Alberta Reliability Standard
Transmission Vegetation Management
FAC-003-AB-5

A. Introduction

1. Title: Transmission Vegetation Management

2. Number: FAC-003-AB-5

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

4. Applicability:

4.1. Functional Entities

4.1.1. applicable **legal owners** of a **transmission facility**

4.1.1.1. **legal owners** of a **transmission facility** that own **transmission facilities** defined in 4.2.

4.1.2. the **ISO**.

4.2. Transmission Facilities: Identified below (referred to as "applicable lines"), including those **transmission facilities** that cross lands owned by federal, state, provincial, public, private, or indigenous entities:

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

4.2.2. Each overhead transmission line operated below 200 kV, identified by the **ISO** per its **planning assessment** of the **near-term transmission planning horizon** as a **system element** that if lost or degraded are expected to result in instances of instability, **cascading**, or uncontrolled separation that adversely impacts the **reliability** of the **bulk electric system** for a planning event.

4.2.3. Each overhead transmission line operated below 200 kV identified as an element of a Major **WECC** Transfer Path in the **bulk electric system** by **WECC**.

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

5. Effective Date: January 1, 2028.

A line operated below 200 kV and identified in the Applicability under 4.2 becomes subject to this standard the later of: 1) 12 **months** after the date the **ISO** or **WECC** identified the line in Applicability under 4.2, or 2) January 1 of the planning year when the line is forecasted to be identified in Applicability under 4.2. A line operating below 200 kV identified in Applicability under 4.2 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.

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

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

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

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

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

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

- Requiring that vegetation be managed to prevent vegetation encroachment inside the **flashover** clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential **flashover** 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 room of vegetation conditions that could cause a **flashover** at any moment (R4);
- Requiring corrective actions to ensure that **flashover** distances will not be violated due to work constraints such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent **flashover** is completed (R7).

For this **reliability 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

Requirement 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. Requirements R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation.

Requirement 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). Requirement 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 **reliability standard** requirements for applicable lines on any kind of land or easement, whether they are federal 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 **reliability standard** the term "public lands" includes municipal lands, village lands, city lands, and a host of other governmental entities.

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

This **reliability 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 lines that are part of an **electric distribution system**. For example, localized customer service might be disrupted if vegetation were to make contact with a 69 kV transmission line supplying power to a 12 kV distribution station. However, this **reliability 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 **equipment 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 **reliability standard** places the highest priority on the management of vegetation to prevent vegetation grow-ins.

B. Requirements and Measures

R1. Each applicable **legal owner** of a **transmission facility** must manage vegetation to prevent encroachments into the **minimum vegetation clearance distance** of its applicable line(s), operating within their **equipment rating** and all **rated electrical operating conditions** of the types shown below[1] *[Alberta Risk Rating: High]* [*Time Horizon: Real-time*]:

[1] This requirement does not apply to circumstances that are beyond the control of an applicable **legal owner** of a **transmission facility** subject to this **reliability standard**, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides,

1.1. An encroachment into the **minimum vegetation clearance distance** as shown in FAC-003-Table 1, observed in real-time, absent a **sustained outage**,[2]

1.2. An encroachment due to a fall-in from inside the managed right of way that caused a vegetation-related **sustained outage**,[3]

1.3. An encroachment due to the blowing together of applicable lines and vegetation located inside the managed right of way that caused a vegetation-related **sustained outage**,[4]

1.4. An encroachment due to vegetation growth into the **minimum vegetation clearance distance** that caused a vegetation-related **sustained outage**.[5]

M1. Each applicable **legal owner** of a **transmission facility** has evidence that it managed vegetation to prevent encroachment into the **minimum vegetation clearance distance** as described in Requirement R1. Evidence may include dated attestations, dated reports containing no **sustained outages** associated with encroachment types 2 through 4 above, records confirming no real-time observations of any **minimum vegetation clearance distance** encroachments, or other equivalent evidence.

R2. [Reserved for future use]

M2. [Reserved for future use]

R3. Each applicable **legal owner** of a **transmission facility** must have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the **minimum vegetation clearance distance** of its applicable lines that account for the following: *[Alberta Risk Rating: Lower] [Time Horizon: Long Term Planning]:*

3.1. Movement of applicable line conductors under their **equipment 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, procedures, processes or specifications provided demonstrate that each of the applicable **legal owner** of a **transmission facility** can prevent encroachment into the **minimum vegetation clearance distance** considering the factors identified in the requirement.

R4. Each applicable **legal owner** of a **transmission facility**, without any intentional time delay, must notify the control room holding switching authority for the associated applicable line when the applicable **legal owner** of a **transmission facility** has confirmed the existence of a vegetation

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wind shear, fresh gale, major storms as defined either by the applicable **legal owner** of a **transmission facility** or 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 **legal owner** of a **transmission facility**'s right to exercise its full legal rights on the right of way.

[2] If a later confirmation of a **fault** by the applicable **legal owner** of a **transmission** facility shows that a vegetation encroachment within the **minimum vegetation clearance distances** has occurred from vegetation within the managed right of way, this shall be considered the equivalent of a real-time observation.

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

[4] Id.

[5] Id.

condition that is likely to cause a **fault** at any moment *[Alberta Risk Rating: Medium] [Time Horizon: Real- time].*

M4. Each applicable **legal owner** of a **transmission facility** that has a confirmed vegetation condition likely to cause a **fault** at any moment has evidence that it notified the control room holding switching authority for the associated applicable line without any intentional time delay. Evidence may include control room logs, voice recordings, switching orders, clearance orders and subsequent work orders, or other equivalent evidence.

R5. When an applicable **legal owner** of a **transmission facility** is constrained from performing vegetation work on an applicable line operating within its **equipment rating** and all **rated electrical operating conditions**, and the constraint may lead to a vegetation encroachment into the **minimum vegetation clearance distance** prior to the implementation of the next annual work plan, then the applicable **legal owner** of a **transmission facility** must take corrective action to ensure continued vegetation management to prevent encroachments [*Alberta Risk Rating: Medium*] [*Time Horizon: Operations Planning*].

M5. Each applicable **legal owner** of a **transmission facility** has evidence of the corrective action taken for each constraint where an applicable line was put at potential risk. 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, evidence that the line was de-energized, or other equivalent evidence.

R6. Each applicable **legal owner** of a **transmission facility** must perform a **vegetation inspection** of 100% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometres, etc.) at least once per calendar year and with no more than 18 **months** between inspections on the same managed right of way[6] [*Alberta Risk Rating: Medium*] [*Time Horizon: Operations Planning*].

M6. Each applicable **legal owner** of a **transmission facility** has evidence that it conducted **vegetation inspections** of the transmission line managed right of way for all applicable lines at least once per calendar year but with no more than 18 **months** between inspections on the same managed right of way. Evidence may include completed and dated work orders, dated invoices, dated inspection records, or other equivalent evidence.

R7. Each applicable **legal owner** of a **transmission facility** must complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the **minimum vegetation clearance distance**. 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 **minimum vegetation clearance distance**, 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 kilometres, etc.).

Examples of reasons for modification to annual plan may include [*Alberta Risk Rating: Medium*] [*Time Horizon: Operations Planning*]:

[6] When the applicable **legal owner** of a **transmission facility** is prevented from performing a **vegetation inspection** within the timeframe in Requirement R6 due to a natural disaster, the **legal owner** of a **transmission facility** is granted a time extension that is equivalent to the duration of the time the **legal owner** of a **transmission facility** was prevented from performing the **vegetation inspection**.

7.1. Change in expected growth rate/environmental factors

7.2. Circumstances that are beyond the control of an applicable **legal owner** of a **transmission facility**[7]

7.3. Rescheduling work between growing seasons

7.4. Crew or contractor availability/Mutual assistance agreements

7.5. Identified unanticipated high priority work

7.6. Weather conditions/Accessibility

7.7. Permitting delays

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

7.9. Emerging technologies

M7. Each applicable **legal owner** of a **transmission facility** has evidence that it completed its annual vegetation work plan for its applicable lines. Evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, dated inspection records, or other equivalent evidence.

R8.A1 The applicable **legal owner** of a **transmission facility** must submit a quarterly report, within 10 **days** of the end of each applicable quarter, to the **ISO** identifying all **sustained outages** of applicable lines operated within their **equipment rating** and all **rated electrical operating conditions** as determined by the applicable **legal owner** of a **transmission facility** to have been caused by vegetation, except as excluded in footnote 1, and including as a minimum the following:

- The name of the circuit(s), the date, time, and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the **sustained outage**; other pertinent comments; and any countermeasures taken by the applicable **legal owner** of a **transmission facility**.

A **sustained outage** is to be categorized as one of the following:

- Category 1A — Grow-ins: **Sustained outages** caused by vegetation growing into applicable lines, that are identified by the **ISO** per its **planning assessment** of the **near-term transmission planning horizon** as a facility that if lost or degraded are expected to result in instances of instability, **cascading**, or uncontrolled separation that adversely impacts the **reliability** of the **bulk electric system** by vegetation inside and/or outside of the managed right of way;
- Category 1B — Grow-ins: **Sustained outages** caused by vegetation growing into applicable lines, but are not identified by the **ISO** per its **planning assessment** of the **near-term transmission planning horizon** as a facility that if lost or degraded are expected to result in instances of instability, **cascading**, or uncontrolled separation that adversely impacts the **reliability** of the **bulk electric system** for a planning event by vegetation inside and/or outside of the managed right of way;

[7]Circumstances that are beyond the control of an applicable **legal owner** of a **transmission facility** 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 **legal owner** of a **transmission facility** or an applicable regulatory body.

- Category 2A — Fall-ins: **Sustained outages** caused by vegetation falling into applicable lines that are identified by the **ISO** per its **planning assessment** of the **near-term transmission planning horizon** as facility that if lost or degraded are expected to result in instances of instability, **cascading**, or uncontrolled separation that adversely impacts the **reliability** of the **bulk electric system** for a planning event from within the managed right of way;
- Category 2B — Fall-ins: **Sustained outages** caused by vegetation falling into applicable lines, but are not identified by the **ISO** per its **planning assessment** of the **near-term transmission planning horizon** as facilities that if lost or degraded are expected to result in instances of instability, **cascading**, or uncontrolled separation that adversely impacts the **reliability** of the **bulk electric system** for a planning event from within the managed right of way;
- Category 3 — Fall-ins: **Sustained outages** caused by vegetation falling into applicable lines from outside the managed right of way;
- Category 4A — Blowing together: **Sustained outages** caused by vegetation and applicable lines that are identified by the **ISO** per its **planning assessment** of the **near-term transmission planning horizon** as a facility that if lost or degraded are expected to result in instances of instability, **cascading**, or uncontrolled separation that adversely impacts the **reliability** of the **bulk electric system** for a planning event blowing together from within the managed right of way;
- Category 4B — Blowing together: **Sustained outages** caused by vegetation and applicable lines, but are not identified by the **ISO** per its **planning assessment** of the **near-term transmission planning horizon** as a facility that if lost or degraded are expected to result in instances of instability, **cascading**, or uncontrolled separation that adversely impacts the **reliability** of the **bulk electric system** for a planning event blowing together from within the managed right of way.

M8.A1 Each applicable **legal owner** of a **transmission facility** has evidence that it submitted a quarterly report to the **ISO** identifying all **sustained outages** of applicable lines operated within their **equipment rating** and all **rated electrical operating conditions**. Evidence may include dated emails with quarterly reports attached, or other equivalent evidence.

R8.A2 If no **sustained outages** as described in Requirement R8.A1 have occurred in a quarter, the applicable **legal owner** of a **transmission facility** must submit a report, within 10 **days** of the end of each applicable quarter, to the **ISO** confirming that no **sustained outages** have occurred that quarter.

M8.A2 Each applicable **legal owner** of a **transmission facility** has evidence that it submitted a quarterly report to the **ISO** confirming that no **sustained outages** have occurred that quarter. Evidence may include dated emails to the **ISO**, or other equivalent evidence.

R9.A1 The **ISO** will report the occurrence of any **sustained outages** as provided by an applicable **legal owner** of a **transmission facility**, as per Requirements R8.A1 and R8.A2, quarterly to **WECC.**

M9.A1 The **ISO** has evidence that it submitted a quarterly report to **WECC** identifying all **sustained outages**. Evidence may include email confirmations of receipt or other equivalent evidence.

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C. Compliance

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D. Regional Variances

None.

E. Associated Documents

AESO Information Document ID#2019-002, *Transmission Vegetation Management* and any amendments made from time to time.

Version History

Version	Effective Date	Description of Changes
AB-5	2028-01-01	Addresses FERC Order 777 and contains updated minimum vegetation clearance distances between conductors and vegetation based on empirical testing.
AB1-1	2012-12-17	Administrative update – “TFO” replaced with the “legal owner of a transmission facility”; and other minor cleanup items.
AB-1	2009-03-27	Initial release.

FAC-003 — TABLE 1 — Minimum Vegetation Clearance Distances (MVCD)[8]

For Alternating Current Voltages feet (metres)

(AC) Nominal System Voltage (KV)[+]	(AC) Maximum System Voltage (kV)[9]	MVCD Over sea level up to 500 ft	MVCD Over 500 ft up to 1000 ft	MVCD Over 1000 ft up to 2000 ft	MVCD Over 2000 ft up to 3000 ft	MVCD Over 3000 ft up to 4000 ft	MVCD Over 4000 ft up to 5000 ft	MVCD Over 5000 ft up to 6000 ft	MVCD Over 6000 ft up to 7000 ft	MVCD Over 7000 ft up to 8000 ft	MVCD Over 8000 ft up to 9000 ft	MVCD Over 9000 ft up to 10000 ft	MVCD Over 10000 ft up to 11000 ft	MVCD Over 11000 ft up to 12000 ft	MVCD Over 12000 ft up to 13000 ft	MVCD Over 13000 ft up to 14000 ft	MVCD Over 14000 ft up to 15000 ft
		(Over sea level up to 152.4 m)	(Over 153 m up to 305 m)	(Over 305 m up to 610 m)	(Over 610 m up to 915 m)	(Over 915 m up to 1220 m)	(Over 1220 m up to 1524 m)	(Over 1524 m up to 1829 m)	(Over 1829 m up to 2134 m)	(Over 2134 m up to 2439 m)	(Over 2439 m up to 2744 m)	(Over 2744 m up to 3048m)	(Over 3048 m up to 3353 m)	(Over 3353 m up to 3657 m)	(Over 3657m up to 3962 m)	(Over 3962 m up to 4268 m)	(Over 4268 m up to 4572 m)
765	800	11.6ft (3.6m)	11.7ft (3.6m)	11.9ft (3.6m)	12.1ft (3.7m)	12.2ft (3.7m)	12.4ft (3.8m)	12.6ft (3.8m)	12.8ft (3.9m)	13.0ft (4.0m)	13.1ft (4.0m)	13.3ft (4.1m)	13.5ft (4.1m)	13.7ft (4.2m)	13.9ft (4.2m)	14.1ft (4.3m)	14.3ft (4.4m)
500	550	7.0ft (2.1m)	7.1ft (2.2m)	7.2ft (2.2m)	7.4ft (2.3m)	7.5ft (2.3m)	7.6ft (2.3m)	7.8ft (2.4m)	7.9ft (2.4m)	8.1ft (2.5m)	8.2ft (2.5m)	8.3ft (2.5m)	8.5ft (2.6m)	8.6ft (2.6m)	8.8ft (2.7m)	8.9ft (2.7m)	9.1ft (2.7m)
345	362[10]	4.3ft (1.3m)	4.3ft (1.3m)	4.4ft (1.3m)	4.5ft (1.4m)	4.6ft (1.4m)	4.7ft (1.4m)	4.8ft (1.5m)	4.9ft (1.5m)	5.0ft (1.5m)	5.1ft (1.6m)	5.2ft (1.6m)	5.3ft (1.6m)	5.4ft (1.6m)	5.5ft (1.7m)	5.6ft (1.7m)	5.7ft (1.8m)
287	302	5.2ft (1.6m)	5.3ft (1.6m)	5.4ft (1.7m)	5.5ft (1.7m)	5.6ft (1.7m)	5.7ft (1.7m)	5.8ft (1.8m)	5.9ft (1.8m)	6.1ft (1.9m)	6.2ft (1.9m)	6.3ft (1.9m)	6.4ft (2.0m)	6.5ft (2.0m)	6.6ft (2.0m)	6.8ft (2.1m)	6.9ft (2.1m)
230	242	4.0ft (1.2m)	4.1ft (1.3m)	4.2ft (1.3m)	4.3ft (1.3m)	4.3ft (1.3m)	4.4ft (1.3m)	4.5ft (1.4m)	4.6ft (1.4m)	4.7ft (1.4m)	4.8ft (1.5m)	4.9ft (1.5m)	5.0ft (1.5m)	5.1ft (1.6m)	5.2ft (1.6m)	5.3ft (1.6m)	5.4ft (1.6m)
161	169	2.7ft (0.8m)	2.7ft (0.8m)	2.8ft (0.9m)	2.9ft (0.9m)	2.9ft (0.9m)	3.0ft (0.9m)	3.0ft (0.9m)	3.1ft (1.0m)	3.2ft (1.0m)	3.3ft (1.0m)	3.3ft (1.0m)	3.4ft (1.0m)	3.5ft (1.1m)	3.6ft (1.1m)	3.7ft (1.1m)	3.8ft (1.1m)
138	145	2.3ft (0.7m)	2.3ft (0.7m)	2.4ft (0.7m)	2.4ft (0.7m)	2.5ft (0.7m)	2.5ft (0.7m)	2.6ft (0.8m)	2.7ft (0.8m)	2.7ft (0.8m)	2.8ft (0.9m)	2.8ft (0.9m)	2.9ft (0.9m)	3.0ft (0.9m)	3.0ft (0.9m)	3.1ft (1.0m)	3.2ft (1.0m)
115	121	1.9ft (0.6m)	1.9ft (0.6m)	1.9ft (0.6m)	2.0ft (0.6m)	2.0ft (0.6m)	2.1ft (0.6m)	2.1ft (0.6m)	2.2ft (0.7m)	2.2ft (0.7m)	2.3ft (0.7m)	2.3ft (0.7m)	2.4ft (0.7m)	2.5ft (0.8m)	2.5ft (0.8m)	2.6ft (0.8m)	2.7ft (0.8m)
88	100	1.5ft (0.4m)	1.5ft (0.4m)	1.6ft (0.5m)	1.6ft (0.5m)	1.7ft (0.5m)	1.7ft (0.5m)	1.8ft (0.6m)	1.8ft (0.6m)	1.8ft (0.6m)	1.9ft (0.6m)	1.9ft (0.6m)	2.0ft (0.6m)	2.0ft (0.6m)	2.1ft (0.6m)	2.2ft (0.7m)	2.2ft (0.7m)
69	72	1.1ft (1.3m)	1.1ft (0.3m)	1.1ft (0.3m)	1.2ft (0.4m)	1.2ft (0.4m)	1.2ft (0.4m)	1.2ft (0.4m)	1.3ft (0.4m)	1.3ft (0.4m)	1.3ft (0.4m)	1.4ft (0.4m)	1.4ft (0.4m)	1.4ft (0.4m)	1.5ft (0.5m)	1.6ft (0.5m)	1.6ft (0.5m)

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

[8] The distances in this Table are the minimums required to prevent **flashover**; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.
[9] Where applicable lines are operated at nominal voltages other than those listed, the applicable **legal owner** of a **transmission facility** should use the maximum system voltage to determine the appropriate clearance for that line.
[10] The change in transient overvoltage factors in the calculations are the driver in the decrease in minimum vegetation clearance distances for voltages of 345 kV and above. Refer to pp.17-20 below for additional information.

TABLE 1 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[11]

For Direct Current Voltages feet (metres)

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

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

Alberta Reliability Standard
Transmission Vegetation Management
FAC-003-AB-5

Guideline and Technical Basis

Defined Terms:

Explanation for revising meaning of the term “managed right of way”:

The AESO does not define “managed right of way”. However, the AESO is aligned with NERC’s revised meaning of the term “right of way”, except that FAC-003-AB-5 has been modified to be inapplicable to **legal owners** of **generating units** and **legal owners** of **aggregated generating facilities**. The NERC glossary definition of right of way has been modified to include Generator Owners (i.e., “**legal owner** of a **generating unit** and **legal owner** of an **aggregated generating facility**”) and to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners (i.e., “**legal owner** of a **transmission facility**") may in some cases own more property or rights than are needed to reliably operate transmission lines. This definition represents a slight but significant departure from the strict legal definition of “right of way” in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the current definition to allow the use of such vegetation widths, if there were no engineering or construction standards that referenced the width of a managed 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 **reliability standard** does not require additional easement rights to be purchased to satisfy a minimum managed right of way width that did not exist prior to this standard becoming mandatory.

Explanation for revising the definition of “vegetation inspection”:

The AESO has adopted the NERC term “**vegetation inspection**” to align with the modified NERC term “Vegetation Inspection”. The current NERC *Glossary of Terms* definition of this NERC term was modified to include Generator Owners (i.e., “**legal owner** of a **generating unit** and **legal owner** of an **aggregated generating facility**”) and to allow both maintenance inspections and **vegetation inspections** to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates. The AESO has simplified its definition of **vegetation inspection** definition by referring to “**legal owners”** rather than including specific legal owner types in the definition.

Explanation of the derivation of the **minimum vegetation clearance distance**:

The **minimum vegetation clearance distance** is a calculated minimum distance that is derived from the Gallet equation. This is a method of calculating a **flashover** distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage **flashover** to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 1 of the standard provides **minimum vegetation clearance distance** values for various voltages and altitudes. The tables are based on empirical testing data from Electric Power Research Institute (“EPRI”) as requested by FERC in Order No. 777.

Project 2010-07.1 Adjusted **minimum vegetation clearance distances** per EPRI Testing:

In Order No. 777, FERC directed NERC to undertake testing to gather empirical data validating the appropriate gap factor used in the Gallet equation to calculate **minimum vegetation clearance distance**s, specifically the gap factor for the **flashover** distances between conductors and vegetation. See, Order No. 777, at P60. NERC engaged industry through a collaborative research project and contracted EPRI to complete the scope of work. In January 2014, NERC formed an advisory group to

assist with developing the scope of work for the project. This team provided subject matter expertise for developing the test plan, monitoring testing, and vetting the analysis and conclusions to be submitted in a final report. The advisory team was comprised of NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulation coordination, and vegetation management. The testing project commenced in April 2014 and continued through October 2014 with the final set of testing completed in May 2015. Based on these testing results conducted by EPRI, and consistent with the report filed in FERC Docket No RM12-4-000, the gap factor used in the Gallet equation required adjustment from 1.3 to 1.0. This resulted in increased **minimum vegetation clearance distance** values for all alternating current system voltages identified. The adjusted **minimum vegetation clearance distance** values, reflecting the 1.0 gap factor, are included in Table 1 of NERC FAC-003-4.

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

Requirement R1:

R1 is a performance-based requirement. The **reliability** objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. R1 requires each applicable **legal owner** of a **transmission facility** to manage vegetation to prevent encroachment within the **minimum vegetation clearance distance** of transmission lines. R1 is applicable to lines that are identified as an element in the Applicability section 4.2 and 4.3.

Requirement R1 states that if inadequate vegetation management allows vegetation to encroach within the **minimum vegetation clearance distance** as shown in Table 1, it is a violation of the standard. Table 1 distances are the minimum clearances that will prevent spark-over based on the Gallet equations. These requirements assume that transmission lines and their conductors are operating within their **normal rating**. If a line conductor is intentionally or inadvertently operated beyond its **normal/equipment rating** and **rated electrical operating condition** (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable **legal owner** of a **transmission facility** or the **ISO** to protect a connection 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 **minimum vegetation clearance distance** (absent a **sustained outage**), or a vegetation-related encroachment resulting in a **sustained outage** due to a fall-in from inside the managed right of way, or a vegetation-related encroachment resulting in a **sustained outage** due to the blowing together of the lines and vegetation located inside the managed right of way, or a vegetation-related encroachment resulting in a **sustained outage** due to a grow-in.

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 **reliability standard** where the **sustained outages** occur within a 24 hour period.

If the applicable **legal owner** of a **transmission facility** has applicable lines operated at nominal voltage levels not listed in Table 1, then the applicable **legal owner** of a **transmission facility** should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

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Requirement R3:

R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable **legal owner** of a **transmission facility** uses for vegetation management.

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

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an applicable **legal owner** of a **transmission facility** 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 **minimum vegetation clearance distance** clearances are never violated
2. the work methods that the applicable **legal owner** of a **transmission facility** 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 **minimum vegetation clearance distance** is illustrated in Figure 1 below.

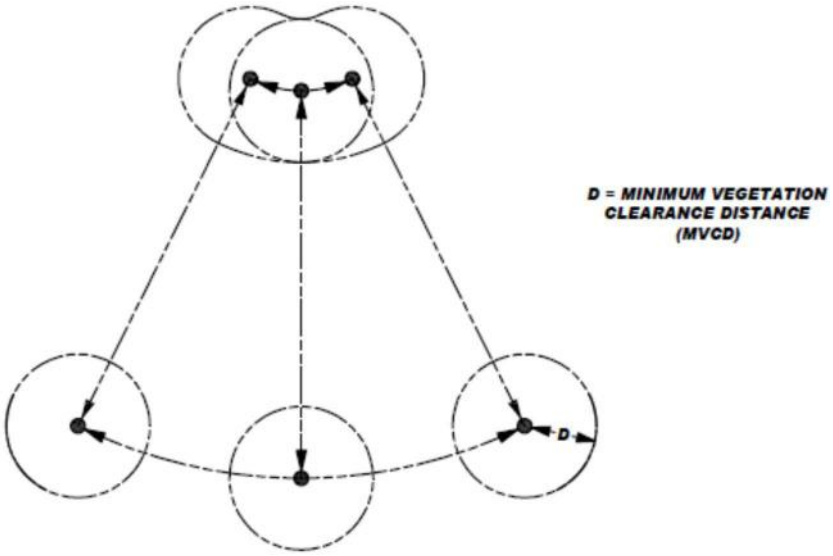

Figure 1

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

Requirement R4:

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable **legal owner** of a **transmission facility** 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 room 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 to determine that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable **legal owner** of a **transmission facility** 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 **minimum vegetation clearance distance** (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 **equipment rating**.

The applicable **legal owner** of a **transmission facility** has the responsibility to ensure the proper communication between field personnel and the control room to allow the control room to take the appropriate action until or as the vegetation threat is relieved.

Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for **corrective action plans** (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a **fault** at any moment. For example, some applicable **legal owner** of a **transmission facility** 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 room unless they pose an immediate fall-in threat.

Requirement R5:

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

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

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

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

Requirement R6:

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

Requirement R7:

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

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

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

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

When developing the annual work plan, the applicable **legal owner** of a **transmission facility** should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public,

indigenous lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable **legal owner** of a **transmission facility** 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 must be documented. Depending on the planning and documentation format used by the applicable **legal owner** of a **transmission facility**, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

Notes:

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

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

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

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

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

FAC-003-1 allowed **legal owners** of a **transmission facility** to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the **legal owners** of a **transmission facility** knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows:

3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is in service from becoming de-energized (i.e. tripped out) due

to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service AC line was approximately 2.0 per unit. This value was a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. maximum system voltage of 362 kV), the maximum transient over-voltage of an in-service AC line are created by **fault** initiation on adjacent AC lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

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

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

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

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

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

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

Comparison of spark-over distances computed using Gallet wet equations vs. IEEE 516-2003 Minimum Air Insulation Distances

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

Rationale:

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

Rationale for Applicability (section 4.2.4):

The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows:

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

Rationale for R1:

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

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable **legal owner** of a **transmission facility**'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 managed right of way is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a **cascade**.

Rationale for R3:

The documentation provides a basis for evaluating the competency of the applicable **legal owner** of a **transmission facility**'s vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the applicable **legal owner** of a **transmission facility** avoids vegetation-to-wire conflicts under all **equipment ratings** and all **rated electrical operating conditions**.

Rationale for R4:

This is to ensure expeditious communication between the applicable **legal owner** of a **transmission facility** and the control room when a critical situation is confirmed.

Rationale for R5:

Legal actions and other events may occur which result in constraints that prevent the applicable **legal owner** of a **transmission facility** from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable **legal owner** of a **transmission facility** to put interim measures in place, rather than do nothing.

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

Rationale for R6:

Inspections are used by applicable **legal owner** of a **transmission facility** to assess the condition of the entire managed right of way. 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 managed right of way. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. **Legal owners** of **transmission facilities** should consider local and environmental factors that could warrant more frequent **vegetation inspections**.

Rationale for R7:

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