Documentation of deferred or incomplete work may include the reasons that the planned work was not completed. Where specific work on a line or lines was postponed, the expected completion date of the work may be included, if known. Other evidence may include photographs, inspection reports, walk-throughs, etc.

Designating Sub-200kV Lines

_R9._ *Each Reliability Coordinator in consultation with its Transmission Owner(s) and neighboring Reliability Coordinator(s) shall jointly prepare and keep current, a list of designated applicable lines that are operated below 200kV, if any, which are subject to this standard.*

Requirement R9 assigns to the Reliability Coordinator the task of designating sub-200kV lines that are subject to this standard. It can be seen that this Standard has departed from use of the term "critical" and replaced it with criteria that are more descriptive of the large disturbances this Standard intends to prevent.

The Standard places the responsibility on the Reliability Coordinator for the identification of specific sub-200kV circuits to which the Standard is to be applied. Identification of such sub-200kV circuits is to be done in consultation with the Reliability Coordinator's Transmission Owners and neighboring Reliability Coordinators.

Reliability Coordinators can offer documentation that they have consulted with their Transmission Owners and neighboring Reliability Coordinators and that they have kept current a list of designated sub-200kV transmission lines that are subject to the Standard. Documentation may include letters, e-mails, spreadsheets, etc.

Documenting Method of Identifying Sub-200kV Lines

R10. *Each Reliability Coordinator shall document its method for assessing the reliability significance of sub-200kV lines considering all of the following:*

R10.1 *Transmission lines whose loss would result in the exceedance of an Interconnection Reliability Operating Limit (IROL)*

R10.2 *Transmission lines whose loss would place the grid at an unacceptable risk of instability, separation, or cascading failures.*

Requirement R10 assigns to the Reliability Coordinator the task of documenting its methods for assessing the reliability significance of sub-200kV lines.

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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